PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

March 1, 2022

VIA ELECTRONIC FILING

Public Utility Commission Oregon
Attn: Filing Center
550 Capitol Street NE, Suite 215
Salem, OR 97301-2551

RE: Advice No. 22-002/Docket UE 399 – PacifiCorp's Request for General Rate Revision

PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company) submits for filing an original and 15 copies of the following proposed tariff pages associated with the Company's Tariff P.U.C. OR No. 36, applicable to electric service in the State of Oregon, together with the Executive Summary and supporting direct testimony and exhibits. The tariffs reflect an effective date of January 1, 2023. Electronic versions of the testimony, exhibits, and workpapers will be uploaded to Huddle.

Sheet	Schedule	Title
Twenty-Eighth Revision of Sheet No. INDEX-3	Tariff Index	Table of Contents - Schedules
Fourth Revision of Sheet No. 4	Schedule 4	Residential Service Delivery Service
Fourth Revision of Sheet No. 5	Schedule 5	Separately Metered Electric Vehicle Service for Residential Consumers Delivery Service
First Revision of Sheet No. 6.1	Schedule 6	Pilot for Residential Time-of-Use Service Delivery Service
Original Sheet No. 6.2	Schedule 6	Pilot for Residential Time-of-Use Service Delivery Service
Fifth Revision of Sheet No. 15-1	Schedule 15	Outdoor Area Lighting Service – No New Service Delivery Service
Fifth Revision of Sheet No. 23-1	Schedule 23	General Service – Small Nonresidential Delivery Service
Fourth Revision of Sheet No. 28-1	Schedule 28	General Service Large Nonresidential 31KW to 200 KW Delivery Service
First Revision of Sheet No. 29.1	Schedule 29	Pilot for General Service Time-Of-Use Delivery Service
Fourth Revision of Sheet No. 30-1	Schedule 30	General Service Large Nonresidential 201 KW to 999 KW Delivery Service
Fourth Revision of Sheet No. 41-1	Schedule 41	Agricultural Pumping Service Delivery Service
Fourth Revision of Sheet No. 47-1	Schedule 47	Large General Service Partial Requirements 1,000 KW and Over Delivery Service

Sheet	**Schedule**	**Title**
Fifth Revision of Sheet No. 48-1	Schedule 48	Large General Service 1,000 KW and Over Delivery Service
Fifth Revision of Sheet No. 51-1	Schedule 51	Street Lighting Service Company – Owned System Delivery Service
Fifth Revision of Sheet No. 53-1	Schedule 53	Street Lighting Service Consumer – Owned System Delivery Service
Fifth Revision of Sheet No. 54-1	Schedule 54	Recreational Field Lighting – Restricted Delivery Service
Fourth Revision of Sheet No. 76R-1	Schedule 76R	Large General Service – Partial Requirements Service Economic Replacement Power Rider Delivery Service
Twenty-eighth Revision of Sheet No. 90	Schedule 90	Summary of Effective Rate Adjustments
Fourteenth Revision of Sheet No. 98	Schedule 98	Adjustment Associated with the Pacific Northwest Electric Power Planning and Conservation Act
CANCELED First Revision of Sheet No. 104	Schedule 104	Oregon Corporate Activity Tax Recovery Adjustment
Eighth Revision of Sheet No. 200-1	Schedule 200	Base Supply Service
Eighth Revision of Sheet No. 200-2	Schedule 200	Base Supply Service
Eighth Revision of Sheet No. 200-3	Schedule 200	Base Supply Service
Tenth Revision of Sheet No. 205-1	Schedule 205	TAM Adjustment for Other Revenues
Tenth Revision of Sheet No. 205-2	Schedule 205	TAM Adjustment for Other Revenues
Tenth Revision of Sheet No. 205-3	Schedule 205	TAM Adjustment for Other Revenues
First Revision of Sheet No. 206	Schedule 206	Power Cost Adjustment Mechanism – Adjustment
First Revision of Sheet No. 207	Schedule 207	Community Solar Start-Up Cost Recovery Adjustment
Fourth Revision of Sheet No. 210-1	Schedule 210	Portfolio Time-Of-Use Supply Service
Original Sheet No. 273-1	Schedule 273	Nonresidential Accelerated Commitment Tariff (ACT)
Original Sheet No. 273-2	Schedule 273	Nonresidential Accelerated Commitment Tariff (ACT)
Original Sheet No. 273-3	Schedule 273	Nonresidential Accelerated Commitment Tariff (ACT)
Fourth Revision of Sheet No. 299	Schedule 299	Rate Mitigation Adjustment
Fourth Revision of Sheet No. 723-1	Schedule 723	General Service – Small Nonresidential Direct Access Delivery Service
Fourth Revision of Sheet No. 728-1	Schedule 728	General Service Large Nonresidential 31 KW to 200 KW Direct Access Delivery Service

Sheet	Schedule	Title
Fourth Revision of Sheet No. 730-1	Schedule 730	General Service Large Nonresidential 201 KW to 999 KW Direct Access Delivery Service
Fourth Revision of Sheet No.741-1	Schedule 741	Agricultural Pumping Service Direct Access Delivery Service
Fourth Revision of Sheet No. 747-1	Schedule 747	Large General Service Partial Requirements 1,000 KW and Over Direct Access Delivery Service
Fifth Revision of Sheet No. 748-1	Schedule 748	Large General Service 1,000 KW and Over Direct Access Delivery Service
Fifth Revision of Sheet No. 751-1	Schedule 751	Street Lighting Service Company-Owned System Direct Access Delivery Service
Fifth Revision of Sheet No. 753-1	Schedule 753	Street Lighting Service Consumer-Owned System Direct Access Delivery Service
Fifth Revision of Sheet No. 754	Schedule 754	Recreational Field Lighting–Restricted Direct Access Delivery Service
Fourth Revision of Sheet No. 776R-1	Schedule 776R	Large General Service-Partial Requirements Service-Economic Replacement Service Rider Direct Access Delivery Service
Second Revision of Sheet No. 848-1	Schedule 848	Large General Service 1,000 KW and Over Direct Access Delivery Service – Distribution Only
Second Revision of Sheet No. R10-1	Rule 10	General Rules and Regulations Billing

Copies of the Company's responses to the Standard Data Requests are being uploaded to Huddle.

Please address all communications related to this filing to:

PacifiCorp Oregon Dockets
825 NE Multnomah Street, Suite 2000
Portland, OR 97232
oregondockets@pacificorp.com

Carla Scarsella
Deputy General Counsel
825 NE Multnomah Street, Suite 2000
Portland, OR 97232
carla.scarsella@pacificorp.com

Matthew McVee
Vice President, Regulatory Policy and Operations
825 NE Multnomah Street, Suite 2000
Portland, OR 97232
matthew.mcvee@pacificorp.com

Ajay Kumar
Senior Attorney
825 NE Multnomah Street, Suite 2000
Portland, OR 97232
ajay.kumar@pacificorp.com

Katherine McDowell
McDowell Rackner Gibson PPC
419 SW 11th Ave, Suite 400
Portland, OR 97205
katherine@mrg-law.com

Additionally, PacifiCorp respectfully requests that all data requests in this docket be addressed to:

By email (preferred):	datarequest@pacificorp.com
By regular mail:	Data Request Response Center PacifiCorp 825 NE Multnomah, Suite 2000 Portland, OR 97232

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

Confidential material in support of the filing has been provided to parties under the protective order issued February 11, 2022 (Order No. 22-044).

Sincerely,

Matthew McVee
Vice President, Regulatory Policy and Operations

Enclosures

CERTIFICATE OF SERVICE

I certify that I delivered a true and correct copy of PacifiCorp's **Request for General Rate Revision** on the parties listed below via electronic mail in compliance with OAR 860-001-0180.

Service List
UE 399

PACIFICORP	
PACIFICORP, DBA PACIFIC POWER 825 NE MULTNOMAH ST, STE 2000 PORTLAND, OR 97232 oregondockets@pacificorp.com	AJAY KUMAR **(C)** **(HC)** PACIFICORP 825 NE MULTNOMAH ST STE 2000 PORTLAND, OR 97232 ajay.kumar@pacificorp.com
STAFF	
MATTHEW MULDOON **(C)** **(HC)** PUBLIC UTILITY COMMISSION OF OREGON PO BOX 1088 SALEM OR 97308 matt.muldoon@state.or.us	SOMMER MOSER **(C)** **(HC)** PUC STAFF - DEPARTMENT OF JUSTICE 1162 COURT ST NE SALEM, OR 97301 sommer.moser@doj.state.or.us

Dated this 1st day of March, 2022.

Mary Penfield
Adviser, Regulatory Operations

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 399

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

I. INTRODUCTION

PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company) is filing this request for a general rate revision under ORS 757.205 and ORS 757.220 to revise its schedules of rates and charges for electric service in Oregon, effective January 1, 2023. In this general rate case filing, the requested revenue requirement increase in this general rate case filing is $84.4 million, or 6.8 percent. This includes the impact of moving the recovery of the Oregon Corporate Activity Tax Credit (OCAT) of $6.7 million from a rider to recovery in base rates. The net increase including the elimination of the separate OCAT rider and the rebalancing of the rate mitigation adjustment is $82.2 million, or 6.6 percent. The revised rates produce revenues necessary to sustain a stable, reliable, and low-cost power supply, while preserving the Company's ability to attract capital for future investments. The Company files this executive summary and the attached Exhibit A in compliance with OAR 860-022-0019.

PacifiCorp is an electric company and public utility in Oregon within the meaning of ORS 757.005. The Public Utility Commission of Oregon (Commission) has jurisdiction over the prices and terms of PacifiCorp's electric service to its Oregon retail customers. The Company provides electric service to approximately 630,000 retail customers in Oregon and approximately 2.0 million total retail customers in California, Idaho, Oregon, Utah, Washington, and Wyoming. PacifiCorp's principal place of business is Portland, Oregon.

The Company requests that communications regarding this filing be addressed to:

PacifiCorp Oregon Dockets
825 NE Multnomah Street, Suite 2000
Portland, OR 97232
oregondockets@pacificorp.com

Carla Scarsella
Deputy General Counsel
825 NE Multnomah Street, Suite 2000
Portland, OR 97232
carla.scarsella@pacificorp.com

Matthew McVee
Vice President, Regulatory Policy and Operations
825 NE Multnomah Street, Suite 2000
Portland, OR 97232
matthew.mcvee@pacificorp.com

Katherine McDowell
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Portland, OR 97232

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

II. CASE SUMMARY

This case is based upon a historical base period of 12 months ended June 2021, with normalizing and pro forma adjustments to calculate a calendar year 2023 future test period with the exception of capital additions, which are based on calendar year-end 2022 balances. The new rates will become effective no later than January 1, 2023, assuming application of the full nine-month statutory suspension period to the 30-day effective date now contained in the tariffs. Thus, the rate effective period closely aligns with the test period in this case.

A. Return on Equity

PacifiCorp is currently forecast to earn a return on equity (ROE) in Oregon of 4.67 percent on a normalized basis for the test period. The Company is requesting a change to its authorized ROE and capital structure in this case. An increase to the equity component of the capital structure to 52.25 percent and a 9.8 percent ROE is necessary to maintain the financial integrity of the Company, while ensuring its ability to provide safe, efficient, and reliable service to its Oregon customers with minimal rate impacts.

B. Cost Drivers

1. Capital Additions

The Company continues to make new investments in its system required to provide safe, adequate, and reliable service to customers and to comply with regulatory mandates. Incremental additions included in this case include investments in all facets of the system—including transmission, generation, and distribution—to bolster reliability and improve power delivery. The largest of these costs is the remainder of the investment in TB Flats Wind Project, which the Commission approved as prudent and in the public interest in the Company's last general rate case, docket UE 374 (2021 Rate Case).[1]

2. Wildfire and Vegetation Management Costs

With the increasing threat of wildfires in Oregon, the Commission in the 2021 Rate Case and the Oregon State Legislature through Senate Bill 762 have recognized the necessity of wildfire mitigation efforts and wildfire protection plans to a utility's system. PacifiCorp

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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).

has undertaken a number of measures to mitigate the wildfire threat, which has increased capital investment and operating and maintenance expenses. Further, unrelated to the wildfire mitigation measures, the Company is incurring additional spending with respect to vegetation management as a result of increasing costs.

3. Modifications to Existing Regulatory Mechanisms

In PacifiCorp's 2021 Rate Case, the Commission approved a Wildfire Mitigation and Vegetation Management Recovery (WMVM) Mechanism in order to allow an opportunity for the Company to recover wildfire mitigation and vegetation management costs above the amount for vegetation management costs included in rates. PacifiCorp is proposing modifications to this mechanism—namely to remove wildfire mitigation capital investments and operation and maintenance expenses from the mechanism in light of the enactment of Senate Bill 762 and to modify the existing mechanism to better align recovery of vegetation management costs with results. The Company is also proposing modifications to its Transition Adjustment Mechanism and Power Cost Adjustment Mechanism to improve the accuracy of net power costs and to ensure the appropriate risk balance for the recovery of those costs.

III. TESTIMONY SUMMARY

The Company's direct case consists of the testimony and exhibits of 11 witnesses:

Joelle R. Steward, Senior Vice President, Regulation and Customer/Community Solutions, provides an overview of PacifiCorp's current filing and support of the Company's policy positions throughout this filing. Ms. Steward also discusses the proposed updates to the Oregon depreciable lives and/or Exit Orders for certain coal-fired resources. She also discusses updates to the WMVM Mechanism.

Nikki L. Kobliha, Chief Financial Officer, addresses the Company's overall cost of capital recommendation for the Company, including a capital structure to maximize value and minimize risk and the current cost of debt. She also addresses the Company's pension settlement accounting.

Ann E. Bulkley, Principal at The Brattle Group, provides a comparison of PacifiCorp's business and financial risk compared to peer utilities, recommends a ROE, and provides supporting analyses.

Michael G. Wilding, Vice President, Energy Supply Management, addresses proposed changes to the Company's Transition Adjustment Mechanism and Power Cost Adjustment Mechanism.

Timothy J. Hemstreet, Managing Director of Renewable Energy and Business Development, provides an overview of the TB Flats Wind Project and provides an update on the status of the project.

Richard A. Vail, Vice President of Transmission Services, describes PacifiCorp's transmission system and the benefits it provides to Oregon customers and the major new transmission system projects included in this general rate case filing, specifically the Goshen to Sugarmill to Rigby 161 kilovolt (kV) and the Jordanelle to Midway 138 kV transmission line projects.

Allen Berreth, Vice President of Transmission and Distribution Operations, discusses wildfire risk and the Company's wildfire related transmission and distribution investments and vegetation management expenses included in this rate case. He also discusses the proposed revisions to the WMVM Mechanism.

Erik Anderson, Strategic Manager of Renewable Energy and Emerging Technology, describes PacifiCorp's proposed voluntary renewable energy tariff for nonresidential customers, which is proposed Schedule 273, the Accelerated Commitment Tariff.

Kenneth Lee Elder, Jr., Load Forecasting Manager, describes how the Company developed the load forecast used in this general rate case filing.

Sherona L. Cheung, Revenue Requirement Manager, summarizes the overall test period revenue requirement, pro forma adjustments, and the rate base calculation methodology.

Robert M. Meredith, Director of Pricing and Cost of Service, provides PacifiCorp's allocation and rate design, and discusses how the proposed tariff changes recover the proposed 2023 revenue requirement to achieve fair, just, and reasonable prices for customers.

IV. CONCLUSION

The Company requests that the Commission issue an order approving the proposed rate changes and tariffs described above.

Respectfully submitted March 1, 2022.

Carla Scarsella

____

Carla Scarsella
Deputy General Counsel

Ajay Kumar
Senior Attorney

PacifiCorp d/b/a Pacific Power

Exhibit A

Exhibit A
Summary of Requested Electric General Rate Increase
Oregon Allocated
Filed March 1, 2022

(A)	Total revenues collected under proposed rates:	$1,044,764,668
(B)	**Base**	
	Revenue change requested:	
	Total:	$84,399,519
	Net of credits from federal agencies:	$84,399,519
	Net[1]	
	Revenue change requested:	
	Total:	$82,171,330
	Net of credits from federal agencies:	$82,171,330
(C)	**Base**	
	Percentage change in revenues requested:	
	Total %:	6.8%
	Net of credits from federal agencies:	6.8%
	Net[1]	
	Percentage change in revenues requested:	
	Total %:	6.6%
	Net of credits from federal agencies:	6.6%
(D)	Test period:	Calendar year 2023
(E)	Requested return on capital:	7.21%
	Requested return on equity:	9.8%
(F)	Rate base proposed in filing:	$4,199,121,534
(G)	Results of operation:	
	Utility operating income, before proposed change:	$190,246,188
	Utility operating income, after proposed change:	$302,848,497

(H) Effect of rate change on each customer class:

	Base Change	Net Change[1]
• Residential:	12.6%	9.1%
• Small General Service (Schedule 23):	10.3%	9.5%
• General Service 31-200 kW (Schedule 28):	-0.8%	0.0%
• General Service 201-999 kW (Schedule 30):	-2.4%	0.0%
• Large General Service >= 1,000 kW (Schedule 48):	-1.9%	5.9%
• Agriculture Pumping Service (Schedule 41):	19.1%	13.2%
• Street lighting:	-11.5%	0.0%
• Total	6.8%	6.6%

(I) Information Required by Utility Staff General Rate Case Data Request Form A: Provided under separate cover

[1] Net Change reflects the net impact to customers on January 1, 2023, of the proposed price change including resetting Schedule 299, the Rate Mitigation Adjustment and eliminating the separate charge for the Oregon Corporate Activity Tax Recovery Adjustment, Schedule 104. Including these adjustments, a net increase of $82.2 million, or 6.6 percent overall, is proposed to take effect on January 1, 2023.

ACRONYMS AND ABBREVIATIONS

Acronym	Term
2020 Protocol	2020 PacifiCorp Inter-Jurisdictional Allocation Protocol
2021 Rate Case	the Company's 2021 general rate case, docket UE 374
2021 Rate Case	Docket UE 374
2022AS RFP	2022 All-Source RFP
2023 GRC	this general rate case (docket UE 399)
2023 Rate Case	this general rate case (docket UE 399)
AAC	all-aluminum conductor
ACC	Arizona Commission Corporation
ACSR	aluminum conductor steel-reinforced
ACT	Accelerated Commitment Tariff
ADIT	Accumulated Deferred Income Tax
AFUDC	Allowance for Funds Used During Construction
aMW	average Megawatts
APS	Arizona Public Service Company
ASC 715	Accounting Standards Codification Topic 715-30—Compensation—Retirement Benefits
ATRR	annual transmission revenue requirement
B.C.	British Columbia
BAA	Balancing Authority Areas
Base Period	historical period of the 12 months ended June 2021
BES	Bulk Electric System
BHE	Berkshire Hathaway Energy Company
BOSR	Body of State Regulators
CAISO	California Independent System Operator
CAPEX	capital expenditures
CAPM	Capital Asset Pricing Model
CBO	Congressional Budget Office
CFO	cash from operations
CFO pre-W/C	Cash from Operations pre-Working Capital
Commission	Public Utility Commission of Oregon
Company	PacifiCorp d/b/a Pacific Power
CPI	Consumer Price Index
DCF	Discounted Cash Flow
ECD	embedded cost differential
EDIT	Excess Deferred Income Tax
EIA	Energy Information Administration
EIM	Energy Imbalance Market
EPA	Environmental Protection Agency
EPS	Earnings Per Share
ESM	Energy Supply Management
FERC	Federal Energy Regulatory Commission
FHCA	Fire High Consequence Areas
FOMC	Federal Open Market Committee
Functionalized Oregon Results of Operations Report	PacifiCorp's December 2021 Functionalized Oregon Results of Operations Report
GDP	Gross Domestic Product
GHG	greenhouse gas
HB	House Bill
HLH	heavy load hours
HLP	Heber Light and Power
IHS	Information Handling Services
IRP	Integrated Resource Plan
KHSA	Klamath Hydroelectric Settlement Agreement
kV	kilovolt
kWh	kilowatt-hour
LIBOR	London Inter Bank Offer Rate
Marginal Cost Study	PacifiCorp's State of Oregon December 2023 Marginal Cost Study
Michigan PSC	Michigan Public Service Commission
Mid-C	Mid-Columbia
MSP	multi-state process
MVA	Megavolt ampere
MW	megawatts

ACRONYMS AND ABBREVIATIONS

Acronym	Term
MWh	megawatt-hour
NEO	Named Executive Officers
NERC	North American Electric Reliability Corporation
NOAA	National Oceanic and Atmospheric Administration
Non-NPC	Non-Net Power Costs
Non-T&D	non-transmission and distribution
NPC	net power costs
NWRFC	Northwest River Forecast Center
O&M	operations and maintenance
OAR	Oregon Administrative Rule
OATT	Open Access Transmission Tariff
OCAT	Oregon Corporate Activity Tax
ORS	Oregon Revised Statute
P/E	price-to-earnings
PACE	PacifiCorp Balancing Authority Area East
PacifiCorp	PacifiCorp d/b/a Pacific Power
PACW	PacifiCorp Balancing Authority Area West
participant	nonresidential customer
PCAM	Power Cost Adjustment Mechanism
PGE	Portland General Electric Company
PHFU	Plant Held for Future Use
PPA	power purchase agreement
PTC	Production Tax Credit
PV	Palo Verde
RAS	remedial action scheme
RBM	regional business manager
REC	Renewable Energy Certificate
Report	Company's Oregon results of operations report
RFP	request for proposal
RMA	Rate Mitigation Adjustment
ROE	return on equity
ROR	Rate of Return
RPS	Renewable Portfolio Standards
RRA	Regulatory Research Associates
S&P	Standard & Poor's
SAE	Statistically Adjusted End-Use
SB	Senate Bill
SCR	selective catalytic reduction system
TAM	Transition Adjustment Mechanism
TCJA	Tax Cuts and Jobs Act
TEP	Transportation Electrification Program
Test Period	the 12-month period ending December 31, 2023
TPL Standards	transmission planning standards
U.S	United States
UAMPS	Utah Associated Municipal Power Systems
Value Line	Value Line Investment Survey
VERS	variable energy resources
Vestas	Vestas-American Wind Technology, Inc.
VRET	Voluntary Renewable Energy Tariff
WEBA	Wage and Employee Benefits adjustments
WECC	Western Electricity Coordinating Council
WMVM	Wildfire Mitigation and Vegetation Management Cost Recovery Mechanism
WPP	Western Power Pools
WPP	Wildfire Protection Plans
WRAP	Western Resource Adequacy Program
WROE	Weighted Return on Equity
WTG	wind turbine generator
YOY	year-over-year

Docket No. UE 399
Exhibit PAC/100
Witness: Joelle R. Steward

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Joelle R. Steward

March 2022

TABLE OF CONTENTS

ATTACHED EXHIBIT

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 Joelle R. Steward and my business address is 1407 West North Temple, Salt Lake City, Utah 84116. I am currently employed as Senior Vice President, Regulation and Customer/Community Solutions.

Q. Please describe your education and professional experience.

A. I have a Bachelor of Arts degree in Political Science from the University of Oregon and an M.A. in Public Affairs from the Hubert Humphrey Institute of Public Policy at the University of Minnesota. Between 1999 and March 2007, I was employed as a Regulatory Analyst with the Washington Utilities and Transportation Commission. I joined the Company in March 2007 as a Regulatory Manager, responsible for all regulatory filings and proceedings in Oregon. On February 14, 2012, I assumed responsibilities overseeing cost of service and pricing for PacifiCorp. In May 2015, I assumed broader oversight over Rocky Mountain Power's regulatory affairs in addition to the cost of service and pricing responsibilities. In 2017, I assumed the role as Vice President, Regulation for Rocky Mountain Power; in November 2021, I assumed my current role as Senior Vice President, Regulation and Customer/Community Solutions for PacifiCorp.

Q. Have you testified in other regulatory proceedings?

A. Yes. I have testified on various matters in the states of Idaho, Oregon, Utah, Washington, and Wyoming.

II. PURPOSE OF TESTIMONY

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

A. I provide an overview of PacifiCorp's current filing and support the Company's policy positions throughout this filing. I also give context for this rate filing, which comes just over a year after the order in PacifiCorp's last general rate case, docket UE 374 (2021 Rate Case).[1] The Company is facing increasing requirements regarding decarbonization in House Bill (HB) 2021 and wildfire mitigation in Senate Bill (SB) 762 and needs to have a fair opportunity to recover its prudent and reasonable costs to support access to financial markets to make investments needed to comply with state statutes and policies. The Company has and continues to make a concerted effort to manage its controllable costs, which allowed it to stay out of general rate cases beyond its commitment made in docket UE 263[2] until it filed its 2021 Rate Case. While the Company has been transitioning to a non-emitting energy resource mix, work needs to be done to meet the requirements of HB 2021. This work coupled with the investment required to protect its system and customers from the increasing wildfire threat and increasing costs of vegetation management, will help position the Company to continue to respond proactively and ensure delivery of safe, reliable, affordable electric service to its customers.

The requested revenue requirement increase in this general rate case filing is $84.4 million, or 6.8 percent. This includes the impact of moving the recovery of the

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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] In its 2013 Rate Case, the Company committed to not filing a rate case prior to January 1, 2016. *See In the matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 263, Order No.13-474, at 6 (Dec. 18, 2013). In a letter to its Oregon customers, PacifiCorp further committed not to file a general rate case prior to January 1, 2018.

Oregon Corporate Activity Credit (OCAT) of $6.7 million from a rider to recovery in base rates. The net increase including the elimination of the separate OCAT rider and the rebalancing of the rate mitigation adjustment, which is discussed further in the testimony of Mr. Robert M. Meredith, is $82.2 million, or 6.6 percent.

Q. How is your testimony structured?

A. Section III of my testimony provides a description of PacifiCorp and its Oregon service territory. Section IV provides an overview of PacifiCorp's last rate case filing. Section V provides an overview of this rate case filing, including a discussion of key drivers. Section VI discusses the Company's proposed revisions to the depreciable lives and / or Exit Orders for certain coal-fueled generation units approved in the 2021 Rate Case. Section VII discusses the proposed modifications to the Wildfire Mitigation and Vegetation Management Cost Recovery Mechanism (WMVM Mechanism). Section VIII addresses PacifiCorp's proposed Voluntary Renewable Energy Tariff (VRET) which is called the Accelerated Commitment Tariff (ACT) program. Section IX addresses the proposed limited modifications to the Transition Adjustment Mechanism (TAM) Rate Year Update and the proposed revisions to the TAM guidelines and Power Cost Adjustment Mechanism (PCAM). Finally, Section X introduces the witnesses submitting testimony in support of PacifiCorp's rate case filing.

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

A. I recommend that the Public Utility Commission of Oregon (Commission):

- Authorize an overall increase of $84.4 million or approximately 6.8 percent. The support for the increase is set forth in my testimony and the testimony of the other Company witnesses;
- Approve as prudent the Company's request to include the incremental additions to the Company's rate base, including the remaining portion of the TB Flats Wind Project, for a total rate base of approximately $4.2 billion, as discussed in the testimony of various witnesses in this rate case;
- Approve an overall cost of capital of 7.21 percent, which is comprised of a capital structure of 52.25 percent equity, 47.74 percent long-term debt, and 0.01 percent preferred stock as supported by Ms. Nikki L. Kobliha; and a return on equity (ROE) of 9.8 percent as supported by Ms. Ann E. Bulkley;
- Approve the proposed updates to the Oregon depreciable lives and/or revisions to the Exit Orders for coal-fired resources approved in the 2021 Rate Case to align with the Company's 2021 Integrated Resource Plan (IRP) as described in my testimony;
- Approve the proposed revisions to the WMVM Mechanism as discussed in my testimony and the testimony of Mr. Allen Berreth;
- Approve PacifiCorp's proposed VRET, the ACT, Schedule 273, as discussed in my testimony and the testimony of Mr. Erik Anderson;
- Approve the proposed modifications to the TAM and the proposed revisions to the TAM guidelines and PCAM as explained by Mr. Michael G. Wilding; and
- Approve the cost allocations and rate design proposals set forth in the testimony of Mr. Meredith.

III. DESCRIPTION OF PACIFICORP AND OREGON SERVICE AREA

Q. Please provide a brief description of PacifiCorp.

A. As an investor-owned, multi-jurisdictional electric utility, PacifiCorp serves two million customers in six western states: California, Idaho, Oregon, Utah, Washington, and Wyoming.

The Company serves its customers with a vast, integrated system of generation and transmission that spans 10 states and connects customers and communities across the West. PacifiCorp's integrated system provides benefits to customers in all six states and includes generation, transmission, and distribution assets. PacifiCorp owns, or has interests in thermal, hydroelectric, wind-powered, solar, and geothermal generating facilities, with a net-owned capacity of 11,668 megawatts. PacifiCorp buys and sells electricity on the wholesale market with other utilities, energy marketing companies, financial institutions, and other market participants to balance and optimize the economic benefits of electricity generation, retail customer loads, and existing wholesale transactions.

PacifiCorp provides wholesale transmission service under its open access transmission tariff approved by the Federal Energy Regulatory Commission and owns or has interests in approximately 17,700 miles of transmission lines. PacifiCorp operates two Balancing Authority Areas—PacifiCorp Balancing Authority Area East and PacifiCorp Balancing Authority Area West that together comprise the largest privately owned and operated grid in the Western United States.

Q. Please describe PacifiCorp's Oregon service area.

A. In Oregon, PacifiCorp serves approximately 630,000 customers. The Company's Oregon service area is comprised of urban and rural areas. PacifiCorp's sales and revenues are distributed among residential customers, small businesses, and large businesses served under retail tariffs subject to the jurisdiction of the Commission. Table 1 below provides the June 2021 number of retail customers and usage by customer class.

Table 1: Number of Customers and Usage in PacifiCorp's Oregon Service Area

Class	Number of Customers	Usage (megawatt-hours)
Residential	539,475	5,901,942
Commercial	80,387	5,654,081
Industrial	1,711	1,601,028
Irrigation	6,578	303,317
Lighting	1,467	35,659
Total	629,618	13,496,028

IV. PREVIOUS RATE CASE HISTORY

Q. Please discuss PacifiCorp's most recent general rate case and its outcome.

A. On February 14, 2020, the Company filed its 2021 Rate Case requesting an increase in revenues from Oregon operations of $78.0 million or a 6 percent increase to its revenue requirement.[3] During the course of the proceeding, as a result of adjustments, PacifiCorp revised its request to an increase of $46.3 million or approximately 3.5 percent.[4] Following a fully litigated proceeding, on

[3] The overall impact to customer rates in the Company's direct filing was an increase of $21.6 million or 1.6 percent, which reflected an increase in revenue requirement of $78.0 million; an increase related to the recovery of costs associated with the closing of Cholla Unit 4 of $17.3 million; a decrease of $24.9 million to amortize deferred tax benefits associated with the Tax Cuts and Jobs Act; and a decrease of $49.2 million related to the concurrently filed 2021 TAM, Docket No. UE 375.
[4] Order 20-473 at 1.

December 18, 2020, the Commission entered an order approving a decrease to PacifiCorp's revenue requirement of $20.9 million or 1.6 percent.[5]

Q. Why is PacifiCorp filing a rate case just over a year after the issuance of the Commission's Order 20-473 in the 2021 Rate Case?

A. The Commission made a number of important findings in Order 20-473 to provide PacifiCorp an opportunity to recover its prudently incurred costs going forward. The Commission approved full recovery of and on the vast majority of the Company's capital investments, including the Energy Vision 2020 projects that increased PacifiCorp's non-emitting generation portfolio with new and repowered wind generation resources and new transmission. The Commission also adopted the WMVM Mechanism to allow the Company the opportunity to recover capital costs and operations and maintenance (O&M) expenses above the amounts approved in the revenue requirement.

However, despite the findings in Order 20-473, PacifiCorp is still under-recovering costs as demonstrated by the fact that under current rates the Company will earn an overall ROE in Oregon of 4.67 percent, which is significantly below the Company's currently authorized ROE of 9.5 percent. It is important that the Company has the opportunity to recover its prudently incurred costs, particularly in light of enactment of HB 2021, which requires PacifiCorp to reduce emissions associated with the electricity it delivers -- 80 percent by 2030, 90 percent by 2035, and completely eliminate emissions by 2040.

[5] *Id.*

PacifiCorp has been transitioning to a non-emitting energy resource mix while continuing to provide safe, reliable, and affordable electric service to its customers. The Company's 2021 IRP preferred portfolio includes retirement of 14 of the coal-fueled generation units by 2030 and 19 of the units by the end of the planning period of 2040.[6] This is in addition to the recently closed units, including Carbon Units 1 and 2, and Cholla Unit 4, and the conversion of Naughton Unit 3 to natural gas. As reliance on coal-fueled generation is decreasing, an increasing segment of the Company's resource mix is renewable generation. In its 2013 IRP, renewable resources made up only 1.5 percent of PacifiCorp's resource capacity.[7] In its 2021 IRP, PacifiCorp forecasts 34 percent of its resource capacity will be renewable energy resources and 30 percent coal-fueled generation by 2023.[8]

The Company's 2021 IRP was not prepared pursuant to HB 2021 as the 2021 IRP was issued before the new law became effective in September 2021. Further, it is my understanding that HB 2021 applies to IRPs issued after January 1, 2022.[9] Significant capital investment will be needed to meet the requirements of HB 2021 and the Company must be well positioned to have the opportunity to recover its prudent costs and have access to capital markets to finance these investments. Therefore, the Company has filed this rate case to recover prudently incurred capital costs incurred since the 2021 Rate Case, such as the remaining investment in the TB Flats Wind Project, along with reasonable O&M expenses, including vegetation management; to adjust capital structure so that the Company can maintain its current

[6] PacifiCorp's 2021 IRP at 299. *See,* https://www.pacificorp.com/energy/integrated-resource-plan.html.
[7] PacifiCorp's 2013 IRP at 229 (Apr. 30, 2013).
[8] PacifiCorp's 2021 IRP at 305.
[9] HB 2021, Section 4(3)(a).

credit rating; and to request revisions to certain cost recovery mechanisms, such as the WMVM Mechanism, TAM, and PCAM. I explain the drivers of this rate case filing further below. Along with the other witnesses sponsoring direct testimony in this proceeding, I support the Company's proposals.

Q. How does PacifiCorp's current and proposed overall retail average rate in Oregon compare to the national average?

A. PacifiCorp's efficient operations and focus on rate stability for customers have resulted in the Company's average price being approximately 18 percent lower than the national average of 11.20 cents per kWh for the 12 months ending June 30, 2021, as reported by the Edison Electric Institute Summer 2021 Typical Bills and Average Rates Report. Attached to my testimony as Exhibit PAC/101 is a chart comparing PacifiCorp's Oregon rates to national averages.

Even with its proposed rates in this proceeding, the Company's rates would remain about 12 percent lower than the national average.

V. OVERVIEW OF RATE CASE

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

A. In this section of my testimony, I discuss the individual components of the Company's filing, including the cost drivers leading to the filing.

Q. What test period is the Company proposing in this rate proceeding?

A. The test period the Company is proposing is a fully forecasted test year for the 12 months ended December 31, 2023, with the exception of capital additions, which are based on calendar year-end 2022 balances. The testimony of Ms. Sherona L. Cheung discusses the development of the test year.

Q. What rate of return is PacifiCorp requesting in this case?

A. The Company is requesting approval of an overall rate of return of 7.21 percent. The overall rate of return is comprised of a 9.8 percent ROE as supported by Ms. Bulkley. As explained by Ms. Kobliha, PacifiCorp is requesting approval of a capital structure that is comprised of 52.25 percent equity, 47.74 percent long-term debt, and 0.01 percent of preferred stock. Together, this results in a weighted ROE of 5.12 percent. Notably, the Company is requesting an authorized ROE below the range recommended by Ms. Bulkley. The Company's proposed capital structure balances the prevailing market conditions that support a higher ROE, as described by Ms. Bulkley, with the Company's capital financing needs and impacts on customers. Ms. Cheung applies the overall rate of return to the Company's cost of service.

Q. Please describe the major drivers of PacifiCorp's rate request.

A. The major drivers of the Company's general rate case filing are: (1) the remainder of the TB Flats Wind Project; (2) wildfire and vegetation management costs; and (3) modifications to existing regulatory mechanisms. I discuss each of these drivers in more detail below.

Q. Please describe the driver related to the TB Flats Wind Project in this rate request.

A. Currently, a portion of the costs of the TB Flats Wind Project are already reflected in rates. In the 2021 Rate Case, the TB Flats Wind Project was found prudent and in the public interest. Due to construction delays associated with COVID-19, the entire project was not completed in 2020 and only costs associated with turbines that achieved commercial operation by December 20, 2020, were included in rates. The

Project was completed in July 2021 and in this proceeding the Company is seeking to include the remainder of the investment in TB Flats Wind Project in rates. Please see Mr. Timothy J. Hemstreet's testimony for further discussion of costs associated with the remainder of the investment in TB Flats Wind Project.

Q. Please describe the driver related to wildfire mitigation and vegetation management costs.

A. Both the Commission in Order 20-473 and the Oregon State Legislature in SB 762 have recognized the importance of wildfire mitigation/wildfire protection plans to all Oregonians as a result of the increasing wildfire risk in the state.[10] As a result, the Company has undertaken a number of measures to mitigate wildfire threat which has increased capital investment and O&M expenses. Furthermore, the Company is incurring additional spending related to vegetation management that is unrelated to wildfire mitigation as a result of an escalation in costs and change in program activities. Mr. Berreth discusses wildfire and vegetation management costs further in his testimony.

Q. Please describe the driver related to existing regulatory mechanisms.

A. PacifiCorp is not being afforded a fair opportunity to recover its costs in two major cost categories for which the Commission has established specific recovery mechanisms: wildfire and vegetation management costs and net power costs (NPC). With respect to wildfire and vegetation management costs, the Company is proposing two modifications to the WMVM Mechanism—namely to remove the costs associated with Company's wildfire protection plan from the mechanism and to

[10] *See* Order 20-473 at 120-125 and SB 762.

modify the existing mechanism to better align recovery of vegetation management costs with results. As to NPC, in this proceeding the Company is proposing limited modifications to the TAM and PCAM to improve the accuracy of NPC and to ensure the appropriate risk balance for the recovery of NPC. Mr. Berreth and I both address the proposed modifications to the WMVM Mechanism in our respective testimonies. Mr. Wilding discusses the limited modifications to the TAM and PCAM in his testimony.

Q. Is PacifiCorp seeing inflationary increases in this rate case?

A. Yes. In developing revenue requirement, the Company projects inflationary increases or decreases in costs based on third-party IHS Markit indices. These indices have changed since the Company's 2021 Rate Case as inflation is rising. In the Company's filing, inflation accounts for approximately $8.4 million or 0.8 percent of the requested total non-NPC revenue requirement. Ms. Cheung incorporates the impact of inflation on revenue requirement in her testimony.

Q. Is the Company requesting to include the final decommissioning cost estimates from the 2021 Rate Case in this proceeding?

A. No. In its 2021 Rate Case, the Commission approved PacifiCorp's motion to expand the scope of the proceeding to include the determination of the depreciation rates, including decommissioning costs, for its coal-fueled resources and allow PacifiCorp to supplement its filing with materials submitted in docket UM 1968, the Company's then pending depreciation proceeding.[11] In Order 20-473, the Commission found that

[11] Docket No. UE 374, ALJ Ruling (Apr. 2, 2020); see also, *In the matter of PacifiCorp, dba Pacific Power, Application for Authority to Implement Revised Depreciation Rates,* Docket No. UM 1968, Order No. 20-470 (Dec. 16. 2020).

a separate proceeding should be opened to determine final decommissioning cost estimates.[12] Thus, on July 8, 2021, PacifiCorp filed an application for authority to implement a decommissioning cost recovery adjustment and coal removal mechanism, which initiated docket UM 2183.[13] In that proceeding, the parties are working on agreed-to language for the independent evaluator request for proposal (RFP) and modified protective order and the Company expects to issue the independent evaluator RFP to market shortly. At this time, the Company is not seeking to consolidate these two proceedings.

Q. Is PacifiCorp requesting to consolidate other applications with this rate case proceeding?

A. Yes. After this rate case filing, the Company will file a motion to consolidate a number of open deferral applications to establish ratemaking treatment for these items in this rate case. These applications include:

- Docket UM 1964, Deferred Accounting for PacifiCorp's Transportation Electrification Program;[14]
- Docket UM 2134, Deferred Accounting for costs associated with Cedar Springs 2;[15]

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[12] Order No. 20-473 at 17.
[13] *In the Matter of PacifiCorp, dba Pacific Power, Application for Authority to Implement a Decommissioning Cost Recovery Adjustment and Coal removal Mechanism*, Docket No. UM 2183, Application (July 8, 2021).
[14] *In the Matter of PacifiCorp dba Pacific Power Application for Approval of Deferred Accounting for a Balancing Account Related to PacifiCorp's Transportation Electronification Program,* Docket No. UM 1964, Application filed July 27, 2018 (corrected on Jan. 27, 2022), reauthorizations filed on Mar. 24, 2020 (corrected on Jan. 27, 2022) and Mar. 23, 2021 (corrected on Jan. 27, 2022).
[15] *In the Matter of PacifiCorp dba Pacific Power Application for Approval of Deferred Accounting for Costs Relating to a Renewable Resource Pursuant to ORS 469A.120,* Docket No. UM 2134, Application filed Dec. 10, 2020.

- Docket UM 2142, Deferred Accounting for costs associated with Cholla Unit 4 property taxes;[16]
- Docket UM 2167, Deferred Accounting for revenues associated with Renewable Energy Credits (RECs) from Pryor Mountain;[17]
- Docket UM 2185, Deferred Accounting for costs associated with Non-Contributory Defined Benefit Pensions Plans;[18] and
- Docket UM 2186, Deferred Accounting for the costs associated with the TB Flats Wind Project.[19]

Receiving Commission decisions on these applications to allow amortizing these deferred costs is an important step in ensuring the Company can adequately recover its prudent and reasonable expenses.

Q. Is PacifiCorp proposing major updates to rate spread and rate design?

A. No, because the Commission approved a stipulation among certain parties regarding rate spread and rate design in Order 20-473,[20] the Company is only proposing discrete changes to how rates are currently designed. PacifiCorp is proposing that the price change resulting from this proceeding be applied on an equal percentage basis across prices for each class of schedules, except the residential class. For the residential

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[16] *In the Matter of PacifiCorp dba Pacific Power Application for Approval of Deferred Accounting for a Balancing Account Related to PacifiCorp's Transportation Electronification Program,* Docket No. UM 1964, Application filed July 27, 2018.
[17] *In the Matter of PacifiCorp dba Pacific Power Application for Approval of Deferred Accounting for Revenues Associated with RECs from Pryor Mountain,* Docket No. UM 2167, Application filed May 13, 2021.
[18] *In the Matter of PacifiCorp dba Pacific Power Application for Approval of Deferred Accounting and Accounting Order Related to Non-Contributory Defined Benefit Pensions Plans,* Docket No. UM 2185, Application filed July 27, 2021.
[19] *In the Matter of PacifiCorp dba Pacific Power Application for Approval of Deferred Accounting for Costs Related to a Renewable Resource Pursuant to ORS 469A.120,* Docket No. UM 2186, Application filed July 27, 2021.
[20] Order No. 20-473 at 140 and Appendix A.

class, the Company proposes increasing the single-family basic charge from $9.50 to $12 per month and replacing the inverted block energy charge structure with seasonal rates where winter prices are lower than summer prices. The rate design proposals are discussed in Mr. Meredith's direct testimony.

VI. DEPRECIABLE LIVES AND/OR EXIT ORDERS AND EXIT DATES FOR CERTAIN COAL-FUELED PLANTS

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

A. In this section of my testimony, I explain PacifiCorp's proposal regarding updates to the depreciable lives and/or Exit Orders of certain coal-fueled generation plants approved in the 2021 Rate Case.

Q. What is an "Exit Order"?

A. My understanding of Oregon energy policy, specifically, Section 1 of SB 1547, is that utilities are to eliminate the costs and benefits of coal-fueled resources from retail electric rates on or before January 1, 2030.[21] Thus, the 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol (2020 Protocol), which was approved by the Commission on January 23, 2020,[22] details the process by which Oregon can exit coal-fueled resources by a date certain.

[21] Chapter 028, 2016 Laws, SB 1547, Section 1, Elimination of Coal from Electric Supply.
[22] *In the matter of PacifiCorp, dba Pacific Power, Request to Initiate an Investigation of Multi-Jurisdictional Issues and Approve an Inter-Jurisdictional Cost Allocation Protocol*, Docket No. UM 1050, Order No. 20-024 (Jan. 23, 2020).

Section 4.1 of the 2020 Protocol outlines a process by which state commissions may issue "Exit Orders"[23] that provide for specific "Exit Dates,"[24] after which the state will no longer receive any benefits or be subject to any new costs related to the resource for which the Exit Order was issued. The 2020 Protocol states that Exit Orders may be established through the approval of the 2020 Protocol, in depreciation dockets, general rate cases, or other appropriate regulatory proceedings.

In requesting approval of the 2020 Protocol, the Company did not request, and the Commission did not approve, issuance of Exit Orders or Exit Dates for coal-fueled resources.[25] Instead, in its 2021 Rate Case, the Company requested the Commission issue Exit Orders with specific Exit Dates for the majority of PacifiCorp's coal-fueled resources. However, the Commission opted to issue Exit Orders with specific Exit Dates for a subset of units requested by the Company, including Cholla Unit 4, Jim Bridger Unit 1, Craig Units 1 and 2, Naughton Units 1 and 2, Colstrip Units 3 and 4, and Dave Johnston Units 1 through 4.[26]

Q. Please identify the coal-fueled generation units for which PacifiCorp is requesting updates to depreciable lives and/or Exit Orders.

A. PacifiCorp is requesting updates to the depreciable lives and/or Exit Orders for the following units: Colstrip Units 3 and 4; Craig Unit 2; Hayden Units 1 and 2; and Jim Bridger Units 1 and 2.

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[23] Exit Order means an order entered by a state commission approving the discontinuation of the use of an existing resource and exclusion of costs and benefits of that resource from customer rates by that state on a date certain. See Appendix A to the 2020 Protocol for the defined term as used in the 2020 Protocol.
[24] Exit Date means the date on which PacifiCorp will discontinue the allocation and assignment of costs and benefits of a coal-fueled Interim Period Resource to the State issuing the Exit Order, as defined in the 2020 Protocol.
[25] *See* Order No. 20-024, at 7-8.
[26] Order No. 20-473 at 12.

Q. Why is PacifiCorp proposing updates for these units?

A. Since Order 20-473, the Company has issued its 2021 IRP, which reflects the most current information on the retirement of the Company's coal-fueled generation units. Table 2 below compares the depreciable lives and Exit Orders approved by the Commission in Order 20-473 and the retirement dates identified in the 2021 IRP for Colstrip Units 3 and 4; Craig Unit 2; Hayden Units 1 and 2; and Jim Bridger Units 1 and 2.

Table 2: Comparison of Depreciable Lives and Exit Order dates to the Retirement Dates Identified in the 2021 IRP

Coal Plant/Unit	Oregon Depreciable Life[27]	Oregon Exit Orders[28]	2021 IRP Retirement[29]
Colstrip 3-4	2027	2027	2025
Craig 2	2026	2026	2028
Hayden 1	2023	N/A	2028
Hayden 2	2023	N/A	2027
Jim Bridger 1	2023	2023	Convert to Gas
Jim Bridger 2	2025	N/A	Convert to Gas

Q. What is the Company's proposal regarding Colstrip Units 3 and 4?

A. In Order 20-473, the Commission approved Exit Orders with Exit Dates of December 31, 2027 for Colstrip Units 3 and 4.[30] However, the Commission urged PacifiCorp to evaluate whether an earlier exit for these units is economic for its Oregon customers in the Company's 2021 IRP.[31] Of the 22 coal-fueled generation

[27] Order No. 20-473 at 97; *see also, In the matter of PacifiCorp, dba Pacific Power, Application for Authority to Implement Revised Depreciation Rates,* Docket No. UM 1968, Order No, 20-470 (Dec. 16, 2020).
[28] Order No. 20-473 at 12; the Commission declined to issue exit orders for Hayden Units 1 and 2 and Jim Bridger 2.
[29] 2021 IRP at 15; see https://www.pacificorp.com/energy/integrated-resource-plan.html.
[30] Order No. 20-473 at 12.
[31] *Id.*, 12-13.

units currently serving PacifiCorp customers, the 2021 IRP preferred portfolio includes retirement of 14 units by 2030 and 19 units by the end of the planning period.[32] Specifically, the 2021 IRP preferred portfolio accelerates the retirement of Colstrip Units 3 and 4 to 2025 instead of a retirement date of 2027 as used in the 2019 IRP.[33] Thus, PacifiCorp's 2021 IRP Action Plan Item 1(a) is to work closely with co-owners of Colstrip Units 3 and 4 to seek the most cost effective path forward toward the target exit date of December 31, 2025.[34]

Because of the earlier target retirement date, PacifiCorp proposes that the depreciable lives for Colstrip Units 3 and 4 be updated to reflect the new 2025 retirement. Approval of the updated depreciable life for these units is appropriate as it satisfies the matching principle and avoids intergenerational equity issues because the Company's proposal recovers plant investment from customers who are benefiting from the generation prior to retirement of the unit. See Ms. Cheung's direct testimony with respect to the calculation of the revenue requirement using the updated depreciable lives. The Company is not requesting that the Exit Order approved in Order 20-473 for Colstrip Units 3 and 4 be updated at this time until discussions with the joint owners of these units provide more certainty on the closure dates. As reflected in the 2021 IRP, PacifiCorp, which is a minority owner in these units, will work closely with co-owners of Colstrip Units 3 and 4 to seek the most cost-effective path forward toward the target exit date of December 31, 2025 for these units.

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[32] 2021 IRP at 299.
[33] *Id.*
[34] *Id.* at 321.

Q. What is the Company's proposal regarding Craig Unit 2?

A. In July 2020, the joint owners of Craig Unit 2 announced plans to retire this unit on September 30, 2028. The new retirement date for Craig Unit 2 was included in PacifiCorp's 2021 IRP preferred portfolio.[35] However, in the 2021 Rate Case, the Commission approved depreciation rates based on a 2026 depreciable life and an Exit Order with an Exit Date of December 31, 2026.[36] As a result, PacifiCorp proposes to extend the depreciable life for Craig Unit 2 to 2028. Approval of the updated depreciable life for this unit is appropriate as it satisfies the matching principle and avoids intergenerational equity issues because the Company's proposal matches the recovery of the plant investment to customers who are benefiting from the generation prior to retirement of the unit. See Ms. Cheung's direct testimony with respect to the calculation of the revenue requirement using the updated depreciable life.

Additionally, the Company requests that the Exit Order approved in Order 20-473 for Craig Unit 2 be updated to reflect an Exit Date of September 30, 2028. This change will result in a common closure date for all the Company's jurisdictions for Craig Unit 2.

Q. What is the Company's proposal regarding Hayden Units 1 and 2?

A. In the 2021 Rate Case, PacifiCorp did not request Exit Orders with Exit Dates for Hayden Units 1 and 2. The Commission-approved depreciable lives for Hayden Units 1 and 2 is 2023. Per Section 4.1.5 of the 2020 Protocol, on or before February 1, 2021, the Company had to make state-specific recommendations to the various state commissions for treatment of Hayden Units 1 and 2. On February 1,

[35] 2021 IRP at 299.
[36] Order No. 20-473 at 12, 97.

2021, PacifiCorp filed a letter with the Commission in docket UM 1050 that notified the Commission that the joint owners of Hayden Units 1 and 2 announced the retirement of Hayden Unit 1 on December 31, 2028, and Hayden Unit 2 on December 31, 2027.[37] As a result, the new retirement dates for these units were included in PacifiCorp's 2021 IRP preferred portfolio.[38]

PacifiCorp proposes to update the depreciable lives for Hayden Units 1 and 2 to correspond with their planned retirements. Updating the depreciable lives is consistent with the matching principle and avoids intergenerational equity issues by matching the recovery of the plant investment to customers who are benefiting from the generation prior to retirement of the unit. See Ms. Cheung's direct testimony with respect to the calculation of the revenue requirement using the updated depreciable lives.

Further, the Company requests that the Commission issue Exit Orders with Exit Dates for Hayden Units 1 and 2 of December 31, 2028, and December 31, 2027, respectively. Per the joint owners planned retirement and the 2021 IRP, the Company anticipates that these units will cease operation by the requested Exit Dates. It is appropriate for the Commission to issue Exit Orders for the Hayden units at this time as it provides certainty with regard to PacifiCorp's compliance with SB 1547.
For coal-fueled resources anticipated to cease operations before December 31, 2029, issuance of Exit Orders now provides a clear pathway for PacifiCorp to remove the costs of these units from rates consistent with the cessation of operations.

[37] Docket No. UM 1050, Letter Regarding PacifiCorp Notice of Plan for Hayden Units 1 and 2 (Feb. 1, 2021).
[38] 2021 IRP at 299.

Q. What actions follow the issuance of an Exit Order for a specific coal-fired resource by one or more states?

A. An Exit Order triggers certain actions identified in the 2020 Protocol, including the establishment of decommissioning cost obligations for exiting states, a potential process for the determination of capital addition responsibility, and a process for the consideration of reassignment of the freed-up capacity to other states that have not issued Exit Orders. The 2020 Protocol envisions that sufficient time, at least four years, is provided from the issuance of an Exit Order to the Exit Date to allow for reassignment of the exiting state's share of the coal-fired resource to be considered by other states. The Exit Order alone does not provide for reassignment, or any associated shift in responsibility for future operation and maintenance or capital costs and reassignment of costs and benefits must be approved by states without Exit Orders in order for cost responsibility to shift among states and for benefits of the resource to accrue to a different state.

Q. How will PacifiCorp remove the Hayden Units 1 and 2 from electric rates?

A. In its 2021 Rate Case, the Company had proposed a Generation Plant Removal Mechanism to recover the closure costs for coal-fueled resources that received Exit Orders. In Order 20-473, the Commission declined to approve a mechanism and decided that it would evaluate a cost recovery mechanism for closure costs associated with retired coal-fueled generation units at the conclusion of a proceeding to review PacifiCorp's decommissioning costs, as a recovery mechanism will also need to be in place to recover those costs as well.[39] Thus, on July 8, 2021, PacifiCorp filed an

[39] Order No. 20-473 at 20-21.

application for authority to implement a decommissioning cost recovery adjustment and coal removal mechanism, which initiated docket UM 2183.[40] The recovery of retired coal-fueled generation units will be addressed in docket UM 2183.

Q. What is the Company's proposal regarding Jim Bridger Units 1 and 2?

A. In Order 20-473, the Commission approved an Exit Order with an Exit Date of December 31, 2023, for Jim Bridger Unit 1 and declined to approve an Exit Order with an Exit Date for Jim Bridger Units 2 through 4.[41] However, the Company's 2021 IRP preferred portfolio includes conversion of Units 1 and 2 to natural gas peakers in 2024.[42] As a result, the 2021 IRP action plan's Item 1(c) includes initiating the process of ending coal-fueled operations at Jim Bridger Units 1 and 2 and seek permitting for natural gas conversion by 2024.[43]

Because of the gas conversions for Jim Bridger Units 1 and 2, Exit Orders with Exit Dates are no longer needed for these units. However, because an Exit Order was approved for Jim Bridger Unit 1 and to allow for a gas conversion, PacifiCorp requests that the Commission modify the Exit Order approved in Order 20-473 to specify that the Exit Order only applies to Jim Bridger Unit 1 as a coal-fueled resource. This modification is appropriate because it will allow the Company to operate Jim Bridger Unit 1 as a natural gas-fueled generation unit after 2023, allowing for the units to continue providing benefits to Oregon customers and remain in Oregon rates

[40] Docket No. UM 2183.
[41] Order No. 20-473 at 12-13.
[42] 2021 IRP at 299.
[43] *Id.,* 322.

Q. Has the forecasted cost of the gas conversion of Jim Bridger Units 1 and 2 been included for recovery in this rate case filing?

A. No. Because of the timing of the project, PacifiCorp will seek recovery of the capital costs associated with the gas conversion of Jim Bridger Units 1 and 2 in a future general rate case where the Commission can review the prudence and reasonableness of those costs.

VII. WILDFIRE MITIGATION AND VEGETATION MANAGEMENT COST RECOVERY MECHANISM

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

A. In this section of my testimony, I discuss PacifiCorp's proposed changes to the WMVM Mechanism that was approved in the 2021 Rate Case.

Q. Please explain the WMVM Mechanism.

A. The WMVM Mechanism approved in Order 20-473 allows the Company recovery of capital costs and O&M expenses related to wildfire mitigation and vegetation management for a period of three years (2021 through 2023).[44] The first filing PacifiCorp will make under the mechanism will be on May 5, 2022, for recovery of 2021 costs, with a rate effective date of November 5, 2022. Under the mechanism, the first $6.645 million of capital costs and O&M expenses above the $30 million of O&M expenses that is included in the Company's rates is recoverable based on an earnings test that is scaled based on the Company meeting certain performance metrics. The performance metrics are based on the safety audit conducted in the year of the cost recovery filing. For example, for the filing to be made in May 2022 for

[44] Order No. 20-473 at 120-125.

the recovery of 2021 costs, the performance metrics used to apply the earnings test will be based on the 2022 safety audit.

Under the earning test, the greater the number of violations in the subsequent year's audit, the lower the calculated ROE to get recovery. If the earnings test prevents recovery in a given year, capital investments may be recovered in a subsequent rate case. Table 3 below sets forth the earnings test to which capital costs and O&M expenses are subject.

Table 3: WMVM Mechanism's Earnings Test for First Incremental Spend

First increment of spend: $6.645 million above $30.0 million		
$6.645 million includes capital and O&M		
Applicable Earnings Test		
Performance Metric	**Number of Violations**	**Earnings Test**
Below Violation Level I	0 - 74	None
At or above Violation Level I, but below Violation Level II	75 - 149	Authorized ROE minus 100 basis points
At or above Violation Level II, but below Violation Level III	150 - 199	Authorized ROE minus 150 basis points
At or above Violation Level III	200+	Authorized ROE minus 200 basis points

Q. Under the WMVM Mechanism, does the earnings test change for capital costs and O&M expenses above $36.645 million?

A. Yes. Capital costs and O&M expenses above $36.645 million in the previous year are subject to a more relaxed earnings test, which is still scaled based on the number of violations as set forth in Table 4 below.

Table 4: WMVM Mechanism's Earnings Test for Additional Spend

Additional spend: Amounts above $36.645 million		
Additional amount includes capital and O&M		
Applicable Earnings Test		
Performance Metric	**Number of Violations**	**Earnings Test**
Below Violation Level II	0 - 149	None
Level II or above and at least one violation in FHCA zone	150+	Authorized ROE minus 50 basis points

Q. What are the changes PacifiCorp is proposing to the WMVM Mechanism?

A. There are two category of changes that PacifiCorp is recommending. The first category relates to the wildfire mitigation component of the mechanism based on the enactment of SB 762.[45] The second category relates to the recovery of capital costs and O&M expenses under the mechanism. The Company proposes that both categories of changes take effect for the costs incurred under the mechanism in calendar year 2022 for which the Company will request recovery of in May 2023.

Q. Please explain the proposed change to the mechanism as it relates to SB 762.

A. On July 19, 2021, Governor Brown signed SB 762 into law. My understanding is that SB 762 requires electric utilities to file with the Commission risk-based wildfire protection plans that include a means for mitigating wildfire risk, balancing costs with the resulting reduction of risk, and preventive actions and programs to minimize risk of utility facilities causing a wildfire. Additionally, SB 762 Section 3(8) states:

> All reasonable operating costs incurred by, and prudent investments made by, a public utility to develop, implement or operate a wildfire protection plan under this section are recoverable in the rates of the public utility from all customers through a filing under ORS 757.210 to 757.220. The commission shall establish an automatic adjustment

[45] Chapter 592, 2021 Laws, SB 762.

> clause, as defined in ORS 757.210, or another method to allow timely recovery of the costs.

SB 762 allows for electric utilities to request recovery of the costs associated with a wildfire protection plan through an automatic adjustment clause or another method to allow for timely recovery.

Under SB 762, PacifiCorp filed its wildfire protection plan with the Commission on December 30, 2021, in docket UM 2207.[46] Further, on January 5, 2022, the Company filed an application for deferral accounting for 2022 costs associated with the wildfire protection plan.[47] PacifiCorp will also file in the second quarter of 2022 an application for approval of an automatic adjustment clause for costs incurred beginning in 2022 related to the implementation of its wildfire protection plan. If the automatic adjustment clause is approved, the Company would seek to recover the deferred 2022 costs related to its wildfire protection plan through the automatic adjustment clause.

Because the Company will be requesting an automatic adjustment clause for recovery of costs associated with its wildfire protection plan, the wildfire mitigation component of the WMVM Mechanism becomes redundant for those costs incurred beginning in 2022. Thus, PacifiCorp recommends that recovery of wildfire protection plan capital costs and O&M expenses be removed from the WMVM Mechanism beginning for costs incurred in 2022.

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[46] *In the Matter of PacifiCorp, dba Pacific Power, Wildfire Protection Plan,* Docket No. UM 2207, PacifiCorp Wildfire Protection Plan (Dec. 30, 2021).

[47] *In the Matter of PacifiCorp dba Pacific Power Application for Approval of Deferred Accounting for Operating Costs and Capital Investments Made to Implement and Operate PacifiCorp's Oregon Wildfire Protection Plan,* Docket No. UM 2221, Application filed Jan. 5, 2022.

Q. Why is the Company proposing to remove the recovery of the costs associated with its wildfire protection plan from an already Commission-approved recovery mechanism?

A. As I noted above, SB 762 provides for "*[a]ll* reasonable operating costs incurred by, and prudent investments made by, a public utility to develop, implement or operate a wildfire protection plan under this section are recoverable in the rates."[48] While I am not an attorney, the language of SB 762 provides for the recovery of all costs to implement a wildfire protection plan and does not restrict the recovery of a utility's costs to implement its plan other than providing that operating expenses be reasonable and capital investments prudent. However, if the Company's wildfire protection plan operating expenses and capital costs were to be recovered through the WMVM Mechanism, they would be subjected to the earnings test contrary to SB 762 and make recovery of all costs dependent upon the number of vegetation management violations per a Staff audit report.

In recognizing the wildfire threat is of the upmost concern to Oregon, in Order 20-473, the Commission approved a performance-based recovery mechanism to allow for the recovery of the Company's wildfire mitigation and vegetation management efforts. After the Commission's Order was issued, the State Legislature took action to address the wildfire threat Oregonians are facing and enacted a law that in part requires a utility to submit a formal wildfire protection plan; the Commission to approve the plan or approve the plan with conditions; and the Commission to establish an automatic adjustment clause or other method for the timely recovery of

[48] SB 762, Section 3(8). (emphasis added)

all costs related to developing, implementing, or operating a wildfire protection plan. The WMVM Mechanism, which was based on the mitigation efforts described in the Company's 2021 Rate Case, does not allow for the timely recovery of all prudent and reasonable costs related to the Company's wildfire protection plan that the Commission is considering in docket UM 2207. By removing recovery of the wildfire protection plan costs from the mechanism, the Company can pursue an automatic adjustment clause to timely recover all prudent and reasonable costs associated with the capital-intensive implementation of the wildfire protection plan as contemplated by SB 762.

In signing SB 762, Governor Brown stated that "we still have a lot of work ahead of us to implement this bill."[49] She added that "we are laying the roadmap and devoting the resources to transform our approach to meet the challenges of this new era of wildfire" and SB 762 "exemplifies the proposition that by working together, we can create a safer, stronger, and more fire resilient Oregon."[50] Part of the roadmap set forth in SB 762 is preparation and approval of utilities' wildfire protection plans, the implementation of those plans, and the recovery of prudent capital costs and reasonable O&M expenses related to those plans. Removing recovery of wildfire protection plan costs from the WMVM Mechanism and allowing recovery of those costs through the to-be-filed automatic adjustment clause will better position the Company to meet the challenges of this new era of wildfire.

[49] State of Oregon Press Release, "Governor Kate Brown Signs Bill to Modernize And Improve Wildfire Preparedness" (July 30, 2021) *See*, https://www.oregon.gov/newsroom/Pages/NewsDetail.aspx?newsid=64182
[50] *Id.*

Q. What changes is the Company proposing to the recovery of costs under the WMVM Mechanism?

A. The Company is proposing four modifications to the WMVM Mechanism:

1. Modification of the violation criteria for the level of violations;
2. Modification of the Safety Staff audit to verifiable violations on lines trimmed within two years;
3. Modification of the basis point penalty to a sharing percentage; and
4. Full recovery of costs due to inflation and new regulatory mandates.

These proposed modifications are further discussed by Mr. Berreth in his direct testimony.

Q. Why is PacifiCorp proposing these changes to the WMVM Mechanism?

A. The WMVM Mechanism is an important cost recovery mechanism for the Company to be able to recover the costs related to vegetation management. In approving the WMVM Mechanism, the Commission agreed finding that:

> … in an environment where wildfire risk mitigation is of utmost concern to our state, we find that the recovery of the incremental costs of vegetation management and wildfire mitigation between rate cases will ensure the company has both the obligation and the incentive to complete those investments and improve its vegetation management practices in an appropriate timeframe. We find that annual recovery of prudently incurred costs for vegetation management and wildfire mitigation, tied to demonstrated improvements to the company's vegetation management practices, appropriately matches the costs borne by and benefits received by ratepayers. Accordingly, we find that the annual deferral of costs within the mechanism is authorized under ORS 757.259(2)(e).51

However, as approved, the WMVM Mechanism does not allow the Company a fair opportunity to recover prudently incurred costs. Specifically, it does not balance the

[51] Order 20-473 at 120. (footnote omitted)

obligation and incentive regarding vegetation management practices. In fact, the mechanism provides the perverse incentive for the Company to overspend on O&M related to vegetation management instead of strategically incurring O&M in a manner that decreases violations in a cost-conscious manner for customers. Under the current mechanism, the Company is incented to spend the minimum or maximum amounts to receive recovery, which does not make economic sense and would negatively impact customers. For example, to ensure recovery of its prudent and reasonable costs, PacifiCorp could spend $100 million on vegetation management, while the number of violations would decrease, rates would drastically increase. The Company is proposing revisions to the mechanism to allow it to engage in a methodological spend over the course of several years that allows for the fair recovery of its costs.

Q. Will PacifiCorp's modifications allow for a fair opportunity to recover prudent costs under the WMVM Mechanism?

A. Yes. PacifiCorp's proposed modifications will better balance the obligation and incentive related to vegetation management practices. The Company is proposing to remove certain costs that are outside the Company's control from the application to the earnings test, such as costs related to changes to the Commission's vegetation management rules and increasing costs of labor and materials. PacifiCorp is also recommending changes to the violation criteria to align it better with other Oregon electric utilities and modifying the basis point penalty to a sharing percentage. The changes emphasize a proper incentive regarding vegetation management activities under the mechanism.

VIII. VOLUNTARY RENEWABLE ENERGY TARIFF

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

A. In this section of my testimony, I discuss the Company's proposed VRET, which the Company has named the Accelerated Commitment Tariff or the ACT, Schedule 273.

Q. What is a VRET?

A. A VRET is generally a utility offering that allows nonresidential customers to voluntarily elect to pay a premium rate to obtain service from a renewable energy resource, and have the environmental attributes retired on their behalf. VRETs provide nonresidential customers additional choices to support renewable energy development beyond what a utility has already planned.

Q. Why is PacifiCorp proposing the ACT, which is a VRET, at this time?

A. PacifiCorp's nonresidential customers are looking for a renewable energy offering from the Company beyond the purchase of unbundled RECs under the Company's Schedule 272. The ACT will provide these customers a program that will allow them more flexibility to meet their renewable energy goals and support acceleration of adoption of renewable energy beyond the requirements of HB 2021 for decarbonization of the Company's base electric supply.

Furthermore, it is my understanding that under HB 2021, an electric utility is required to reduce greenhouse gas emissions below the baseline emissions levels by 80 percent by 2030; 90 percent by 2035; and 100 percent by 2040. As I discussed earlier in my testimony, PacifiCorp is transitioning its generation resources to a non-emitting renewable energy mix and has made substantial progress. However, work lies ahead to meet the targets in HB 2021. The ACT will allow PacifiCorp to add incremental renewable resources, beyond planned economic investments, in an expedited manner, accelerating state policy of decarbonization through the voluntary participation of the Company's participating customers while limiting impacts to all customers. Because the incremental cost of the bundled renewable resource would be borne by the participating customer, the ACT would serve to advance implementation of HB 2021 renewable energy targets while protecting non-participating customers. This reduces the Company's need for incremental resources to reach its HB 2021 targets. Under the ACT, customers will be able to support near-term additionality by adding sufficient demand to bring new renewables to the grid that would not have come online otherwise.

Q. Would approval of the ACT program provide protection to vulnerable populations within PacifiCorp's service territory?

A. Yes. While the ACT program will only be available to the Company's nonresidential customers, it provides protection to PacifiCorp's more vulnerable customers by accelerating PacifiCorp's decarbonization through resources paid for entirely by participating customers in the ACT program. The ACT program accelerates PacifiCorp's decarbonization goals by adding non-emitting resources to the Company's system without spreading the incremental cost to all customers, thereby reducing the impact of Oregon's energy goals on residential customers, including vulnerable populations. While the associated RECs are retired for the participating customer, meeting demand through non-emitting resources reduces emissions at no incremental cost to PacifiCorp's other customers. Further, if there is a circumstance where the length of the renewable resource obligation is less than the life of the resource or term of the power purchase agreement, PacifiCorp's nonparticipating customers will benefit from the remaining production through energy from the non-emitting resource that has either been paid completely by a participating customer or has been substantially bought down.

Q. Please describe the structure of PacifiCorp's proposed ACT program.

A. Under the tariff, PacifiCorp will purchase bundled renewable energy resources and the corresponding RECs that meet the customer's need. Under the ACT, the participating customer will be responsible for the cost of the bundled energy renewable resource and as a result, costs of the resource are not shifted to non-subscribing customers. Further, participating customers must continue to take service under, and pay all components of, its applicable rate and all supplemental schedules and riders as determined for each delivery point. Direct access service customers are not eligible for the program. See Mr. Anderson's testimony for further details of the ACT and how it complies with the eight conditions set forth in Commission Order 21-091.[52]

IX. TRANSITION ADJUSTMENT MECHANISM AND POWER COST ADJUSTMENT MECHANISM

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

A. In this section of my testimony, I discuss the Company's proposed changes to the TAM and PCAM.

[52] *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.

Q. What are the TAM and PCAM?

A. The TAM forecasts a level of NPC for the following calendar year, which is recovered through Schedule 201. The PCAM, which is filed in the year following the TAM test year, allows for an opportunity for recovery or return of un-forecasted deviations in NPC if certain thresholds are met. Mr. Wilding further describes these mechanisms in his testimony.

Q. What changes is PacifiCorp proposing to the TAM and PCAM?

A. With respect to the TAM, PacifiCorp is proposing that an update during the rate year be performed, and a revision to the TAM Guidelines to allow more accurate hydrologic data into the NPC forecast. As to the PCAM, the Company is proposing to (1) adjust the deadbands to be symmetrical and lower the upper deadband from $30 million to $15 million; (2) set the earnings test to PacifiCorp's authorized ROE; and (3) allow for the recovery of extraordinary, meaningful, and unpredictable events to be outside the deadbands, sharing bands, and earnings test.

Q. Why is PacifiCorp proposing to change the TAM at this time?

A. The Commission has noted in the TAM that "the accuracy of forecasts is of significant importance to setting fair and reasonable rates."[53] The Commission concludes that its "goal is to achieve an accurate forecast of PacifiCorp's [NPC] for the upcoming year."[54] As explained by Mr. Wilding, the modest changes to the TAM would increase accuracy by using the latest hydrologic information, allow the Company to incorporate the latest information and costs that are necessary to meet

[53] *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).
[54] *Id.*

PacifiCorp's resource adequacy requirements for the Western Power Pool's Western Resource Adequacy Program.

Q. Why is PacifiCorp proposing changes to the PCAM?

A. In the 2021 Rate Case, PacifiCorp proposed significant changes to the PCAM mechanism.[55] The Commission found that "PacifiCorp has not demonstrated a fundamental change in the risk balance between customers and the company that occurs with its power costs."[56] The loss of dispatchable generation across the west has fundamentally altered the risk balance on power costs. Through Mr. Wilding's testimony, the Company presents evidence on the shifting risk balance that is currently occurring in the PCAM and proposes modest changes to help remedy these issues.

X. INTRODUCTION OF COMPANY WITNESSES

Q How is PacifiCorp presenting this case?

A. PacifiCorp is presenting the following direct testimony in support of its rate case filing:

- In Exhibit PAC/200, Nikki L. Kobliha, PacifiCorp's Chief Financial Officer, will provide the Company's overall cost of capital recommendation for the Company, including a capital structure to maximize value and minimize risk and the current cost of debt. Ms. Kobliha also addresses pension settlement accounting.
- In Exhibit PAC/300, Ann E. Bulkley, Principal at The Brattle Group, provides a comparison of PacifiCorp's business and financial risk compared to peer utilities, recommends a cost of equity, and provides supporting analyses.

[55] Docket No. UE 374, Exhibit PAC/500, Wilding Direct.
[56] Order 20-473 at 129-130.

- In Exhibit PAC/400, Michael G. Wilding, the Company's Vice President of Energy Supply Management, addresses proposed changes to the Company's Transition Adjustment Mechanism and Power Cost Adjustment Mechanism.
- In Exhibit PAC/500, Timothy J. Hemstreet, the Company's Managing Director of Renewable Energy and Business Development, provides an update on the TB Flats Wind Project.
- In Exhibit PAC/600, Richard A. Vail, PacifiCorp's Vice President of Transmission Services, discusses the Goshen to Sugarmill to Rigby 161 kilovolt (kV) and Jordanelle to Midway 138kV transmission lines.
- In Exhibit PAC/700, Allen Berreth, the Company's Vice President of Transmission and Distribution Operations, discusses wildfire risk and the Company's incremental investments in wildfire mitigation, and vegetation management.
- In Exhibit PAC/800, Erik Anderson, discusses the Company's proposed ACT program.
- In Exhibit PAC/900, Kenneth Lee Elder, discusses the Company's load forecast for the test year.
- In Exhibit PAC/1000, Sherona L Cheung, PacifiCorp's Revenue Requirement Manager, summarizes the overall test year revenue requirement, pro forma adjustments, and the rate base calculation methodology.
- In Exhibit PAC/1100, Robert M. Meredith, Director of Pricing and Tariff Policy, provides PacifiCorp's cost allocation and rate design, and discusses how the proposed tariff changes recover the proposed 2023 revenue requirement to achieve fair, just, and reasonable prices for customers.

XI. CONCLUSION

Q. Please summarize your recommendations to the Commission.

A. I recommend the Commission approve the proposals described in Section II of my testimony, including:

- Authorizing an overall increase of $84.4 million or approximately 6.8 percent;
- Approving a total rate base of approximately $4.2 billion, as discussed in the testimony of various witnesses in this rate case;
- Approve an overall cost of capital of 7.21 percent, which is comprised of a capital structure of 52.25 percent equity, 47.74 percent long-term debt, and 0.01 percent preferred stock and a ROE of 9.8 percent;
- Approving the proposed updates to the Oregon depreciable lives and/or revisions to the Exit Orders for coal-fired resources approved in the 2021 Rate Case as described in my testimony;
- Approving the proposed revisions to the WMVM Mechanism;
- Approving PacifiCorp's proposed VRET, the ACT, Schedule 273; and
- Approving the proposed modifications to the TAM and PCAM.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 399
Exhibit PAC/101
Witness: Joelle R. Steward

BEFORE THE PUBLIC UTILITY COMMISSION

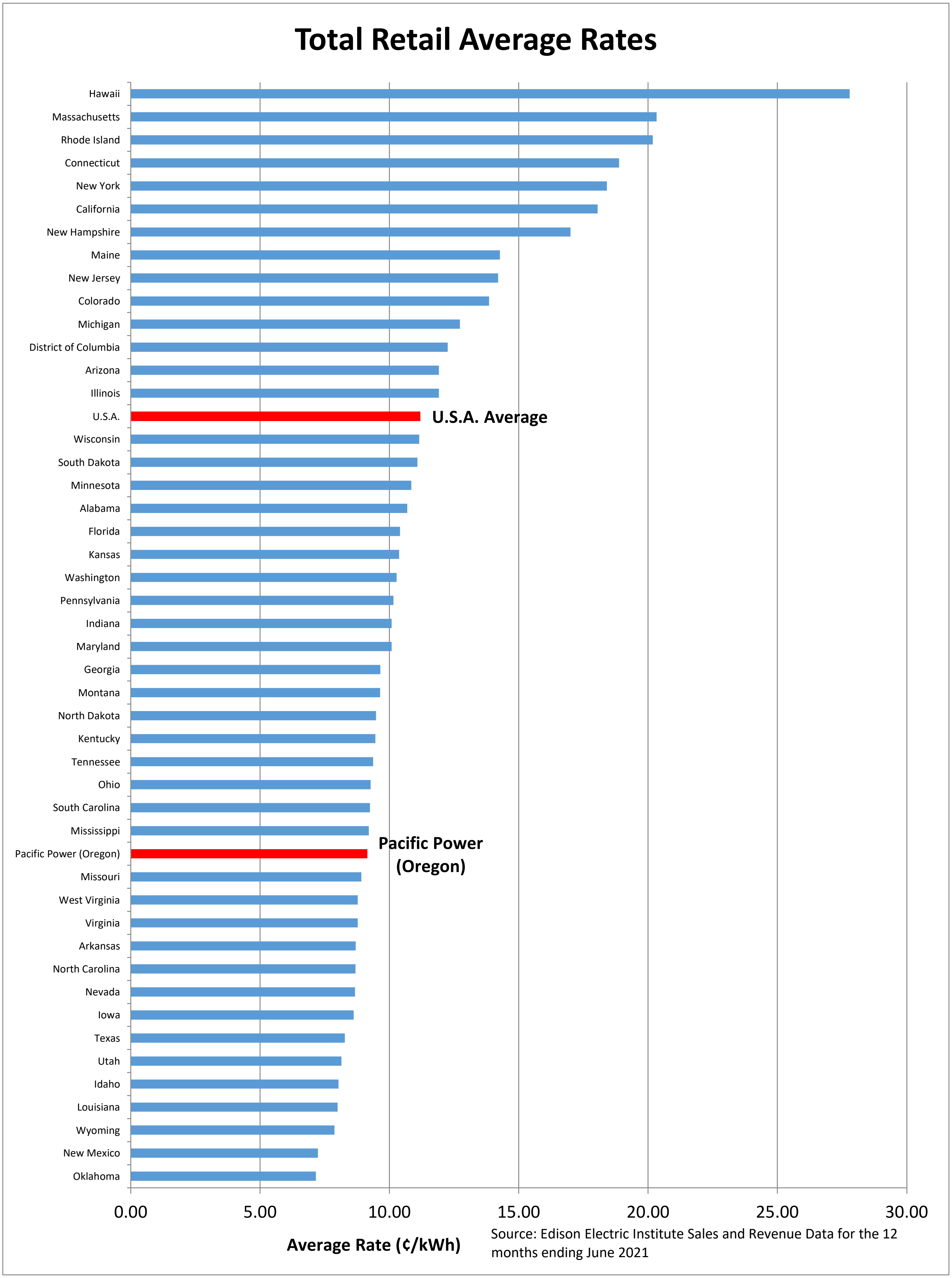
OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Joelle R. Steward

PacifiCorp's Oregon Rates Compared to National Averages

March 2022


Total Retail Average Rates
Hawaii
Massachusetts
Rhode Island
Connecticut
New York
California
New Hampshire
Maine
New Jersey
Colorado
Michigan
District of Columbia
Arizona
Illinois
U.S.A.
U.S.A. Average
Wisconsin
South Dakota
Minnesota
Alabama
Florida
Kansas
Washington
Pennsylvania
Indiana
Maryland
Georgia
Montana
North Dakota
Kentucky
Tennessee
Ohio
South Carolina
Mississippi
Pacific Power (Oregon)
Pacific Power (Oregon)
Missouri
West Virginia
Virginia
Arkansas
North Carolina
Nevada
Iowa
Texas
Utah
Idaho
Louisiana
Wyoming
New Mexico
Oklahoma
0.00
5.00
10.00
15.00
20.00
25.00
30.00
Average Rate (¢/kWh)
Source: Edison Electric Institute Sales and Revenue Data for the 12 months ending June 2021

REDACTED
Docket No. UE 399
Exhibit PAC/200
Witness: Nikki L. Kobliha

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Direct Testimony of Nikki L. Kobliha

March 2022

TABLE OF CONTENTS

ATTACHED EXHIBITS

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 Nikki L. Kobliha and my business address is 825 NE Multnomah Street, Suite 1900, Portland, Oregon 97232. I am currently employed as Vice President, Chief Financial Officer and Treasurer for PacifiCorp.

Q. Please describe your education and professional experience.

A. I received a Bachelor of Business Administration with a concentration in Accounting from the University of Portland in 1994. I became a Certified Public Accountant in 1996. I joined PacifiCorp in 1997 and have taken on roles of increasing responsibility before being appointed Chief Financial Officer in 2015. I am responsible for all aspects of PacifiCorp's finance, accounting, income tax, internal audit, Securities and Exchange Commission reporting, treasury, credit risk management, pension, and other investment management activities.

II. SUMMARY AND PURPOSE OF TESTIMONY

Q. Please summarize the purpose of your testimony.

A. My testimony supports PacifiCorp's overall cost of capital recommendation and addresses pension settlement accounting.

Q. What is the purpose of each of the items summarized above?

A. Regarding the overall cost of capital recommendation, I sponsor the Company's proposed capital structure with a common equity level of 52.25 percent and provide evidence demonstrating why that level is appropriate and benefits customers.

I explain why the 50/50 capital structure ordered in the last general rate case, docket UE 374 (2021 Rate Case)[1] is not a balanced outcome, and how the recommended common equity ratio is required to maintain PacifiCorp's current credit ratings. Strong credit ratings provide for a more competitive cost of debt and overall cost of capital and facilitate continued access by the Company to the capital markets over the long term, which includes times when the capital markets are stable and there is ample liquidity, but also when the capital markets are unstable and liquidity is tight and expensive. The recommended capital structure enables the Company's continued investment in infrastructure to provide safe and reliable service from clean energy resources at reasonable costs. I also support PacifiCorp's proposed cost of long-term debt of 4.38 percent and cost of preferred stock of 6.75 percent.

Regarding pension settlement accounting, I will explain the Company's recent pension settlement loss related activities and treatment thereof in this filing.

Q. What overall cost of capital do you recommend for PacifiCorp?

A. PacifiCorp proposes an overall cost of capital of 7.21 percent. This cost includes the return on equity recommendation of 9.80 percent as supported by the direct testimony of Ms. Ann E. Bulkley and the capital structure and costs set forth in Table 1.

[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).

Table 1: Overall Cost of Capital

Component	$m	% of Total	Cost %	Wtd Ave Cost %
Long-Term Debt	$9,989	47.74 %	4.38 %	2.09 %
Preferred Stock	2	0.01 %	6.75 %	— %
Common Stock Equity	10,933	52.25 %	9.80 %	5.12 %
	$20,924	100.00 %		7.21 %

Q. What time period does your analysis cover?

A. The capital structure for the Company is measured over the calendar year 2023 test period (Test Period) used in this proceeding using an average of the five quarter-ending balances spanning the 12-month period ending December 31, 2023, based on known and measurable changes through December 31, 2023. Similarly, the costs of the long-term debt and preferred stock are an average of the costs measured for each of the five quarter-ending balances spanning the Test Period, using the Company's actual costs adjusted for known and measurable changes through December 31, 2023.

III. DISCUSSION OF RECENTLY ORDERED CAPITAL STRUCTURE

Q. As indicated in the 2021 Rate Case order the Commission found "…a more balanced capital structure serves to reduce the cost of equity to customers, without jeopardizing the financial integrity of the company. We find that a 50 percent equity achieves that balance."[2] Do you agree a 50.00 percent common equity level results in a balanced outcome at this time?

A. No, because a 50.00 percent common equity level does not consider the significant capital growth cycle the Company is in as it expands its renewable portfolio and associated transmission. The need for low-cost debt financing is critical at this time

[2] Order No. 20-473 at 25.

as the Company will be accessing the capital markets numerous times over the next several years. The 52.25 percent proposed common equity level will enable the Company to maintain its credit ratings and issue debt at favorable rates, even if market conditions become unstable, keeping costs low for customers. The last several years have demonstrated that a five-quarter average common equity level near the proposed 52.25 percent common equity level is needed in order to maintain the Company's financial integrity. The Company's projected average percentage capital structures in 2022 and 2023 continue at levels consistent with the past, all of which are in excess of the 50.00 percent capital structure ordered in the 2021 Rate Case.

The referenced capital structures are found in Table 2 below.

Table 2: Forecast and Actual Capital Structures

	Dec 31, 2023 Forecast*	Dec 31, 2022 Forecast*	Dec 31, 2021 Actual*	Dec 31, 2020 Actual*	Dec 31, 2019 Actual*	2021 Rate Case Capital Structure
Long-Term Debt	47.74%	46.95%	47.69%	48.49%	48.36%	49.99%
Preferred Stock	0.01%	0.01%	0.01%	0.01%	0.02%	0.01%
Common Equity	52.25%	53.04%	52.30%	51.50%	51.62%	50.00%
Totals	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

* Five quarter-end average % Capital Structure calculated for trailing 12 month period ending December 31, 2023

If PacifiCorp were to re-balance its capital structure to reflect the 50.00 percent common equity component ordered by the Commission, PacifiCorp would issue approximately $1.8 billion of debt and pay dividends totaling $1.9 billion to its parent company Berkshire Hathaway Energy Company (BHE) in 2022. The increased debt would reduce PacifiCorp's Cash from Operations pre-Working Capital (CFO pre-W/C) to Debt ratio to [redacted] and jeopardize its financial integrity [redacted]

[redacted], which is inconsistent with its current financial profile.

Moody's recently issued credit opinion for PacifiCorp notes that:

> The stable outlook incorporates our expectation that PacifiCorp will continue to receive reasonable regulatory treatment, and that funding requirements will be financed in a manner consistent with management's commitment to maintain a healthy financial profile.
>
> ...The ratings could be downgraded if PacifiCorp's capital expenditures are funded in a manner inconsistent with its current financial profile, or if adverse regulatory rulings lower its credit metrics, as demonstrated for example, by a ratio of CFO pre-WC to debt remaining below 19%.[3]

Furthermore, the Commission's ordered 4.774 percent cost of long-term debt was based on PacifiCorp maintaining its current A rating and as noted above, moving to a 50.00 percent common equity component would result in credit metrics that do not support an A rating and would most likely result in a ratings downgrade. This was not a balanced outcome as the Commission provided customers with the benefit of the lower capital structure but did not adjust rates for the higher cost of debt that would occur with a lower credit rating, and disregarded the financial risk to PacifiCorp from having a lower credit rating in the midst of a significant and sustained capital build cycle.

As provided in Table 3 below, in periods of significant and sustained capital spending the 19.0 percent CFO pre-W/C to debt ratio was not maintained at equity levels in excess of 50.00 percent indicating a higher level is needed during this period.

[3] Moody's Credit Opinion, *PacifiCorp Update to Credit Analysis* (June 30, 2021), at 2.

Table 3: Comparison of Capital Spend and Moody's CFO pre-W/C to Debt Ratio

	2017	2018	2019	2020	2021	2022	2023	2024
	Actual	**Actual**	**Actual**	**Actual**	**Actual**	**Forecast**	**Forecast**	**Forecast**
CAPEX ($m)	$769	$1,257	$2,175	$2,540	$1,513	$2,001	$3,317	$2,501
CFO pre-W/C to Debt	23.0%	21.9%	18.4%	16.7%	[redacted]	[redacted]	[redacted]	[redacted]
Equity %	51.5%	52.1%	51.6%	51.5%	52.3%	53.0%	52.3%	52.5%

*Forecast metric

The significant and sustained capital spending is required 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).[4]

Q. In the 2021 Rate Case Order, the Commission noted "The company did not address, however, how the savings associated with the lower cost of debt compared to the higher costs of an increased equity ratio."[5] Please explain how much the cost of debt would need to increase to offset the higher cost of equity at the Company's proposed capital structure.

A. The overall cost of capital using the Company's proposed 52.25 percent common equity is 7.21 percent while use of a Commission ordered hypothetical 50.00 percent common equity results in a cost of capital of 7.09 percent. Later in my testimony I demonstrate the Company's cost of debt would be 4.84 percent had the Company not had its current single A rating, or a 46 basis point cost of debt increase. Using the 46 basis point higher debt rate with a Commission ordered hypothetical capital structure would have increased the cost of capital to 7.32 percent. The thicker equity needed to maintain the Company's credit rating

[4] *In the Matter of PacifiCorp, dba Pacific Power, 2021 Integrated Resource Plan,* Docket No. LC 77.
[5] Order No. 20-473 at 25.

has kept the overall cost of capital low. An increase of 24 basis points in the Company's cost of debt is the breakeven point between the 52.25 percent proposed capital structure and a 50.00 percent Commission ordered hypothetical capital structure, where the cost of capital in both cases would be 7.21 percent. See Table 4 below.

Table 4: Cost of Capital Comparison

	Proposed	**Hypothetical Capital Structure**	**BBB rated Debt**	**Breakeven Cost of Capital**
Cost of Debt	4.38	4.38	4.84	4.62
Percent Common	52.25	50.00	50.00	50.00
Cost of Capital	7.21	7.09	7.32	7.21

That 24 basis point cost of debt increase can easily occur through normal week-on-week volatility and does not necessarily require severe market instability. A strong credit rating helps insulate the Company from those types of movements and enables continued access to the capital markets in nearly all situations. A strong credit rating can also be thought of as a type of insurance against market volatility and instability. Setting rates using a 12 basis point higher cost of capital (7.21 percent compared to the 7.09 percent), an estimated $5.0 million revenue requirement impact, is a reasonable price to pay considering the 46 basis points savings the Company realized from being single A rated, and to avoid what can be severe cost of debt increases when market volatility or instability occurs, particularly with the level of debt the Company will be issuing in the next several years as the Company works to achieve Oregon's energy policy objectives.

Q. In the 2021 Rate Case the Commission points to other Oregon utilities having a 50/50 capital structure. Is that a fair comparison and justification for PacifiCorp to have a 50/50 capital structure?

A. No. There are a number of factors that support why a one size fits all capital structure is not appropriate. First, while Portland General Electric Company is similarly rated to PacifiCorp, they have a lower credit metric requirement making it easier for them to maintain an A rating. Second, Avista is lower rated resulting in significantly lower credit metric requirements. Third, the aforementioned utilities have different capital expenditure programs driving different financing requirements and the need to access capital markets. This can be seen when comparing the ratio of capital expenditures (CAPEX) to cash from operations (CFO) in Table 5. The Company's largely higher ratio indicates a greater need for debt and equity funding to pay for prudently incurred CAPEX on a least-cost, least-risk basis, including new renewable resources identified in PacifiCorp's 2021 IRP action plan and wildfire mitigation costs.

Table 5: Comparison of Oregon utilities' ratio of CAPEX to CFO

PGE ($,millions)	**2019 Actual**	**2020 Actual**	**2021 Forecast**	**2022 Forecast**	**2023 Forecast**
CAPEX	$ 606	$ 784	$ 655	$ 550	$ 550
CFO[1]	$ 546	$ 567	$ 585	$ 585	$ 585
Ratio - CAPEX to CFO	1.1	1.4	1.1	0.9	0.9

[1] Forecast CFO is based on the average of 2017 through 2020
Source 2019 and 2020 SEC Form 10-K

Avista ($,millions)	**2019 Actual**	**2020 Actual**	**2021 Forecast**	**2022 Forecast**	**2023 Forecast**
CAPEX	$ 443	$ 404	$ 415	$ 405	$ 405
CFO[1]	$ 398	$ 331	$ 375	$ 375	$ 375
Ratio - CAPEX to CFO	1.1	1.2	1.1	1.1	1.1

[1] Forecast CFO is based on the average of 2017 through 2020
Source 2019 and 2020 SEC Form 10-K

PacifiCorp ($,millions)	**2019 Actual**	**2020 Actual**	**2021 Actual**	**2022 Forecast**	**2023 Forecast**
CAPEX	$ 2,175	$ 2,540	$ 1,513	$ 2,001	$ 3,317
CFO[2]	$ 1,547	$ 1,583	$ 1,804	$ 1,669	$ 1,669
Ratio - CAPEX to CFO	1.4	1.6	0.8	1.2	2.0

[2] Forecast CFO is based on the average of 2017 through 2021

Q. Does the Company agree that a 50/50 capital structure is the optimal capital structure for PacifiCorp and strikes a balance between the interest of customers and the interests of investors, particularly during its current build cycle?

A. No. In an effort to maintain credit ratings and low-cost access to debt markets, during this significant and sustained capital build cycle, the Company believes the requested 52.25 percent common equity capital structure is the optimal capital structure at this time. The following quote from a finance textbook written by Roger Morin also supports the Company's current position:

> The optimal capital structure...suggests that long-term achievement of a single A credit rating is in a utility company's and its ratepayers best interests. Debt leverage

> targets should be set in the lower part of the range required to attain this optimal rating. If the company maintains its debt ratio close to the optimal range required for a single A bond rating, its overall cost of capital should be minimized.[6]

PacifiCorp currently has a Moody/Standard & Poor's (S&P) bond issuer credit rating of A3/A, which is considered a single A credit rating, and as suggested from the textbook will minimize its overall cost of capital.

Q. Does a 50.00 percent common equity component allow for economic access to the capital market in uncertain economic times?

A. No. Financial flexibility plays a key role in ensuring liquidity and allowing the Company to meet its funding needs. Higher leverage and a lower credit rating may result in the Company not having access or having to pay significantly more for liquidity. As Moody's states:

> Utilities are among the largest debt issuers in the corporate universe and typically require consistent access to capital markets to assure adequate sources of funding and to maintain financial flexibility. During times of distress and when capital markets are exceedingly volatile and tight, liquidity becomes critically important because access to capital markets may be difficult.[7]

The Company's credit rating must be supported by its capital structure to allow for continuous access to capital even in unfavorable financial market conditions. Given the Company's significant and sustained capital spending, low average retail rates and the potential for uncertain economic times, a stronger balance sheet and higher common equity is warranted.

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[6] Roger A. Morin, PhD, *New Regulatory Finance, Public Utilities Reports*, Inc, Virginia 2006, p.471.
[7] Moody's Sector Comment, *FAQ on credit implications of the coronavirus outbreak* (Mar. 26, 2020), at 1.

IV. FINANCING OVERVIEW

Q. Please explain PacifiCorp's need for and sources of new capital.

A. PacifiCorp requires capital to meet its customers' needs for new cost-effective, transmission and renewable generation, increased reliability, improved power delivery, and safe operations. PacifiCorp also needs new capital to fund long-term debt maturities.

As a result of the 2021 IRP, PacifiCorp expects to spend approximately $6.0 billion (excluding equity allowance for funds used during construction) on renewable energy projects, related transmission, and carbon free generation through calendar year 2026 with $2.8 billion being spent during 2022 and 2023. In addition to the $2.8 billion, PacifiCorp expects to spend approximately $290 million on wildfire mitigation during 2022 and 2023. This significant and sustained level of capital spending will require PacifiCorp to raise funds by issuing new long-term debt in the capital markets, retain earnings, and if needed, obtain new capital contributions from its parent company, BHE. This increase in renewable and carbon free generation and transmission capacity will support PacifiCorp's progress towards acquiring the new renewable resources identified in PacifiCorp's 2021 IRP action plan and ability to meet the energy policy objectives of the state of Oregon on a least-cost, least-risk basis.

Q. How does PacifiCorp finance its electric utility operations?

A. Generally, PacifiCorp finances its regulated utility operations using a mix of debt and common equity capital of approximately 48/52 percent, respectively. During periods of significant and sustained capital expenditures, as expected to continue now through calendar year end 2023 and beyond for the potential new renewable and carbon free generation resources and associated transmission identified in PacifiCorp's 2021 IRP action plan, the Company will need to maintain an average common equity component in excess of 52.00 percent to maintain its credit rating and finance the debt component of the capital structure at the lowest reasonable cost to customers. Maintaining the Company's credit rating will provide more flexibility on the type and timing of debt financing, better access to capital markets, a more competitive cost of debt, and over the long-run, more stable credit ratings. All of these factors assist in financing expenditures like potential new renewable and carbon free generation resources and associated transmission identified in PacifiCorp's 2021 IRP action plan. In addition, PacifiCorp needs a greater common equity component to offset various adjustments that rating agencies make to the debt component of the Company's published financial statements. I discuss these adjustments in greater detail later in my testimony.

Q. How does PacifiCorp determine the levels of common equity, debt, and preferred stock to include in its capital structure?

A. As a regulated public utility, PacifiCorp has a duty and an obligation to provide safe, adequate, and reliable service to customers in its Oregon service area while prudently balancing cost and risk. Major capital expenditures are required in the near-term for new plant investment to fulfill its service obligation, including capital expenditures for new renewable and carbon free generation resources, new transmission, and wildfire mitigation. These capital investments also have associated operating and maintenance costs. As part of its annual business plan process, PacifiCorp reviews all of its estimated cash inflows and outflows to determine the amount, timing, and type of new financing required to support these activities and provide for financial results and credit ratings that balance the cost of capital with continued access to the financial markets.

Q. How does PacifiCorp manage its dividends to BHE?

A. PacifiCorp benefits from its affiliation with BHE as there is no dividend requirement. Historically, PacifiCorp has paid dividends to BHE to manage the common equity component of the capital structure and keep the Company's overall cost of capital at a prudent level. In major and sustained capital investment periods, PacifiCorp is able to retain earnings to help finance capital investments and forgo paying dividends to BHE. For example, following BHE's acquisition of PacifiCorp in 2006, PacifiCorp managed the capital structure through the timing and amount of long-term debt issuances and capital contributions from BHE, while forgoing any common dividends for nearly five years. At other times, absent the payment of dividends, retention of earnings could cause the percentage of common equity to grow beyond the level necessary to support the current credit ratings. Accordingly, dividend payments can be necessary, in combination with debt issuances, to maintain the appropriate percentage of equity in PacifiCorp's capital structure. In 2015, 2016 and 2017 PacifiCorp paid dividends of $950 million, $875 million and $600 million, respectively, and only issued $250 million in long-term debt, due to lower capital spend during this time period. The proposed capital structure in this case anticipates modest common dividend payments by PacifiCorp to BHE of

$300 million in 2022 and $250 million in 2023 and are needed to keep the common equity level at 52.25 percent.

Q. What type of debt does PacifiCorp use in meeting its financing requirements?

A. PacifiCorp has completed the majority of its recent long-term financing using secured first mortgage bonds issued under the Mortgage Indenture dated January 9, 1989. Exhibit PAC/201, Pro Forma Cost of Long-Term Debt, shows that, over the Test Period, PacifiCorp is projected to have an average of approximately $9.8 billion of first mortgage bonds outstanding, with an average cost of 4.43 percent. Presently, all outstanding first mortgage bonds bear interest at fixed rates. Proceeds from the issuance of the first mortgage bonds (and other financing instruments) are used to finance the utility operation.

Another important source of financing in the past has been the tax-exempt financing associated with certain qualifying equipment at power generation plants. Under arrangements with local counties and other tax-exempt entities, these entities issue securities, PacifiCorp borrows the proceeds of these issuances and pledges its credit quality to repay the debt to take advantage of the tax-exempt status of the financing. During the 12 months ending December 31, 2023, PacifiCorp's tax-exempt portfolio is projected to be approximately $185 million, with an average cost of 1.60 percent, including the cost of issuance and remarketing.

A. Credit Ratings

Q. What are PacifiCorp's current credit ratings?

A. PacifiCorp's current ratings are shown in Table 6.

Table 6: PacifiCorp Credit Ratings

	Moody's	Standard & Poor's
Senior Secured Debt	A1	A+
Senior Unsecured Debt	A3	A
Outlook	Stable	Stable

Q. How does the maintenance of PacifiCorp's current credit rating benefit customers?

A. First, the credit rating of a utility has a direct impact on the price that a utility pays to attract the capital necessary to support its current and future operating needs. Many institutional investors have fiduciary responsibilities to their clients and are typically not permitted to purchase non-investment grade (*i.e.*, rated below Baa3/BBB-) securities or in some cases even securities rated below a single A rating. A solid credit rating directly benefits customers by reducing the immediate and future borrowing costs related to the financing needed to support regulatory obligations.

Second, credit ratings are an estimate of the probability of default by the issuer on each rated security. Lower ratings equate to higher risks and higher costs of debt. The Great Recession of 2008–2009 provides a clear and compelling example of the benefits of the Company's credit rating because PacifiCorp was able to issue new long-term debt during the midst of the financial turmoil. Other lower-rated utilities were shut out of the market and could not obtain new capital.

Third, PacifiCorp has a near constant need for short-term liquidity as well as periodic long-term debt issuances. PacifiCorp pays significant amounts daily to suppliers whom we count on to provide necessary goods and services such as fuel, energy, construction services and inventory, and has an active long-term debt portfolio that must be managed for interest payments and maturities. Being unable to access funds can risk the successful completion of necessary capital infrastructure projects and could impact system reliability, customer safety and the ability to meet Oregon's energy policy objectives for carbon free generation on a least-cost, least-risk basis. PacifiCorp's credit facilities may not have the capacity to cover these significant periodic uses of cash and not having access to the market would jeopardize the ability to issue lower rate debt.

PacifiCorp's creditworthiness, as reflected in its credit ratings, will strongly influence its ability to attract capital in the competitive markets and the resulting costs of that capital.

Q. Can you provide an example of how the current ratings have benefited customers?

A. Yes. One example is PacifiCorp's ability to significantly reduce its cost of long-term debt primarily through obtaining new financings at very attractive interest rates. The lower cost of debt benefits customers through a lower overall rate of return and lower revenue requirement.

To determine the savings realized from maintaining a higher credit rating, in Exhibit PAC/203 New Debt Issue Spreads, I compared the actual effective interest rate on the Company's existing as well as pro-forma and repriced long-term debt forecasted to be outstanding during the Test Period, which was issued since its acquisition by BHE in 2006, comprising 18 series of debt, to what the effective interest rate would have been with a BBB credit rating. The issuance spread of each issuance was changed to match what a BBB rated utility achieved at about the same point in time that PacifiCorp issued the debt. The total result for the 18 series of debt averaging $8.9 billion over the test period, would have been an effective average interest rate of approximately 4.74 percent or 52 basis points higher than the actual effective interest rate. Combined with the existing pre-acquisition debt, the resulting overall cost of long-term debt would increase to 4.84 percent if the Company had a BBB rating. PacifiCorp is currently projecting an overall cost of long-term debt of 4.38 percent, or 46 basis points lower than it might have otherwise been under the scenario I described above.

Table 7 below shows the reduction in the Company's cost of long-term debt since 2010.

Table 7: PacifiCorp's Cost of Long-Term Debt

	Dec 2023	UE 374 Dec 2021	UE 263 Dec 2013	UE 246 Dec 2012	UE 217 Dec 2010
Cost of Long-Term Debt	4.38%	4.77%	5.32%	5.37%	5.85%

PacifiCorp's customers have benefited from a 147 basis points (1.47 percent) reduction in the Company's cost of long-term debt. The Company estimates that this reduction in the average cost of debt since 2010 results in a decrease of approximately $31.0 million in the revenue requirement in the current case. Customers have also benefited from the Company's ability to negotiate lower underwriting fees on long-term debt issuances through BHE's global underwriting fee position.

Q. Are there other identifiable advantages to a favorable rating?

A. Yes. Higher-rated companies have greater access to the long-term markets for power purchases and sales. This access provides these companies with more alternatives to meet the current and future load requirements of their customers. Additionally, a company with strong ratings will often avoid having to meet costly collateral requirements that are typically imposed on lower-rated companies when securing power in these markets.

In my opinion, maintaining the current single A rating provides the best balance between costs and continued access to the capital markets, which is necessary to fund capital projects for the benefit of customers.

Q. Please provide examples where poor credit ratings hurt a utility's flexibility in the credit markets.

A. During the Great Recession in 2008, Arizona Public Service Company (rated Baa2/BBB- at that time) filed a letter with the Arizona Corporation Commission in October 2008 stating that the commercial paper market was completely closed to it and it likely could not successfully issue long-term debt.[8]

Further, those issuers who could access the markets paid rates well above the levels that PacifiCorp was able to obtain. For example, PacifiCorp issued new 10-year and 30-year long-term debt in January 2009 with 5.50 percent and 6.00 percent coupon rates, respectively. Subsequently, Puget Sound Energy (rated Baa2/A- at that time) issued new seven-year debt at a credit spread over Treasuries of 480.3 basis points resulting in a 6.75 percent coupon.

Q. Can regulatory actions or orders affect PacifiCorp's credit rating?

A. Yes. Regulated utilities such as PacifiCorp are unique in that they cannot unilaterally set the price for their services. The financial integrity of a regulated

[8] *See* Exhibit PAC/302.

utility is largely a result of the prudence of utility operations and the corresponding prices set by regulators. Rates are established by regulators to permit the utility to recover prudently incurred operating expenses and a reasonable opportunity to earn a fair return on the capital invested.

Rating agencies and investors have a keen understanding of the importance of regulatory outcomes. For example, S&P has opined on the correlation between regulatory outcomes and credit ratings, concluding:

> Although not common, rate case outcomes can sometimes lead directly to a change in our opinion of creditworthiness. Often it's a case that takes on greater importance because of the issues being litigated. For example, in 2010, we downgraded Florida Power & Light and its affiliates following a Florida Public Service Commission rate ruling that attracted attention due to drastic changes to settled practices on rate case particulars like depreciation rates. More recently, in June 2016, we downgraded Central Hudson Electric & Gas due to our revised opinion of regulatory risk. While that reflected the company's own management of regulatory risk, it was prompted in part by other rate case decisions in New York that highlighted the overall risk in the state.[9]

As discussed in the testimony of Ms. Bulkley, Section VIII. B., Regulatory Risk, the regulatory environment and the rate decisions by utility commissions have a direct and significant impact on the financial condition of utilities.

Q. Does PacifiCorp's credit rating benefit because of BHE and its parent Berkshire Hathaway Inc.?

A. Yes. Although ring-fenced, PacifiCorp's credit ratios have been weak for the ratings level. PacifiCorp has been able to sustain its ratings in part through the

[9] S&P Ratings Direct, *Assessing U.S. Investor-Owned Utility Regulatory Environments* (Aug. 10, 2016), at 4.

acquisition by BHE and its parent, Berkshire Hathaway Inc. S&P was very clear on this point in its April 2021 assessment of PacifiCorp:

> Under our group rating methodology, we consider PacifiCorp to be a core subsidiary of BHE with a group credit profile of 'a'. The core status reflects our view that PacifiCorp is highly unlikely to be sold, has strong long-term commitment from senior management, is successful at what it does, and contributes meaningfully to the group. Given its core subsidiary status and BHE's group credit profile of 'a', the issuer credit rating on PacifiCorp is 'A'.[10]

Moody's states in their June 2021 credit opinion of PacifiCorp:

> PacifiCorp benefits from its affiliation with BRK, which requires no regular dividends from PacifiCorp or BHE. From a credit perspective, the company's ability to retain its earnings as an entity that is privately held, particularly by a deep-pocketed sponsor like BRK, is an advantage over most other investor owned utilities that are typically held to a regular dividend to their shareholders. PacifiCorp generally pays dividends that are sized to manage its equity ratio (as measured by unadjusted equity to equity plus long term debt) around its allowed levels of slightly higher than 50% (regulations restrict dividends if this ratio falls below 44%). As of December 2020, PacifiCorp reports its actual equity percentage, as calculated under this test, was 53%.[11]

These examples are evidence of the credit rating benefit resulting from BHE's ownership of PacifiCorp.

B. Rating Agency Debt Imputations

Q. Is PacifiCorp subject to rating agency debt imputation associated with power purchase agreements (PPAs)?

A. Yes. Rating agencies and financial analysts consider PPAs to be debt-like and will impute debt and related interest when calculating financial ratios. For example, S&P will adjust PacifiCorp's published financial results and impute debt balances and interest expense resulting from PPAs when assessing creditworthiness. They do so to obtain a more accurate assessment of a Company's financial commitments and

[10] S&P Ratings Direct, *PacifiCorp* (April 5, 2021), at 9.
[11] Moody's Credit Opinion, PacifiCorp (June 30, 2021) at 8.

fixed payments. S&P Ratings Direct November 19, 2013, details its view of the debt aspects of PPAs and other debt imputations, and is included as Confidential Exhibit PAC/204.

Q. How does this impact PacifiCorp?

A. In its most recent evaluation of PacifiCorp, S&P added approximately $850 million of additional debt and $21 million of related interest expense to the Company's debt and coverage tests for PPAs and other liabilities of the Company that are considered to be debt-like by S&P.

Q. How does inclusion of the PPA-related debt and these other adjustments affect PacifiCorp's capital structure as S&P reviews the Company's credit metrics?

A. Negatively. By including the imputed debt resulting from PPAs and these other adjustments, PacifiCorp's capital structure has a lower equity component as a corollary to the higher debt component, lower coverage ratios, and reduced financial flexibility than what might otherwise appear to be the case from a review of the book value capital structure. For example, as shown in Table 8, if one were to apply the total $850 million amount of debt adjustments that S&P most recently made to PacifiCorp's proposed capital structure in this case, the resulting common equity percentage would decline from 52.25 percent to 50.21 percent. If the Company were to finance at the ordered 50.00 percent, the imputed debt adjustment would drop the equity level below 50.00 percent and increases the risk of a ratings down grade.

Table 8: Rating Agency Adjusted Capital

	Proposed Cap Structure		Rating	Adjusted Cap Structure	
	Book Values	% of Total	Agency Adjustments	Book Values	% of Total
Long-Term Debt	$9,989	47.74%	$850	$10,839	49.78 %
Preferred Stock	2	0.01%	(1)	1	0.01 %
Common Equity	10,933	52.25%	-	10,933	50.21 %
	$20,924	100.00%	$849	$21,773	100.00 %

V. CAPITAL STRUCTURE DETERMINATION

Q. How did the Company determine its recommended capital structure?

A. The capital structure is based on the actual capital structure at December 31, 2021 and forecasted capital activity, including known and measurable changes, through December 31, 2023. PacifiCorp averaged the five quarter-end capital structures measured beginning at December 31, 2022, and concluding with December 31, 2023, resulting in a capital structure with an equity component of 52.25 percent. The support for these five quarter-end capital structures, spanning the 12-month test period, are provided by the Company in response to Standard Data Request 38 in this general rate case docket. The capital activity includes known maturities of certain debt issues that were outstanding at December 31, 2021, subsequent issuances of long-term debt, and any capital contributions received or dividends paid. The known and measurable changes represent forecasted capital activity since December 31, 2021.

Q. Why does the Company propose a capital structure calculated using a five-quarter average?

A. This approach smooths volatility in the capital structure, which will fluctuate as the Company expends capital, issues or retires debt, retains earnings, or declares dividends.

Q. Why is PacifiCorp using capital balances for the 12-month period ending December 31, 2023, rather than the projected capital structure as of the rate effective date?

A. This approach best captures the actual capital structure PacifiCorp forecasts for the rate effective period.

Q. How does the Company's proposed capital structure compare to the equity ratio of the utility operating company proxy group found in Exhibit PAC/303 of Ms. Bulkley's testimony?

A. Ms. Bulkley's exhibit shows the low, high and median of the proxy group average equity ratios are 46.85 percent, 61.11 percent and 52.71 percent, respectively. The Company's proposed capital structure is well within this range.

VI. COST CALCULATIONS

Q. How did you calculate the Company's embedded costs of long-term debt and preferred stock?

A. Consistent with my determination of the percentage capital structure discussed previously, I have similarly calculated the embedded costs of debt and preferred stock as an average of the five quarter-end cost calculations spanning the test period, beginning at December 31, 2022, and concluding with December 31, 2023.

Q. Please explain the cost of long-term debt calculation.

A. I calculated the cost of debt by issue, based on each debt series' interest rate and net proceeds at the issuance date, to produce a bond yield to maturity for each series of debt outstanding as of each of the five quarter-ending dates spanning the Test Period. It should be noted that in the event a bond was issued to refinance a higher cost bond, the pre-tax premium and unamortized costs, if any, associated with the refinancing were subtracted from the net proceeds of the bonds that were issued. Each bond yield was then multiplied by the principal amount outstanding of each debt issue, resulting in an annualized cost of each debt issue. Aggregating the annual cost of each debt issue produces the total annualized cost of debt. Dividing the total annualized cost of debt by the total principal amount of debt outstanding produces the weighted average cost for all debt issues. The support for each of these pro-forma weighted average cost of debt calculations as of each of the five quarter-ending dates spanning the Test Period are provided as attachments by the Company in response to Standard Data Request 12. The average of these-five annualized cost of debt calculations, as summarized below, is PacifiCorp's embedded cost of long-term debt for this proceeding:

Table 9: PacifiCorp Embedded Cost of Long-Term Debt

	Forecast LT Debt O/S ($m)	Wt Ave Pro-forma Cost of LT Debt	Cost of Debt calcs provided in response to OR GRC SDR 12
12/31/22	$ 9,442	4.45%	attach SDR 12-2
03/31/23	9,433	4.46%	attach SDR 12-3
06/30/23	10,433	4.31%	attach SDR 12-4
09/30/23	10,341	4.33%	attach SDR 12-5
12/31/21	10,293	4.36%	attach SDR 12-6
5QE Ave	$ 9,989	4.38%	

Q. Please describe the changes to the amount of outstanding long-term debt between December 31, 2021, and December 31, 2023?

A. Approximately $604 million of the Company's fixed rate long-term debt, respectively, will mature during this period and I have therefore repriced or removed this debt when appropriate in the determination of the proposed average cost of debt. Also, as reflected in Exhibit PAC/201, Pro forma Cost of Long-Term Debt, the Company anticipates new fixed rate long-term debt during the period, a 30-year term issuance of $800 million in 2022 and a 10- and 30-year split term issuance totaling $1,300 million in 2023.

Q. Regarding the $800 million of new long-term issuances in 2022, how did you determine the interest rate and resulting cost for this new long-term debt?

A. The Company's current estimated credit spread for 30-year debt is 1.20 percent and the recent forward 30-year U.S. Treasury rates for September 2022 is approximately 2.12 percent. Issuance costs for 30-year debt of this type adds approximately 0.05 percent to the all-in cost. Therefore, as reflected in Exhibit PAC/201, Pro

Forma Cost of Long-Term Debt, the Company projects a total all-in cost of long-term debt of 3.37 percent, for the projected new 30-year long-term debt.

Q. Regarding the $1.3 billion of new long-term issuances in 2023, how did you determine the interest rate and resulting cost for this new long-term debt?

A. The Company's current estimated credit spread for 10-year and 30-year debt is 0.90 and 1.20 percent, respectively. The recent forward 10-year and 30-year U.S. Treasury rates for May 2023 are approximately 1.95 and 2.15 percent, respectively. Issuance costs for 10-year and 30-year debt of this type adds approximately 0.08 and 0.05 percent to the all-in cost, respectively. Therefore, as reflected in Exhibit PAC/201, Pro Forma Cost of Long-Term Debt, the Company projects a total all-in cost of long-term debt of 2.93 percent and 3.40 percent, respectively, for the projected new 10-year and 30-year long-term debt.

Q. A portion of the securities in PacifiCorp's debt portfolio bears variable rates. What is the basis for the projected interest rates used by PacifiCorp?

A. The Company's variable rate long-term debt in this case is in the form of tax-exempt debt. Exhibit PAC/205, Indicative Forward Pollution Control Revenue Bonds Variable Rates, shows that, on average, these securities have been trading at approximately 85 percent of the 30-day London Inter Bank Offer Rate (LIBOR) for the period January 2000 through December 2021. Therefore, the Company has applied a factor of 85 percent to the forward Bloomberg 1-Month Short Term Bank Yield Index (USD) rate as of each of the five quarter-ending dates spanning the Test Period and then added the respective credit facility and remarketing fees for each floating rate tax-exempt bond outstanding during the period. Credit facility and remarketing fees are included in the interest component because these are costs which contribute directly to the interest rate on the securities and are charged to interest expense. This method is consistent with the Company's past practices when determining the cost of debt in previous Oregon general rate cases as well as in other states that regulate PacifiCorp.

Q. Did you make any further adjustments in your pro-forma calculations of the Company's weighted cost of debt over the Test Period?

A. Yes. For the pro-forma weighted average cost of debt calculations made for each of the five quarter-ending dates spanning the Test Period, as evidenced in the attachments provided by the Company in response to Standard Data Request 12, I adjusted the interest rate on the then existing long-term debt scheduled to mature within one year to reflect expected financing rates. This adjustment is consistent with the Commission practice as set forth in Order 01-787[12] and with the Company's practice in cases since that order.

Q. How did you calculate the embedded cost of preferred stock?

A. The embedded cost of preferred stock was calculated by first determining the cost of money for each issue. I began by dividing the annual dividend per share by the per share net proceeds for each series of preferred stock. The resulting cost rate associated with each series was then multiplied by the total par or stated value outstanding for each issue to yield the annualized cost for each issue. The sum of annualized costs for each issue produces the total annual cost for the entire preferred stock portfolio. I then divided the total annual cost by the total amount of

[12] *In the matter of PacifiCorp's Proposal to Restructure and Reprice its Services in Accordance with the Provisions of SB 1149*, Docket No. UE 116, Order No. 01-787 (Sept. 7, 2001).

preferred stock outstanding to produce the weighted average cost for all issues. The result is PacifiCorp's embedded cost of preferred stock.

A. Embedded Cost of Long-Term Debt

Q. What is PacifiCorp's embedded cost of long-term debt?

A. The cost of long-term debt is 4.38 percent, as shown in Exhibit PAC/201, Pro forma Cost of Long-Term Debt.

B. Embedded Cost of Preferred Stock

Q. What is PacifiCorp's embedded cost of preferred stock?

A. Exhibit PAC/206, Cost of Preferred Stock, shows the embedded costs of preferred stock to be 6.75 percent.

VII. PENSION COSTS

Q. Please provide a brief overview of pension costs and pension settlement accounting.

A. The Company incurs net periodic benefit costs for its defined benefit pension plans each year based on calculations performed by its actuaries in accordance with Financial Accounting Standards Board's Accounting Standards Codification Topic 715-30—Compensation—Retirement Benefits (ASC 715). The Company's net periodic benefit cost includes the ASC 715 components of interest cost and amortization of unrecognized net actuarial losses offset by expected returns on plan assets. Due to the frozen status of the Company's pension plans, the ASC 715 service cost component is zero.

In the event lump sum distributions to retirees in a calendar year exceed the service cost plus interest cost threshold set forth in ASC 715, settlement accounting is triggered. (Due to service cost being zero for the Company's pension plans, the threshold is simply interest cost). This results in accelerated recognition of a portion of unrecognized net actuarial losses that are otherwise amortized over the average remaining lives of plan participants through normal net periodic benefit cost under ASC 715. Absent recovery of the settlement loss being probable of recovery (in which case the loss would be deferred to a regulatory asset), the settlement loss is required to be immediately charged to expense under ASC 715. As indicated, the settlement loss is not incremental to expense that would have otherwise been recognized; rather it is simply a timing difference.

For further details regarding pension settlement accounting and the Company's pension plans, please refer to my direct testimony in docket UE 374 Exhibit PAC/300.

Q. Has the Company filed a deferral request as a result of pension settlement losses since the Commission issued its order in the Company's 2021 Rate Case and if so, what was the rationale for such a filing?

A. Yes. On July 27, 2021, the Company filed an application for a deferred accounting and accounting order related to its defined benefit plans.[13] This application was filed in anticipation of reaching the settlement accounting threshold at the end of July 2021 and on the basis of the Commission's order in the Company's 2021 Rate Case, which states in part:

> We will consider a request by the company to address a pension settlement loss occurring during the test year, in the event it occurs, but would expect such a filing to address the concerns noted above,

[13] *In the Matter of PacifiCorp dba Pacific Power Application for Approval of Deferred Accounting and Accounting Order Related to Non-Contributory Defined Benefit Pension Plans*, Docket No. UM 2185, Application filed July 27, 2021.

> regarding a potential for over-recovery, as well as certain other considerations discussed below. We recognize that without a deferral order in place, if the company does incur a pension settlement loss in the test year, it may have to be expensed.[14]

Q. In its application, how did the Company address the Commission's concern regarding the potential over-recovery quoted in the excerpt above?

A. The Company proposed that upon triggering of a settlement loss, amortization begin immediately over the average remaining lives of plan participants in order to align with the amortization component of net period benefit cost reflected in revenue requirement in the Company's 2021 Rate Case. This approach eliminates the concern of potential double recovery since no rate change would occur between the point of the settlement loss being triggered and the Company's next general rate case, yet the Company would continue to amortize the losses at a level similar to that already reflected in base rates.

Q. What is the status of docket UM 2185 and what is being proposed in this filing?

A. As there has been no activity on docket UM 2185, the Company proposes the application be addressed through this filing, and thus I will address the 2021 settlement loss activity in my testimony. Please see Ms. Joelle R. Steward's testimony for a discussion of the Company's motion to consolidate various open deferral proceedings.

Q. Please provide an update regarding pension settlement losses that occurred in the 2021 test period of the Company's 2021 Rate Case.

A. As indicated in the Company's application in docket UM 2185, settlement accounting was expected to be triggered at July 31, 2021. At that date, lump sum

[14] Order No. 20-473 at 95.

distributions totaled $28.823 million and exceeded the settlement loss accounting threshold of $26.097 million. As a result, an interim remeasurement of the plan assets and benefit obligation occurred and an $8.947 million settlement loss was recognized. The plan assets and benefit obligation were again remeasured at December 31, 2021 and an additional $6.699 million settlement loss was recognized. Thus, on a total-company basis, pension settlement losses totaled $15.646 million in 2021.

Q. Please describe the Company's accounting for Oregon's share of the 2021 settlement losses and in particular how the Commission's concern regarding potential double recovery was addressed.

A. For each of the July 31, 2021 and December 31, 2021 settlement losses, the Company deferred Oregon's system-allocated share to a regulatory asset with amortization over the approximately 20-year average remaining life expectancy of plan participants beginning immediately (i.e., effective August 1, 2021 for the July loss and January 1, 2022 for the December loss). As a result, amortization of these losses approximates what is currently reflected in base rates from the Company's 2021 Rate Case. This treatment is consistent with the Commission's Order in the Company's 2021 Rate Case, which states in part:

> We also note that PacifiCorp, would however, continue to recover through base rates an amount for FAS 87 pension expense that is unadjusted for that settlement loss, even though, all else held equal, its actual pension expense after 2021 would be reduced by the accelerated recognition of this expense. In this way, the company will still recover a portion of that accelerated expense over time, until rates are reset in a future case or some other regulatory action were taken. If the company makes a future request to defer a pension

> settlement loss in the test year, we expect the company's proposal would account for this dynamic.[15]

Due to the proximity of the 2021 settlement losses to the timing of when base rates reset, and with a similar level of amortization reflected in base rates, the Company deferred the 2021 settlement losses to a regulatory asset.

Q. How have the 2021 pension settlement losses been reflected in this filing?

A. Based on the above-described accounting for the 2021 settlement losses, approximately 1/20th of those losses is included in the forecast Test Period pension cost.

Q. Please describe any additional pension settlement loss related activity projected after 2021 and how such amounts, if any, are reflected in this filing.

A. The Company's actuaries have projected settlement losses of $9.781 million and $7.145 million in 2022 and 2023, respectively, with the threshold assumed to be surpassed at the end of the respective year and amortization beginning immediately. Thus, approximately 1/20th of the $9.781 million projected 2022 settlement loss is included in the forecast Test Period pension cost. Due to the 2023 settlement loss assumed to occur at year-end, no specific amortization or recognition of that loss is included in the forecast Test Period pension cost; rather, the associated unrecognized loss is included in the forecast Test Period expense based on the normal amortization component of net periodic pension cost. This approach to the projected 2022 and 2023 settlements losses is also consistent with the Commission's Order in the Company's 2021 Rate Case quoted above.

[15] Order No. 20-473 at 95-96.

VIII. CONCLUSION

Q. Please summarize your recommendations to the Commission.

A. I respectfully request the Commission adopt PacifiCorp's proposed capital structure with a common equity level of 52.25 percent. This capital structure balances the financial integrity of the Company and costs to customers by reflecting the minimum equity ratio necessary for PacifiCorp to maintain its ratings under current market conditions. When combined with PacifiCorp's updated cost of long-term debt of 4.38 percent and the cost of equity of 9.80 percent recommended by Ms. Bulkley, this produces a reasonable overall cost of capital of 7.21 percent.

I also respectfully request the Commission accept the Company's 2021 actual pension settlement losses and projected 2022 pension settlement loss in base rates by allowing them to be amortized over the average remaining lives of plan participants (approximately 20 years) as reflected in the Company's revenue requirement in this filing.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 399
Exhibit PAC/201
Witness: Nikki L. Kobliha

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Nikki L. Kobliha

Pro forma Cost of Long-Term Debt

March 2022

PACIFICORP
Electric Operations
Pro Forma Ave Cost of Long-Term Debt Summary
12 months ended December 31, 2023

LINE NO.	DESCRIPTION	AMOUNT 5QE AVE OUTSTANDING	(DISC)/PREM & ISSUANCE EXPENSES	REDEMPTION EXPENSES	NET PROCEEDS TO COMPANY	ANNUAL DEBT SERVICE COST	INTEREST RATE	ALL-IN COST	ORIG LIFE	LINE NO.
1										1
2	**Total First Mortgage Bonds**	**$9,803,690,000**	**($111,131,695)**	**($2,073,225)**	**$9,690,485,080**	**$434,218,750**	**4.351%**	**4.429%**	**27.0**	2
3										3
4	Subtotal - Pollution Control Revenue Bonds secured by FMBs	$160,460,000	($3,962,932)	($1,745,495)	$154,751,573	$2,584,931	1.461%	1.611%	30.0	4
5	Subtotal - Pollution Control Revenue Bonds	$24,400,000	($225,000)	($428,469)	$23,746,531	$373,076	1.417%	1.529%	29.9	5
6	**Total Pollution Control Revenue Bonds**	**$184,860,000**	**($4,187,932)**	**($2,173,964)**	**$178,498,103**	**$2,958,007**	**1.455%**	**1.600%**	**29.9**	6
7										7
8	Loss on Long Term Debt Reacquistions, without Refunding					$205,126				8
9	**Total Cost of Long Term Debt**	**$9,988,550,000**	**($115,319,627)**	**($4,247,189)**	**$9,868,983,183**	**$437,381,884**	**4.297%**	**4.379%**	**27.0**	9
10										10

PACIFICORP
Electric Operations
Pro Forma Ave Cost of Long-Term Debt Detail
12 months ended December 31, 2023

LINE NO.	INTEREST RATE	DESCRIPTION	ISSUANCE DATE	MATURITY DATE	ORIG LIFE	PRINCIPAL AMOUNT ORIGINAL ISSUE	PRINCIPAL AMOUNT 5QE AVE OUTSTANDING	(DISC)/PREM & ISSUANCE EXPENSES	REDEMPTION EXPENSES	NET PROCEEDS TO COMPANY TOTAL DOLLAR AMOUNT	NET PROCEEDS TO COMPANY PER $100 PRINCIPAL AMOUNT	MONEY TO COMPANY	ANNUAL DEBT SERVICE COST	LINE NO.
	(a)	(b)	(c)	(d)	(e)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
1														1
2														2
3	3.600%	Series due Apr 2024	03/13/14	04/01/24	10	$425,000,000	$170,000,000	($1,440,066)	($777,230)	$167,782,705	$98.696	3.757%	$6,386,900	3
4	3.350%	Series due Jul 2025	06/19/15	07/01/25	10	$250,000,000	$250,000,000	($2,441,421)	$0	$247,558,579	$99.023	3.466%	$8,665,000	4
5	3.500%	Series due Jun 2029	03/01/19	06/15/29	10	$400,000,000	$400,000,000	($2,874,181)	$0	$397,125,819	$99.281	3.584%	$14,336,000	5
6	2.700%	Series due Sep 2030	04/08/20	09/15/30	10	$400,000,000	$400,000,000	($2,876,791)	$0	$397,123,209	$99.281	2.780%	$11,120,000	6
7	7.700%	Series due Nov 2031	11/21/01	11/15/31	30	$300,000,000	$300,000,000	($3,701,310)	$0	$296,298,690	$98.766	7.807%	$23,421,000	7
8	2.846%	Proforma Series#2	05/15/23	05/15/33	10	$650,000,000	$390,000,000	($2,698,320)	$0	$387,301,680	$99.308	2.926%	$11,411,400	8
9	5.900%	Series due Aug 2034	08/24/04	08/15/34	30	$200,000,000	$200,000,000	($2,614,365)	$0	$197,385,635	$98.693	5.994%	$11,988,000	9
10	5.250%	Series due Jun 2035	06/08/05	06/15/35	30	$300,000,000	$300,000,000	($3,992,021)	($1,295,995)	$294,711,984	$98.237	5.369%	$16,107,000	10
11	6.100%	Series due Aug 2036	08/10/06	08/01/36	30	$350,000,000	$350,000,000	($4,048,881)	$0	$345,951,119	$98.843	6.185%	$21,647,500	11
12	5.750%	Series due Apr 2037	03/14/07	04/01/37	30	$600,000,000	$600,000,000	($613,216)	$0	$599,386,784	$99.898	5.757%	$34,542,000	12
13	6.250%	Series due Oct 2037	10/03/07	10/15/37	30	$600,000,000	$600,000,000	($5,877,281)	$0	$594,122,719	$99.020	6.323%	$37,938,000	13
14	6.350%	Series due Jul 2038	07/17/08	07/15/38	30	$300,000,000	$300,000,000	($3,961,333)	$0	$296,038,667	$98.680	6.450%	$19,350,000	14
15	6.000%	Series due Jan 2039	01/08/09	01/15/39	30	$650,000,000	$650,000,000	($12,309,687)	$0	$637,690,313	$98.106	6.139%	$39,903,500	15
16	4.100%	Series due Feb 2042	01/06/12	02/01/42	30	$300,000,000	$300,000,000	($3,724,911)	$0	$296,275,089	$98.758	4.173%	$12,519,000	16
17	4.125%	Series due Jan 2049	07/13/18	01/15/49	31	$600,000,000	$600,000,000	($6,984,085)	$0	$593,015,915	$98.836	4.193%	$25,158,000	17
18	4.150%	Series due Feb 2050	03/01/19	02/15/50	31	$600,000,000	$600,000,000	($7,938,771)	$0	$592,061,229	$98.677	4.227%	$25,362,000	18
19	3.300%	Series due Mar 2051	04/08/20	03/15/51	31	$600,000,000	$600,000,000	($10,127,937)	$0	$589,872,063	$98.312	3.388%	$20,328,000	19
20	2.900%	Series due June 2052	07/09/21	06/15/52	31	$1,000,000,000	$1,000,000,000	($16,597,874)	$0	$983,402,126	$98.340	2.982%	$29,820,000	20
21	3.324%	Proforma Series#1	09/15/22	09/15/52	30	$800,000,000	$800,000,000	($7,250,400)	$0	$792,749,600	$99.094	3.373%	$26,984,000	21
22	3.349%	Proforma Series#3	05/15/23	05/15/53	30	$650,000,000	$390,000,000	($3,478,320)	$0	$386,521,680	$99.108	3.396%	$13,244,400	22
23	3.366%	Series - Cur Mat LT Debt (repriced)	12/31/23	12/31/53	30		$503,690,000	($4,676,059)	$0	$499,013,941	$99.072	3.416%	$17,206,050	23
24	**4.326%**	**Subtotal - Bullet FMBs**			**27**		**$9,703,690,000**	**($110,227,228)**	**($2,073,225)**	**$9,591,389,547**		**4.405%**	**$427,437,750**	24
25														25
26														26
27	6.710%	Series G due Jan 2026	01/23/96	01/15/26	30	$100,000,000	$100,000,000	($904,467)	$0	$99,095,533	$99.096	6.781%	$6,781,000	27
28	**6.710%**	**Subtotal - Series G MTNs**			**30**		**$100,000,000**	**($904,467)**	**$0**	**$99,095,533**		**6.781%**	**$6,781,000**	28
29														29
30	**4.351%**	**Total First Mortgage Bonds**			**27**		**$9,803,690,000**	**($111,131,695)**	**($2,073,225)**	**$9,690,485,080**		**4.429%**	**$434,218,750**	30
31														31
32														32
33	1.473%	Converse 94 due Nov 2024	11/17/94	11/01/24	30	$8,190,000	$6,552,000	($167,822)	($69,058)	$6,315,119	$96.385	1.626%	$106,536	33
34	1.427%	Emery 94 due Nov 2024	11/17/94	11/01/24	30	$121,940,000	$97,552,000	($2,619,397)	($1,540,614)	$93,391,990	$95.736	1.607%	$1,567,661	34
35	1.610%	Lincoln 94 due Nov 2024	11/17/94	11/01/24	30	$15,060,000	$12,048,000	($338,286)	($65,142)	$11,644,572	$96.651	1.754%	$211,322	35
36	1.510%	Sweetwater 94 due Nov 2024	11/17/94	11/01/24	30	$21,260,000	$17,008,000	($408,383)	($70,682)	$16,528,935	$97.183	1.629%	$277,060	36
37	1.398%	Converse 95 due Nov 2025	11/17/95	11/01/25	30	$5,300,000	$5,300,000	($105,635)	$0	$5,194,365	$98.007	1.481%	$78,493	37
38	1.501%	Lincoln 95 due Nov 2025	11/17/95	11/01/25	30	$22,000,000	$22,000,000	($323,409)	$0	$21,676,591	$98.530	1.563%	$343,860	38
39	**1.461%**	**Subtotal - Secured PCRBs**			**30**		**$160,460,000**	**($3,962,932)**	**($1,745,495)**	**$154,751,573**		**1.611%**	**$2,584,931**	39
40														40
41	1.417%	Sweetwater 95 due Nov 2025	12/14/95	11/01/25	30	$24,400,000	$24,400,000	($225,000)	($428,469)	$23,746,531	$97.322	1.529%	$373,076	41
42	**1.417%**	**Subtotal - Unsecured PCRBs**			**30**		**$24,400,000**	**($225,000)**	**($428,469)**	**$23,746,531**		**1.529%**	**$373,076**	42
43														43
44	**1.455%**	**Total PCRB Obligations**			**30**		**$184,860,000**	**($4,187,932)**	**($2,173,964)**	**$178,498,103**		**1.600%**	**$2,958,007**	44
45														45
46			**REACQ**	**ORG MAT**										46
47			**DATE**	**DATE**										47
48		8.375% Series A QUIDS	11/17/00	06/30/35									$107,887	48
49		8.55% Series B QUIDS	11/17/00	12/31/25									$84,084	49
50		Carbon '94 PCRB Series	02/18/16	11/01/24									$13,155	50
51		**Long-Term Debt Reacquisition, without refunding amortization**											**$205,126**	51
52														52

PACIFICORP
Electric Operations
Pro Forma Ave Cost of Long-Term Debt Detail
12 months ended December 31, 2023

						PRINCIPAL AMOUNT				NET PROCEEDS TO COMPANY				
LINE NO.	INTEREST RATE	DESCRIPTION	ISSUANCE DATE	MATURITY DATE	ORIG LIFE	ORIGINAL ISSUE	5QE AVE OUTSTANDING	(DISC)/PREM & ISSUANCE EXPENSES	REDEMPTION EXPENSES	TOTAL DOLLAR AMOUNT	PER $100 PRINCIPAL AMOUNT	MONEY TO COMPANY	ANNUAL DEBT SERVICE COST	LINE NO.
	(a)	(b)	(c)	(d)	(e)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
53	4.297%	Total Long-Term Debt			27		$9,988,550,000	($115,319,627)	($4,247,189)	$9,868,983,183		4.379%	$437,381,884	53
54														54

Docket No. UE 399
Exhibit PAC/202
Witness: Nikki L. Kobliha

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Nikki L. Kobliha

Arizona Public Service Company October 2008 Letter to the Arizona Corporation Commission

March 2022

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CAPITAL CORPORATION

LAW DEPARTMENT

Thomas L. Mumaw
Senior Attorney
(602) 250-2052
Direct Line

October 17, 2008

Arizona Corporation Commission
DOCKETED
OCT 17 2008
DOCKETED BY

Commissioner Kristin K. Mayes
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

Re: Docket No. E-01345A-08-0172 (Interim Rate Motion)

Dear Commissioner Mayes:

On October 8, 2008, you filed a letter in which you requested Arizona Public Service Company ("APS" or "Company") to respond to five specific issues covering a range of subjects. Because several of these issues are germane to the Company's pending Motion for Interim Rates, the Company has chosen to submit its response in the above docket. For the convenience of the parties to this proceeding, I have attached a copy of your October 8th letter as Appendix A.

APS Access to Commercial Paper Market and *Other Credit-Related Issues*

APS first began experiencing trouble accessing the commercial paper market in August of 2007 when the sub-prime credit issues began to impact the capital markets. Access has continued to be sporadic throughout 2008, with the amount of commercial paper APS can issue often being limited even when access to the market was possible. Beginning September 17, 2008, the commercial paper market has been completely closed to APS.

As discussed during the hearing, APS had total lines of credit of $900 million. The first line of $400 million expires at the end of 2010, with a second for $500 million expiring at the end of 2011. The purpose of these lines of credit is to provide the Company with liquidity and working capital when commercial paper cannot be utilized – not fund capital expenditures.[1] Indeed, Decision No. 69947 (October 30, 2007) specifically limited the use of the $500 million line of credit to fuel/purchased power requirements and thus cannot be used to fund the Company's capital requirements. As of September 30, 2008, approximately $270 million had to be drawn down due to the problems in the commercial paper market described above. Also, $34 million of the Company's credit line was with bankrupt Lehman Brothers and thus no longer

[1] Borrowing on bank lines of credit is normally 25 to 50 basis points more expensive than commercial paper.

exists. Another $36 million was with Wachovia, which is in the process of being acquired by Wells Fargo. Whether the new owner of Wachovia will assume the $36 million commitment is uncertain, to say the least. Accordingly, APS's previous $900 million lines of credit are now no more than $866 million, and may be as low as $830 million. Finally, as a result of recent write-downs of bank assets, there is $2 trillion less credit capacity in the U.S. banking system than there was before this global financial crisis began. As a result, APS will likely encounter difficulty in maintaining its remaining lines of credit in the future, and there is no doubt that these lines of credit would, in any case, be insufficient to meet APS's capital expenditure needs over the next few years.

Liquidity is absolutely vital to the financial integrity of an electric utility. APS itself was contacted by each of the three rating agencies after the Lehman Brothers bankruptcy and asked about the Company's exposure to Lehman, Morgan Stanley, Merrill Lynch and Goldman Sachs, as well as its ability to count on its lines of credit given the chaos in the short-term credit markets. A recent example of the critical importance of liquidity is Constellation Energy, the parent of Baltimore Gas & Electric Company, which began 2008 with a stock price of over $100 per share. After facing a liquidity crisis driven by threatened credit rating downgrades and the resultant cash collateral calls that nearly drove Constellation to the brink of bankruptcy, it was forced to sell itself to MidAmerican Energy (the same entity that bought out PacifiCorp) for $26.50 per share.

And the damage has not been limited to the short-term debt market. Despite massive efforts by our Federal government and governments in Europe and Asia to pump liquidity into the national and international credit markets, access to the corporate debt market is extremely strained, with only the most highly-rated corporations being successful in raising long-term debt capital. At present, APS likely could not successfully issue long-term debt. Whether this financial market environment will improve by the spring of next year, when APS likely will need to issue debt, is unknown.

Geo*Smart* Solar Financing Program

On Thursday, September 25, 2008 GE Money announced that it will no longer offer unsecured installment consumer financing for its energy efficiency and renewable energy programs after October 23, 2008 because of the current turmoil in the credit markets. The action specifically affected the Electric & Gas Industries Association's ("EGIA") GEO*Smart* Financing Program offered by APS because GE Money provided the financial support for the program. Although APS had no prior warning of GE Money's actions, APS remains committed to its partnership with EGIA. EGIA, as a non-profit entity implementing similar financing programs for utilities around the country, is situated to identify other suitable financial institutions to back the Geo*Smart* program. In recent conversations, EGIA informed APS that a number of financial institutions have been identified that **may** be able to provide funding for GEO*Smart*. APS remains hopeful but cannot offer any assurance that EGIA will secure other financial backing in the future.

Transactions with Investment Banks or Similar Financial Institutions

Attached as Appendix B is a list of the banks with which APS has existing lines of credit. As noted before, Lehman Brothers and Wachovia are in that group. APS has also submitted a $1.1 million claim against Lehman Brothers in bankruptcy over a hedging transaction. APS has conducted numerous transactions with Morgan Stanley and Goldman Sachs, who together are major players in the U.S energy markets. Although it would seriously reduce the overall liquidity of these energy markets should Morgan Stanley and/or Goldman Sachs bow out of the energy market, APS itself had controls in place well before all these problems began that limited its exposure to any single trading partner, including those discussed above. However, with chaotic and unprecedented market events such as we are presently experiencing, no amount of internal controls can provide complete protection against potential losses.[2] Finally, AIG is a carrier for APS property and casualty insurance. APS believes that these insurance policies will continue to be honored.

Auction Rate Securities

APS does not have any funds invested in auction rate securities ("ARS"). APS is an issuer of ARS, with $343 million outstanding and with maturities in 2029 and 2034. The average rate of interest paid on these securities has been 3.2%, thus providing very attractive financing for APS and its customers.

Palo Verde

Palo Verde Unit 3 experienced two relatively brief unplanned outages recently. The first was from September 16 to September 20 when a failed transmitter in the control circuitry for one of the two power supplies to the reactor control rods required the unit to be shut down. That was safely accomplished, and after the electronic card that included the failed component was replaced, the unit was returned to full power without incident. The second was from September 27 to 30 when high sulfate levels were detected in the secondary steam system (the system that connects the steam generators with the steam turbine). After operators had shut down the unit, the secondary system chemistry was returned to normal, the unit again returned to service without incident and has been operating at full power since then. APS estimates that the amount of additional fuel and purchased power costs deferred for recovery through the PSA to be approximately $3 million.[3]

Neither outage involved what could be characterized as an unusual event for a nuclear power plant and is the sort of occurrence anticipated in the budgeted effective forced outage rate ("EFOR") for Palo Verde. Palo Verde, like all generators, including all APS generators, has an

[2] Although such transactions are not directly with APS, the APS decommissioning trusts and the Pinnacle West retirement funds have relatively small investments in some of the troubled entities identified in your letter, as likely do most if not all large investment funds in this country.

[3] As the Commission is aware, APS absorbs 10% of higher fuel costs, and a portion of outage costs are embedded in the base fuel cost. In addition, a small amount is allocated to wholesale customers. Thus, the total cost of the outages was $4.4 million.

anticipated EFOR based primarily on past operations. This is merely an acknowledgement that all machines, no matter how well designed, constructed, operated, and maintained, will sometimes fail. Electric generators are no exception to that rule.

To date this year, the overall Palo Verde capacity factor has been 98% (excluding refueling outages). This past summer, Palo Verde set an all-time record for generation.

Throughout both outage events, Palo Verde staff demonstrated their safety-first focus by using effective problem identification and resolution behaviors, took proper action during troubleshooting (including developing contingency plans) and work planning. They executed all needed repairs with a focus on human performance. The NRC was kept fully informed throughout these outages and monitored Palo Verde's decision-making process and the actions taken. APS does not believe these outages have had any negative impact on APS's substantial progress in resolving the NRC's Confirmatory Action Letter.

Sincerely,

Thomas L. Mumaw

Thomas L. Mumaw

Attorney for Arizona Public
Service Company

Attachments

cc: Mike Gleason, Chairman
William A. Mundell
Jeff Hatch-Miller
Gary Pierce
Brian McNeil
Ernest Johnson
Lyn A. Farmer
Janet Wagner
Rebecca Wilder
Janice Alward
Parties of Record
Docket Control

Copies of the foregoing emailed or mailed
This 17th day of October 2008 to:

Ernest G. Johnson
Director, Utilities Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, AZ 85007
ejohnson@cc.state.az.us

Maureen Scott
Legal Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, AZ 85007
mscott@azcc.gov

Janet Wagner
Legal Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, AZ 85007
jwagner@azcc.gov

Terri Ford
Utilities Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, AZ 85007
tford@azcc.gov

Barbara Keene
Utilities Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, AZ 85007
bKeene@cc.state.az.us

Daniel Pozefsky
Chief Counsel
RUCO
1110 West Washington, Suite 220
Phoenix, AZ 85007
dpozefsky@azruco.com

William A. Rigsby
RUCO
1110 West Washington, Suite 220
Phoenix, AZ 85007
brigsby@azruco.gov

Tina Gamble
RUCO
1110 West Washington, Suite 220
Phoenix, AZ 85007
egamble@azruco.gov

C. Webb Crockett
Fennemore Craig
3003 North Central, Suite 2600
Phoenix, AZ 85012-2913
wcrocket@fclaw.com

Kevin Higgins
Energy Strategies, LLC
215 South State Street, Suite 200
Salt Lake City, UT 84111
khiggins@energystrat.com

Michael L. Kurtz
Boehm, Kurt & Lowry
36 East Seventh Street, Suite 2110
Cincinnati, OH 45202
mkurtz@BKLlawfirm.com

Kurt J. Boehm
Boehm, Kurt & Lowry
36 East Seventh Street, Suite 2110
Cincinnati, OH 45202
kboehm@BKLlawfirm.com

The Kroger Company
Dennis George
Attn: Corporate Energy Manager (G09)
1014 Vine Street
Cincinnati, OH 45202
dgeorge@kroger.com

Stephen J. Baron
J. Kennedy & Associates
570 Colonial Park Drive
Suite 305
Roswell, GA 30075
sbaron@jkenn.com

Theodore Roberts
Sempra Energy Law Department
101 Ash Street, H Q 13D
San Diego, CA 92101-3017
TRoberts@sempra.com

Lawrence V. Robertson, Jr.
2247 E. Frontage Road
Tubac, AZ 85646
tubaclawyer@aol.com

Michael A. Curtis
501 East Thomas Road
Phoenix, AZ 85012
mcurtis401@aol.com

William P. Sullivan
501 East Thomas Road
Phoenix, AZ 85012
wsullivan@cgsuslaw.com

Larry K. Udall
501 East Thomas Road
Phoenix, AZ 85012
ludall@cgsuslaw.com

Michael Grant
Gallagher & Kennedy, P.A.
2575 East Camelback Road
Phoenix, AZ 85016
MMG@gknet.com

Gary Yaquinto
Arizona Investment Council
2100 North Central, Suite 210
Phoenix, AZ 85004
gyaquinto@arizonaic.org

David Berry
Western Resource Advocates
P.O. Box 1064
Scottsdale, AZ 85252-1064
azbluhill@aol.com

Tim Hogan
Arizona Center for Law in the Public Interest
202 East McDowell Road
Suite 153
Phoenix, AZ 85004
thogan@aclpi.org

Jeff Schlegel
SWEEP Arizona Representative
1167 W. Samalayuca Dr.
Tucson, AZ 85704-3224
schlegelj@aol.com

Jay I. Moyes
MOYES, SELLERS, & SIMS
1850 North Central Avenue, Suite 1100
Phoenix, AZ 85004
jimoyes@lawms.com

Karen Nally
MOYES, SELLERS, & SIMS
1850 North Central Avenue, Suite 1100
Phoenix, AZ 85004
kenally@lawms.com

Jeffrey J. Woner
K.R. Saline & Assoc., PLC
160 N. Pasadena, Suite 101
Mesa, AZ 85201
jjw@krsaline.com

Scott Canty
General Counsel the Hopi Tribe
P.O. Box 123
Kykotsmovi, AZ 86039
Scanty0856@aol.com

Cynthia Zwick
1940 E. Luke Ave
Phoenix, AZ 85016
czwick@azcaa.org

Nicholas J. Enoch
349 North 4th Ave
Phoenix, AZ 85003
nick@lubinandenoch.com

Appendix A

APPENDIX A
Page 1 of 2

ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Commissioner

Direct Line: (602) 542-4143
Fax: (602) 542-0765
E-mail: kmayes@azcc.gov

October 8, 2008

Mr. Don Brandt
President and CEO
Arizona Public Service
400 No. Fifth Street
M.S. 9042
Phoenix, AZ 85004

Re: Impact of recent financial crisis on APS' access to commercial paper markets and ability to finance capital projects; forced cancellation of GeoSmart Solar Loan Program; transactions with investment banks; exposure to auction rate securities; status of outages at Palo Verde Nuclear Generating Station's Unit 3.

Dear Mr. Brandt:

As you know, the recent upheaval in America's financial markets has had an unsettling effect on our national and local economies. It has also had serious consequences for individuals and companies who need to access financing, as credit tightens and capital markets become less fluid.

In recognition of the current environment, I write to request that you provide the Commission with information regarding whether the unfolding events on Wall Street have had an impact on Arizona Public Service Company ("APS"), with a particular focus on several areas.

First, please tell the Commission whether APS has experienced difficulty gaining access to short or long term debt markets. In particular, have you seen a decline in the Company's ability to issue commercial paper, a practice that has become common among large utilities seeking to make payments for short term capital expenditures and operating expenses. If so, please describe the ways in which you have responded to this deficiency in order to meet the Company's capital needs. Have you experienced additional expenses associated with accessing these markets? What is the short-term and long-term impact to APS' planned capital projects?

Second, APS recently reported to my office that it was forced to scuttle its GeoSmart Solar Financing Program – the program by which APS was offering loans to customers wishing to install solar panels who could not afford to do so solely using rebates – because General Electric pulled its funding due to the credit crisis. Please detail the circumstances surrounding this program suspension and whether you believe APS will be able to re-start the program in the future. Please also inform the Commission whether any other renewable energy or other capital expenditure programs have been threatened or come under pressure as a result of the tightened credit markets, and the Company's strategy for addressing these pressures.

Third, please tell the Commission whether APS engaged in any significant financial transactions with Lehman Brothers, American International Group, Bear Stearns, or any other investment firm that has been the subject of recent bankruptcies or governmental takeovers. If so, please detail those transactions, and to what extent they have impacted the Company.

Fourth, it is my understanding that APS has had some exposure to auction rate securities. As you know, the auction rate securities market recently collapsed. Please describe the Company's auction rate securities holdings, what worth those securities now have, and what the Company intends to do with those securities in order to minimize any losses associated with them.

Finally, as you know, Palo Verde Nuclear Generating Station's ("PVNGS") Unit Three was down from September 27th to October 1st – making for a second outage in less than a month. Please tell the Commission how these Unit Three outages will impact the Company's efforts to resolve PVNGS' Category Four status with the Nuclear Regulatory Commission, as well as the estimated replacement costs that have been passed through the Company's Purchased Power and Fuel Adjustment Clause as a result of these outages.

Thank you for your attention to these questions.

Sincerely,

Kris Mayes
Commissioner

Cc: Chairman Mike Gleason
Commissioner William A. Mundell
Commissioner Jeff Hatch-Miller
Commissioner Gary Pierce
Ernest Johnson
Janice Alward
Brian McNeil
Rebecca Wilder

Appendix B

APS Revolving Lines of Credit
($K)

	Bank	Amount	% of Total
1	Bank of America	$92,857	10.3%
2	Bank of New York Mellon	80,000	8.9%
3	Citigroup	76,572	8.5%
4	JPMorgan	76,572	8.5%
5	Keybank	68,571	7.6%
6	CSFB	60,857	6.7%
7	Barclays Bank	52,857	5.9%
8	Wells Fargo	52,857	5.9%
9	UBS Warburg	52,857	5.9%
10	Union Bank	38,571	4.3%
11	Sun Trust	36,000	4.0%
12	Mizuho	28,571	3.2%
13	KBC Bank	24,000	2.7%
14	Dresdner	24,000	2.7%
15	US Bank	17,143	1.9%
16	Chang Hwa Commercial Bk	15,000	1.6%
17	BOTM	11,429	1.3%
18	Northern Trust	11,429	1.3%
19	Bank Hapoalim	10,000	1.1%
20	Subtotal	$830,143	92.3%
21	Wachovia	36,000	4.0%
22	Lehman Brothers	33,857	3.7%
23	Total	$900,000	100.0%

Docket No. UE 399
Exhibit PAC/203
Witness: Nikki L. Kobliha

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Nikki L. Kobliha

New Debt Issue Spreads

March 2022

PACIFICORP
Electric Operations
Pro FormaCost of Long-Term Debt Detail
12 months ended December 31, 2023

LINE NO.	INTEREST RATE	DESCRIPTION	PRINCIPAL AMOUNT ORIGINAL ISSUE	PRINCIPAL AMOUNT 5QE AVE OUTSTANDING	(DISC)/PREM & ISSUANCE EXPENSES	REDEMPTION EXPENSES	NET PROCEEDS TO COMPANY TOTAL DOLLAR AMOUNT	NET PROCEEDS TO COMPANY PER $100 PRINCIPAL AMOUNT	MONEY TO COMPANY	ANNUAL DEBT SERVICE COST	LINE NO.
	(a)	(b)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
53	4.297%	Total Long-Term Debt		$9,988,550,000	($115,319,627)	($4,247,189)	$9,868,983,183		4.379%	$437,381,884	53
	4.146%	Actual Post Acquistion Debt Issuances (1)		$8,903,690,000	($99,919,403)	($777,230)	$8,802,993,368		4.22%	$375,921,750	
	4.674%	Pro Forma Post Acquistion Debt Issuances		$8,903,690,000	($84,671,670)	($777,230)	$8,818,241,100		4.74%	$421,954,214	
	4.767%	Total Long-Term Debt - Pro Forma		$9,988,550,000	($100,071,895)	($4,247,189)	$9,884,230,916		4.840%	$483,414,347	

REDACTED
Docket No. UE 399
Exhibit PAC/204
Witness: Nikki L. Kobliha

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Exhibit Accompanying Direct Testimony of Nikki L. Kobliha

S&P Ratings Direct November 19, 2013

March 2022

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

Docket No. UE 399
Exhibit PAC/205
Witness: Nikki L. Kobliha

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Nikki L. Kobliha

Indicative Forward Pollution Control Revenue Bonds Variable Rates

March 2022

Indicative Forward PCRB Variable Rates
For Quarter End Periods for Year Ending December 31, 2023

	30 Day LIBOR Daily Ave (a)	Floating Rate PCRBs Daily Ave (b)	PCRB / LIBOR (b)/(a)
Jan-00	5.81%	3.33%	57%
Feb-00	5.89%	3.62%	62%
Mar-00	6.05%	3.68%	61%
Apr-00	6.16%	4.02%	65%
May-00	6.54%	4.89%	75%
Jun-00	6.65%	4.35%	65%
Jul-00	6.63%	3.99%	60%
Aug-00	6.62%	4.09%	62%
Sep-00	6.62%	4.50%	68%
Oct-00	6.62%	4.36%	66%
Nov-00	6.63%	4.33%	65%
Dec-00	6.68%	4.14%	62%
Jan-01	5.88%	3.10%	53%
Feb-01	5.53%	3.59%	65%
Mar-01	5.13%	3.18%	62%
Apr-01	4.82%	3.72%	77%
May-01	4.16%	3.38%	81%
Jun-01	3.92%	3.03%	77%
Jul-01	3.82%	2.65%	69%
Aug-01	3.64%	2.36%	65%
Sep-01	3.17%	2.42%	76%
Oct-01	2.48%	2.18%	88%
Nov-01	2.13%	1.79%	84%
Dec-01	1.96%	1.64%	84%
Jan-02	1.81%	1.49%	82%
Feb-02	1.85%	1.39%	75%
Mar-02	1.89%	1.46%	77%
Apr-02	1.86%	1.58%	85%
May-02	1.84%	1.67%	91%
Jun-02	1.84%	1.58%	86%
Jul-02	1.83%	1.49%	81%
Aug-02	1.80%	1.49%	83%
Sep-02	1.82%	1.69%	93%
Oct-02	1.81%	1.84%	102%
Nov-02	1.44%	1.66%	115%
Dec-02	1.42%	1.57%	110%
Jan-03	1.36%	1.40%	103%
Feb-03	1.34%	1.43%	107%
Mar-03	1.31%	1.45%	111%
Apr-03	1.31%	1.52%	115%
May-03	1.31%	1.56%	119%
Jun-03	1.16%	1.38%	119%
Jul-03	1.11%	1.12%	102%
Aug-03	1.11%	1.16%	104%
Sep-03	1.12%	1.24%	111%
Oct-03	1.12%	1.24%	111%
Nov-03	1.13%	1.36%	121%
Dec-03	1.15%	1.32%	114%
Jan-04	1.11%	1.21%	110%
Feb-04	1.10%	1.17%	107%
Mar-04	1.09%	1.20%	110%
Apr-04	1.10%	1.27%	115%
May-04	1.10%	1.29%	117%
Jun-04	1.25%	1.28%	102%
Jul-04	1.41%	1.26%	89%
Aug-04	1.60%	1.40%	88%
Sep-04	1.78%	1.49%	83%
Oct-04	1.90%	1.72%	91%
Nov-04	2.19%	1.65%	75%
Dec-04	2.39%	1.67%	70%
Jan-05	2.49%	1.78%	72%
Feb-05	2.61%	1.88%	72%
Mar-05	2.81%	1.95%	69%
Apr-05	2.97%	2.50%	84%
May-05	3.09%	2.93%	95%
Jun-05	3.25%	2.39%	74%
Jul-05	3.43%	2.28%	67%
Aug-05	3.69%	2.44%	66%
Sep-05	3.78%	2.55%	68%
Oct-05	3.99%	2.66%	67%
Nov-05	4.15%	2.93%	71%
Dec-05	4.36%	3.10%	71%
Jan-06	4.48%	3.02%	67%
Feb-06	4.58%	3.13%	68%

Indicative Forward PCRB Variable Rates
For Quarter End Periods for Year Ending December 31, 2023

	30 Day LIBOR Daily Ave (a)	Floating Rate PCRBs Daily Ave (b)	PCRB / LIBOR (b)/(a)
Mar-06	4.76%	3.11%	65%
Apr-06	4.92%	3.45%	70%
May-06	5.08%	3.52%	69%
Jun-06	5.24%	3.74%	71%
Jul-06	5.37%	3.60%	67%
Aug-06	5.35%	3.53%	66%
Sep-06	5.33%	3.61%	68%
Oct-06	5.32%	3.57%	67%
Nov-06	5.32%	3.62%	68%
Dec-06	5.35%	3.70%	69%
Jan-07	5.32%	3.64%	68%
Feb-07	5.32%	3.63%	68%
Mar-07	5.32%	3.64%	68%
Apr-07	5.32%	3.79%	71%
May-07	5.32%	3.90%	73%
Jun-07	5.32%	3.76%	71%
Jul-07	5.32%	3.66%	69%
Aug-07	5.52%	3.76%	68%
Sep-07	5.48%	3.84%	70%
Oct-07	4.98%	3.56%	72%
Nov-07	4.75%	3.53%	74%
Dec-07	5.00%	3.25%	65%
Jan-08	3.95%	3.02%	76%
Feb-08	3.14%	2.86%	91%
Mar-08	2.80%	3.79%	135%
Apr-08	2.79%	2.23%	80%
May-08	2.63%	1.93%	73%
Jun-08	2.47%	2.77%	112%
Jul-08	2.46%	4.12%	168%
Aug-08	2.47%	3.03%	123%
Sep-08	2.94%	4.57%	155%
Oct-08	3.87%	4.89%	126%
Nov-08	1.68%	2.34%	139%
Dec-08	1.01%	1.02%	101%
Jan-09	0.39%	0.70%	181%
Feb-09	0.46%	0.68%	147%
Mar-09	0.53%	0.66%	124%
Apr-09	0.45%	0.63%	140%
May-09	0.35%	0.53%	153%
Jun-09	0.32%	0.45%	143%
Jul-09	0.29%	0.41%	142%
Aug-09	0.27%	0.43%	158%
Sep-09	0.25%	0.40%	161%
Oct-09	0.24%	0.39%	159%
Nov-09	0.24%	0.37%	157%
Dec-09	0.23%	0.38%	165%
Jan-10	0.23%	0.32%	138%
Feb-10	0.23%	0.32%	137%
Mar-10	0.24%	0.32%	135%
Apr-10	0.26%	0.35%	134%
May-10	0.33%	0.34%	101%
Jun-10	0.35%	0.33%	93%
Jul-10	0.33%	0.30%	90%
Aug-10	0.27%	0.31%	115%
Sep-10	0.26%	0.31%	119%
Oct-10	0.26%	0.27%	106%
Nov-10	0.25%	0.27%	107%
Dec-10	0.26%	0.29%	110%
Jan-11	0.26%	0.26%	100%
Feb-11	0.26%	0.26%	98%
Mar-11	0.25%	0.24%	96%
Apr-11	0.22%	0.24%	106%
May-11	0.20%	0.20%	100%
Jun-11	0.19%	0.12%	62%
Jul-11	0.19%	0.07%	38%
Aug-11	0.21%	0.18%	83%
Sep-11	0.23%	0.18%	78%
Oct-11	0.24%	0.17%	69%
Nov-11	0.25%	0.18%	70%
Dec-11	0.28%	0.18%	62%
Jan-12	0.28%	0.18%	64%
Feb-12	0.25%	0.22%	86%
Mar-12	0.24%	0.20%	84%
Apr-12	0.24%	0.25%	104%

Indicative Forward PCRB Variable Rates
For Quarter End Periods for Year Ending December 31, 2023

	30 Day LIBOR Daily Ave	Floating Rate PCRBs Daily Ave	PCRB / LIBOR
	(a)	(b)	(b)/(a)
May-12	0.24%	0.22%	90%
Jun-12	0.24%	0.19%	78%
Jul-12	0.25%	0.17%	68%
Aug-12	0.24%	0.16%	68%
Sep-12	0.22%	0.18%	81%
Oct-12	0.21%	0.20%	93%
Nov-12	0.21%	0.20%	95%
Dec-12	0.21%	0.15%	71%
Jan-13	0.21%	0.10%	51%
Feb-13	0.20%	0.13%	63%
Mar-13	0.20%	0.13%	66%
Apr-13	0.20%	0.18%	92%
May-13	0.20%	0.18%	90%
Jun-13	0.19%	0.11%	57%
Jul-13	0.19%	0.08%	43%
Aug-13	0.18%	0.09%	47%
Sep-13	0.18%	0.09%	49%
Oct-13	0.17%	0.10%	61%
Nov-13	0.17%	0.13%	78%
Dec-13	0.17%	0.14%	82%
Jan-14	0.16%	0.12%	74%
Feb-14	0.16%	0.11%	74%
Mar-14	0.15%	0.11%	73%
Apr-14	0.15%	0.13%	87%
May-14	0.15%	0.12%	80%
Jun-14	0.15%	0.10%	67%
Jul-14	0.15%	0.09%	61%
Aug-14	0.16%	0.09%	61%
Sep-14	0.15%	0.09%	55%
Oct-14	0.15%	0.08%	55%
Nov-14	0.15%	0.09%	59%
Dec-14	0.16%	0.08%	50%
Jan-15	0.17%	0.06%	38%
Feb-15	0.17%	0.06%	36%
Mar-15	0.18%	0.06%	35%
Apr-15	0.18%	0.09%	50%
May-15	0.18%	0.15%	79%
Jun-15	0.19%	0.13%	69%
Jul-15	0.19%	0.10%	55%
Aug-15	0.20%	0.09%	46%
Sep-15	0.20%	0.09%	47%
Oct-15	0.19%	0.10%	50%
Nov-15	0.21%	0.09%	45%
Dec-15	0.35%	0.08%	24%
Jan-16	0.43%	0.09%	20%
Feb-16	0.43%	0.08%	20%
Mar-16	0.44%	0.19%	45%
Apr-16	0.44%	0.41%	94%
May-16	0.44%	0.41%	93%
Jun-16	0.45%	0.43%	95%
Jul-16	0.48%	0.43%	89%
Aug-16	0.51%	0.49%	96%
Sep-16	0.53%	0.71%	134%
Oct-16	0.53%	0.77%	146%
Nov-16	0.56%	0.58%	103%
Dec-16	0.71%	0.66%	93%
Jan-17	0.77%	0.69%	89%
Feb-17	0.78%	0.66%	84%
Mar-17	0.93%	0.71%	77%
Apr-17	0.99%	0.90%	91%
May-17	1.01%	0.82%	81%
Jun-17	1.17%	0.83%	71%
Jul-17	1.23%	0.85%	69%
Aug-17	1.23%	0.79%	65%
Sep-17	1.23%	0.87%	71%
Oct-17	1.24%	0.93%	75%
Nov-17	1.29%	0.96%	75%
Dec-17	1.49%	1.25%	84%
Jan-18	1.56%	1.35%	86%
Feb-18	1.60%	1.10%	69%
Mar-18	1.80%	1.32%	73%
Apr-18	1.90%	1.75%	92%
May-18	1.95%	1.46%	75%
Jun-18	2.07%	1.33%	64%

Indicative Forward PCRB Variable Rates
For Quarter End Periods for Year Ending December 31, 2023

	30 Day LIBOR Daily Ave (a)	Floating Rate PCRBs Daily Ave (b)	PCRB / LIBOR (b)/(a)
Jul-18	2.08%	1.10%	53%
Aug-18	2.07%	1.53%	74%
Sep-18	2.18%	1.56%	72%
Oct-18	2.29%	1.60%	70%
Nov-18	2.32%	1.69%	73%
Dec-18	2.45%	1.70%	69%
Jan-19	2.51%	1.43%	57%
Feb-19	2.49%	1.64%	66%
Mar-19	2.49%	1.67%	67%
Apr-19	2.48%	1.90%	77%
May-19	2.44%	1.72%	70%
Jun-19	2.40%	1.79%	74%
Jul-19	2.31%	1.45%	63%
Aug-19	2.17%	1.45%	67%
Sep-19	2.04%	1.48%	72%
Oct-19	1.88%	1.41%	75%
Nov-19	1.74%	1.18%	68%
Dec-19	1.75%	1.34%	77%
Jan-20	1.67%	1.10%	66%
Feb-20	1.64%	1.21%	74%
Mar-20	0.92%	2.68%	292%
Apr-20	0.68%	0.85%	124%
May-20	0.19%	0.27%	139%
Jun-20	0.18%	0.19%	102%
Jul-20	0.17%	0.21%	125%
Aug-20	0.16%	0.17%	106%
Sep-20	0.15%	0.16%	108%
Oct-20	0.15%	0.17%	116%
Nov-20	0.14%	0.17%	121%
Dec-20	0.15%	0.15%	100%
Jan-21	0.13%	0.11%	85%
Feb-21	0.11%	0.06%	56%
Mar-21	0.11%	0.07%	70%
Apr-21	0.11%	0.10%	91%
May-21	0.10%	0.11%	113%
Jun-21	0.09%	0.07%	76%
Jul-21	0.09%	0.05%	54%
Aug-21	0.09%	0.04%	46%
Sep-21	0.08%	0.04%	50%
Oct-21	0.09%	0.08%	92%
Nov-21	0.09%	0.08%	89%
Dec-21	0.10%	0.11%	106%
Average			85%

	Forward 1 Mo BSBY Index* (1)	Historical Floating Rate PCRB / 30 Day LIBOR (2)	Forecast Floating Rate PCRB (1) * (2)
12/31/2022	0.94%	85%	0.801%
3/31/2023	1.16%	85%	0.985%
6/30/2023	1.36%	85%	1.153%
9/30/2023	1.56%	85%	1.323%
12/31/2023	1.57%	85%	1.338%
5QE Ave			1.120%

* Source: Bloomberg L.P. (1/4/22)

Docket No. UE 399
Exhibit PAC/206
Witness: Nikki L. Kobliha

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Nikki L. Kobliha

Cost of Preferred Stock

March 2022

PACIFICORP
Electric Operations
Cost of Preferred Stock
12 Months Ended December 31, 2023

Line No.	Description of Issue	Issuance Date	Call Price	Annual Dividend Rate	Shares O/S	Total Par or Stated Value O/S	Net Premium & (Expense)	Net Proceeds to Company	% of Gross Proceeds	Cost of Money	Annual Cost	Line No.
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	
1	**Serial Preferred, $100 Par Value**											1
2	7.00% Series	(a)	None	7.000%	18,046	$1,804,600	(b)	$1,804,600	100.000%	7.000%	$126,322	2
3	6.00% Series	(a)	None	6.000%	5,930	$593,000	(b)	$593,000	100.000%	6.000%	$35,580	3
4												4
5	**Total Cost of Preferred Stock**			**6.753%**	**23,976**	**$2,397,600**	**$0**	**$2,397,600**		**6.753%**	**$161,902**	5
6												6
7												7
8	(a) These issues replaced an issue of The California Oregon Power Company as a result of the merger of that Company into Pacific Power & Light Co.											8
9	(b) Original issue expense/premium has been fully amortized or expensed.											9
10												10

Docket No. UE 399
Exhibit PAC/300
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Ann E. Bulkley

March 2022

TABLE OF CONTENTS

ATTACHED EXHIBITS

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Ann E. Bulkley. I am a Principal at The Brattle Group (Brattle). My business address is One Beacon Street, Suite 2600, Boston, Massachusetts 02108.

Q. What is your position with The Brattle Group?

A. I am employed by Brattle as a Principal.

Q. On whose behalf are you submitting this direct testimony?

A. I am submitting this direct testimony before the Public Utility Commission of Oregon (Commission) on behalf of PacifiCorp d/b/a/ Pacific Power (PacifiCorp or the Company), which is an indirect wholly owned subsidiary of Berkshire Hathaway Energy Company (BHE).

Q. Please describe your background and professional experience in the energy and utility industries.

A. I hold a Bachelor's degree in Economics and Finance from Simmons College and a Master's degree in Economics from Boston University, with over 25 years of experience consulting to the energy industry. I have advised numerous energy and utility clients on a wide range of financial and economic issues with primary concentrations in valuation and utility rate matters. Many of these assignments have included the determination of the cost of capital for valuation and ratemaking purposes. My resume and a summary of testimony that I have filed in other proceedings are included as Exhibit PAC/301 to this testimony.

Q. Have you previously testified before the Commission or other regulatory authorities?

A. Yes. A list of proceedings in which I have provided testimony is provided in Exhibit PAC/301 to this testimony.

II. PURPOSE AND OVERVIEW OF TESTIMONY

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to present evidence and provide a recommendation regarding the appropriate Return on Equity (ROE)[1] for PacifiCorp's electric utility operations in Oregon and to provide an assessment of its proposed capital structure to be used for ratemaking purposes. A summary of my ROE analyses and results is provided in Exhibit PAC/302. My analysis and recommendations are supported by the data presented in Exhibit PAC/303 through Exhibit PAC/311, which were prepared by me or under my direction.

Q. Please provide a brief overview of the analyses that led to your ROE recommendation.

A. As discussed in more detail in Section VII, I applied the Constant Growth, Multi-Stage, and Projected forms of the Discounted Cash Flow (DCF) model, the Capital Asset Pricing Model (CAPM), and the Bond Yield Plus Risk Premium approach. My recommendation also takes into consideration: (1) PacifiCorp's capital expenditure requirements; (2) the regulatory environment in which PacifiCorp operates; (3) PacifiCorp's adjustment mechanisms; and (4) the fuel sources of PacifiCorp's generation portfolio.

[1] Throughout my direct testimony, I interchangeably use the terms "ROE" and "cost of equity".

Finally, I considered PacifiCorp's proposed capital structure as compared to the capital structures of the proxy companies.[2] While I did not make any specific adjustments to my ROE estimates for any of these factors, I did take them into consideration in aggregate when determining where PacifiCorp's ROE falls within the range of analytical results.

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

A. Section III provides a summary of my analyses and conclusions. Section IV reviews the regulatory guidelines pertinent to the development of the cost of capital. Section V discusses current and prospective capital market conditions and the effect of those conditions on PacifiCorp's cost of equity. Section VI explains my selection of a proxy group of electric utilities. Section VII describes my analyses and the analytical basis for the recommendation of the appropriate ROE for PacifiCorp. Section VIII provides a discussion of specific business and financial risks that have a direct bearing on the ROE to be authorized for PacifiCorp in this case. Section IX discusses PacifiCorp's capital structure as compared with the capital structures of the utility operating company subsidiaries of the proxy group companies. Section X presents my conclusions and recommendations.

III. SUMMARY OF ANALYSES AND CONCLUSIONS

Q. What is your recommended ROE for PacifiCorp?

A. Based on the analytical results in Figure 1 below, I believe a range from 9.90 percent to 10.75 percent is reasonable. The Company is requesting a return of 9.80 percent.

[2] The selection and purpose of developing a group of comparable companies is discussed in detail in Section VI of my direct testimony.

This request considers the range of results for the proxy group companies, the relative business, financial, and regulatory risks of PacifiCorp's electric operations in Oregon as compared to the proxy group, and current capital market conditions and balances the interests of customers and shareholders.

Q. Please summarize the key factors considered in your analyses and upon which you base your recommended ROE.

A. My analyses and recommendations considered the following:

- The United States (U.S.) Supreme Court's *Hope* and *Bluefield* decisions,[3] which established the standards for determining a fair and reasonable authorized ROE, including consistency of the authorized return with other businesses having similar risk, adequacy of the return to ensure access to capital and support credit quality, and the necessity for the end result to lead to just and reasonable rates.
- The required ROE should be a forward-looking estimate; therefore, the analyses supporting my recommendation rely on forward-looking inputs and assumptions (*e.g.*, forecasted growth rates in the DCF model, projected interest rates and a forward-looking market risk premium in the CAPM.).
- The effect of current and prospective capital market conditions on the ROE estimation models and on investors' return requirements.
- PacifiCorp's business risks relative to the proxy group companies and the implications of those risks in arriving at the appropriate ROE.

[3] *Bluefield Waterworks & Improvement Co. v. Pub. Serv. Comm'n of W. Va.*, 262 U.S. 679, 692-93 (1923); *Fed. Power Comm'n v. Hope Natural Gas Co*., 320 U.S. 591, 603 (1944).

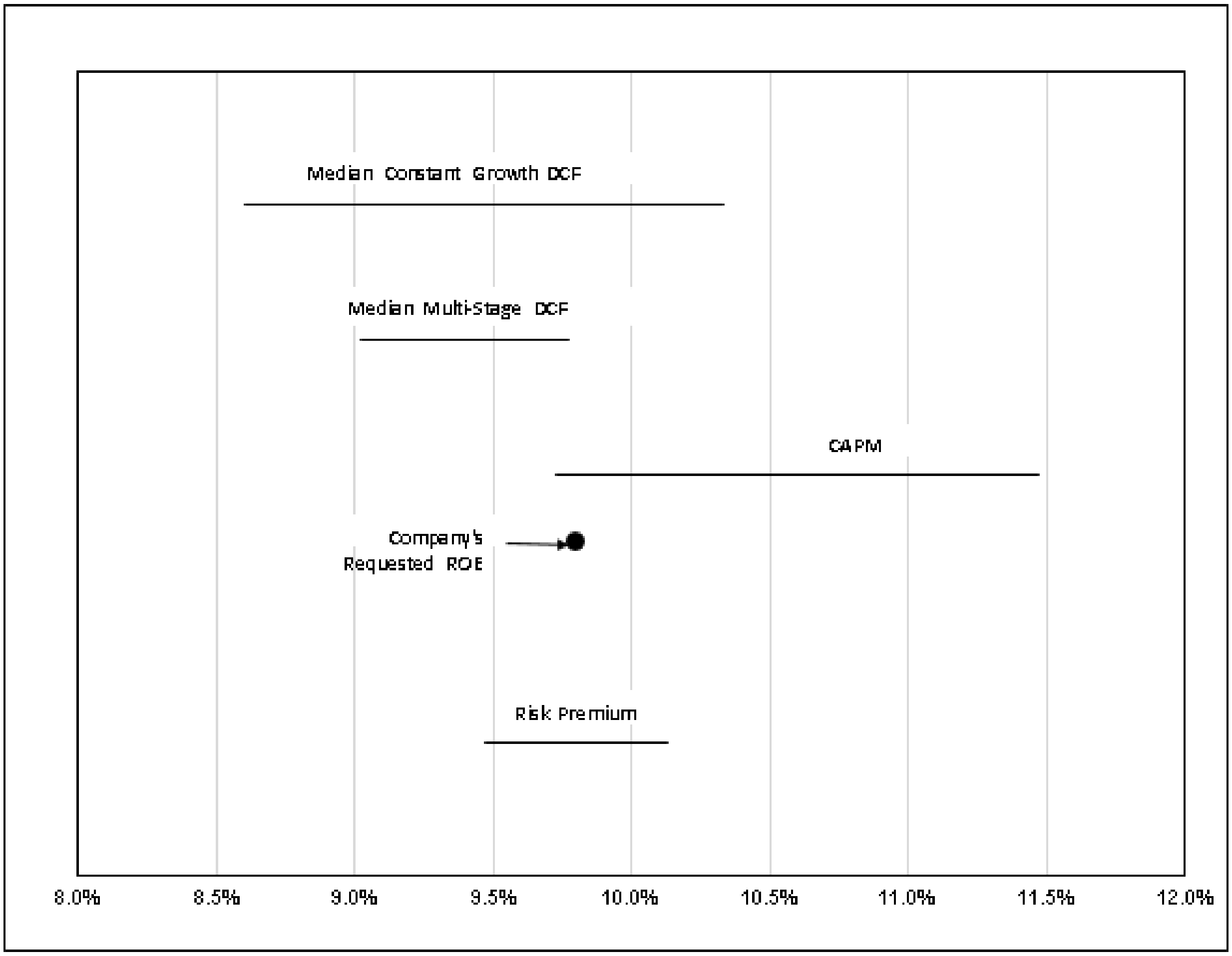
Q. Please explain how you considered those factors.

A. I relied on the results of several analytical approaches to estimate PacifiCorp's cost of equity based on a proxy group of publicly-traded companies. As shown in Figure 1, those ROE estimation models produce a wide range of results. My conclusion about where within that range of results PacifiCorp's ROE should be placed is based on PacifiCorp's business and financial risk relative to the proxy group. Although the companies in my proxy group are generally comparable to PacifiCorp, each company is unique and no two companies have the exact same business and financial risk profiles. Accordingly, I selected a proxy group with similar, but not identical risk profiles, and I adjusted the results of my analysis either upward or downward within the reasonable range of results to account for any residual differences in risk.

Q. Please summarize the ROE estimation models that you considered to establish the range of ROEs for PacifiCorp's Oregon operations.

A. I considered the results of two forms of the DCF model; the Constant Growth DCF, and the Multi-Stage DCF. In addition, I considered the results of the CAPM, and Risk Premium. The results of these analyses are summarized in Figure 1 below.

Figure 1: Summary of Analytical Results



As shown in Figure 1, the range of results produced by the Constant Growth DCF estimation model is relatively wide, particularly in relation to the results of the other methodologies. While it is common to consider multiple models to estimate the cost of equity, it is particularly important when the range of results varies considerably across methodologies.

Furthermore, as shown in Exhibit PAC/304, the median results of both the Constant Growth and Multi-Stage DCF analyses using the earnings lowest growth rates for each of the proxy group companies produce results that are below recently authorized ROEs for electric utilities in the U.S. that are relying on traditional original cost ratemaking. Therefore, I conclude that these results do not provide a sufficient risk premium to compensate equity investors for the residual risks of ownership, including the risk that they have the lowest claim on the assets and income of PacifiCorp.

Although I have concerns about the results produced by the DCF models, my ROE recommendation considers the range between the median and median-high results of the DCF models. In addition, I consider the results of forward-looking CAPM and a Bond Yield Plus Risk Premium analysis. I also consider company-specific risk factors, and current and prospective capital market conditions.

As I will discuss, expected changes in capital market conditions will affect the results of the ROE estimation models, making it important to review results based on historical or current data recognizing that these conditions may not represent the forward-looking cost of equity. The assumptions in each of the models are affected differently. In determining the appropriate forward-looking ROE, it is important to recognize these limitations in the static models and consider how the results may differ during the period over which the rates in this proceeding will be in effect. For example, dividend yields in the DCF model are affected by the recent historical high stock prices. As accommodative monetary policies begin to be reversed, it is reasonable to expect that utility stocks will underperform the broader market. Lower stock prices increasing dividend yields on utility stocks and all else equal, would increase the ROE resulting from the DCF model. Further, the Federal Reserve has signaled its intention to increase interest rates. Increases in interest rates are likely to affect the bond yields used in the CAPM. Therefore, it would be reasonable to consider scenarios of this model that reflect changes in bond yields.

Q. Please summarize the analysis you conducted in determining that PacifiCorp's requested capital structure is reasonable and appropriate.

A. Based on the analysis presented in Section IX of my direct testimony, I conclude that PacifiCorp's proposed common equity ratio of 52.25 percent is reasonable. To make this determination, I reviewed the capital structures of the utility operating subsidiaries of the proxy companies. As shown in Exhibit PAC/311, the results of that analysis demonstrate that the equity ratios for the utility operating companies held by the proxy group range from 46.85 percent to 61.11 percent with a median of 52.71 percent. PacifiCorp's proposed common equity ratio of 52.25 percent is well within the range established for the utility operating subsidiaries of the proxy group companies and is reasonable.

Furthermore, a fundamental aspect of the financial regulation of utilities is assuring that the subject utility has a reasonable opportunity to earn a return on capital consistent with the return available on investments of similar risk. While this principle is most often discussed in terms of the allowed ROE, it is equally applicable to all aspects of the overall Rate of Return (ROR). The equity return, which is the product of the ROE and the equity ratio, (*i.e.*, the Weighted Return on Equity (WROE)), ultimately defines the return to shareholders, and the product of the cost of debt and the debt ratio ensures that a company's debt obligations are met. Therefore, it is necessary to consider both the rates that are applied to debt and equity and the composition of the capital structure to determine the reasonableness of the

ROR. Taken together, PacifiCorp's proposed common equity ratio of 52.25 percent and its requested ROE of 9.80 percent, result in a WROE of 5.12 percent. This return reasonably balances the interests of customers and shareholders by enabling PacifiCorp to maintain its financial integrity and therefore its ability to attract capital at reasonable terms and conditions under a variety of economic and financial market conditions.

IV. REGULATORY GUIDELINES

Q. Please describe the principles that guide the establishment of the cost of capital for a regulated utility.

A. The U.S. Supreme Court's precedent-setting *Hope* and *Bluefield* cases established the standards for determining the fairness or reasonableness of a utility's authorized ROE. Among the standards established by the Court in those cases are: (1) consistency with other businesses having similar or comparable risks; (2) adequacy of the return to support credit quality and access to capital; and (3) the principle that the specific means of arriving at a fair return are not important, only that the end result leads to just and reasonable rates.[4]

Q. Has the Commission provided similar guidance in establishing the appropriate return on common equity?

A. Yes. The Commission follows the precedents of the *Hope* and *Bluefield* cases by acknowledging that utility investors are entitled to a fair and reasonable return. For example, in the Company's last rate determination the Commission stated:

> In establishing fair and reasonable rates under ORS 756.040, we balance the interests of the utility investor and customers by

[4] *Bluefield*, 262 U.S. at 692-93; *Hope*, 320 U.S. at 603.

> ensuring that the rates provide adequate revenue both for operating expenses and for capital costs of the utility, with a return to the equity holder that is "commensurate with the return on investments in other enterprises having corresponding risks" and "sufficient to ensure confidence in the financial integrity of the utility, allowing the utility to maintain its credit and attract capital."[5]

This guidance is in accordance with the *Hope* and *Bluefield* decisions and the principles that I employed to estimate the ROE for PacifiCorp, including the principle that an allowed ROR must be sufficient to enable regulated companies like PacifiCorp to attract capital on reasonable terms.

Q. Why is it important for a utility to be allowed the opportunity to earn a return that is adequate to attract capital at reasonable terms?

A. An ROE that is adequate to attract capital at reasonable terms enables a utility to continue to provide safe, reliable service while maintaining its financial integrity. To the extent that the utility is provided the opportunity to earn its market-based cost of capital, neither customers nor shareholders are disadvantaged.

Q. What are your conclusions regarding regulatory guidelines?

A. The ratemaking process is premised on the principle that, in order for investors and companies to commit the capital needed to provide safe and reliable utility services, a utility must have the opportunity to recover the return of, and the market-required return on, its invested capital. Because utility operations are capital-intensive, regulatory decisions should enable the utility to attract capital at reasonable terms; doing so balances the long-term interests of the utility and its customers.

The financial community carefully monitors the current and expected

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[5] *In the Matter of PacifiCorp, dba Pacific Power, request for a General Rate Revision*, Docket No. UE 374, Order No. 20-473 at 6 (Dec. 18, 2020).

financial condition of utility companies and the regulatory framework in which they operate. In that respect, the regulatory framework is one of the most important factors in both debt and equity investors' assessments of risk. The Commission's order in this proceeding, therefore, should establish rates that provide PacifiCorp with the opportunity to earn an ROE that is: (1) adequate to attract capital at reasonable terms; (2) sufficient to ensure its financial integrity; and (3) commensurate with returns on investments in enterprises with similar risk. To the extent that PacifiCorp is authorized the opportunity to earn its market-based cost of capital, the proper balance is achieved between customers' and shareholders' interests.

V. CAPITAL MARKET CONDITIONS

Q. Why is it important to analyze capital market conditions?

A. The ROE estimation models rely on market data that are either specific to the proxy group, in the case of the DCF model, or to the expectations of market risk, in the case of the CAPM. The results of the ROE estimation models can be affected by prevailing market conditions at the time the analysis is performed. While the ROE that is established in a rate proceeding is intended to be forward-looking, the analyst uses current and projected market data, specifically stock prices, dividends, growth rates and interest rates, in the ROE estimation models to estimate the required return for the subject company.

As discussed in the remainder of this section, analysts and regulatory commissions have concluded that current market conditions have affected the results of the ROE estimation models. As a result, it is important to consider the effect of these conditions on the ROE estimation models when determining the appropriate range and recommended ROE for a future period. If investors do not expect current market conditions to be sustained in the future, it is possible that the ROE estimation models will not provide an accurate estimate of investors' required return during that rate period. Therefore, it is very important to consider projected market data to estimate the return for that forward-looking period.

Q. What factors are affecting the cost of equity for regulated utilities in the current and prospective capital markets?

A. The cost of equity for regulated utility companies is being affected by several factors in the current and prospective capital markets, including: (1) the dramatic shifts in market conditions during 2020, (2) the economic recovery in 2021 and the currently high inflation and the expectations for rising interest rates and continued inflation in 2022, and (3) the effect of these changes on the assumptions used in the ROE estimation models. In this section, I discuss each of these factors and how it affects the models used to estimate the cost of equity for regulated utilities.

Q. What effect do current and prospective market conditions have on the cost of equity for PacifiCorp?

A. The economy is currently in the recovery phase of the business cycle. During the recovery phase, interest rates and inflation are expected to increase. In fact, inflation is currently at its highest level seen in approximately 40 years while interest rates have increased from the pandemic lows seen in 2020. Utilities, which are a defensive sector, have historically underperformed the market during periods of economic expansion. Therefore, investors are currently expecting utilities to underperform over the near-term, which means the share prices of utilities will likely decline. A decline in share prices will increase the dividend yields of utilities and thus the cost of equity for utilities is expected to increase over the near-term. This is important because the cost of equity in this proceeding is being estimated for the period that PacifiCorp's rates will be in effect. Since the cost of equity is expected to increase over the near-term for utilities, ROE estimates based on current market conditions will understate the ROE during the period that the Company's rates will be in effect. For example, the DCF model, which relies on historical averages of share prices, is likely to understate the cost of equity for PacifiCorp over the near term.

Q. Do recent economic projections indicate the expectation for a continued strong economic recovery in 2022?

A. Yes. Economic data beginning in mid-2021 had been indicating the expectation for strong economic recovery and inflationary pressure in response to that recovery. The Federal Open Market Committee (FOMC), which is composed of 12 members including the Board of Governors of the Federal Reserve system and presidents of the Federal Reserve Banks, reviews economic and financial conditions, determines the appropriate stance for monetary policy and assesses the risks to its long-run goals of price stability and economic growth. The FOMC issued its Summary of Economic Projections in December 2021, where the FOMC's median projection for Gross Domestic Product (GDP) growth from Q4 2021 to Q4 2022 is 4.0 percent.[6] Several months prior to the FOMC guidance, issued in December 2021, the Congressional Budget Office (CBO) issued an update to its outlook on economic conditions on July 1, 2021. In that report, the CBO projected strong GDP growth for 2021 and

[6] Federal Open Market Committee, Summary of Economic Projections at 2 (Dec. 15, 2021).

beyond, and significant strength in overall economic conditions including:

- Real GDP growth of 7.4 percent in 2021 and 3.1 percent in 2022, which is a significant change from the negative 2.4 percent growth rate in 2020;
- Inflation indicators at or above the 2.0 percent threshold in 2021 and continuing through 2031;
- Labor force expected to be restored to pre-pandemic levels in 2022; and
- Interest rates on federal borrowing increasing through 2031.[7]

These trends indicate strong economic recovery over the next year, with robust consumer spending expected.

Q. Please summarize the monetary policy actions of the Federal Reserve in response to the COVID-19 pandemic.

A. In response to the COVID-19 pandemic, the Federal Reserve:

- decreased the Federal Funds rate twice in March 2020, resulting in a target range of 0.00 percent to 0.25 percent.
- increased its holdings of both Treasury and mortgaged-back securities.
- started expansive programs to support credit to large employers—the Primary Market Corporate Credit Facility to provide liquidity for new issuances of corporate bonds; and the Secondary Market Corporate Credit Facility to provide liquidity for outstanding corporate debt issuances; and
- supported the flow of credit to consumers and businesses through the Term Asset-Backed Securities Loan Facility.

[7] Congressional Budget Office, An Update to the Budget and Economic Outlook 2021 to 2031, July 2021.

In addition, Congress passed the Coronavirus Aid, Relief, and Economic Security Act in March 2020, the Consolidated Appropriations Act in December 2020 and the American Rescue Plan Act in March 2021, which included $2.2. trillion, $900 billion and $1.9 trillion, respectively, in fiscal stimulus aimed at also mitigating the economic effects of COVID-19. These expansive monetary and fiscal programs mitigated the economic effects of the COVID-19 pandemic and are currently providing additional support as the economy recovers from the COVID-19 recession.

Q. Are there indications that the Federal Reserve is normalizing monetary policy?

A. Yes. At its December 15, 2021 meeting, the Federal Reserve decided to increase the pace of its taper of bond purchases in response to inflation exceeding its target of 2 percent for a sustained period of time. Beginning in January 2022, the Federal Reserve will reduce asset purchases of Treasuries by $20 billion and mortgage-backed securities by $10 billion on a monthly basis.[8] This change is double the initial plan outlined at the Federal Reserve's November 2, 2021 meeting which called for reducing asset purchases of Treasuries by $10 billion and mortgage-backed securities by $5 billion on a monthly basis.[9] At that time, the Federal Reserve's FOMC was forecasting three increases in the federal funds rate by the end of 2022,[10] which was a substantial increase from the one increase that was forecasted by the FOMC at the September 22, 2021 meeting.[11]

Q. Why has the Federal Reserve decided to normalize monetary policy?

A. The Federal Reserve has accelerated plans to normalize monetary policy in response

[8] Press Release, Federal Reserve (Dec. 15, 2021).
[9] Press Release, Federal Reserve (Nov. 3, 2021).
[10] Summary of Economic Projections, Federal Reserve (Dec. 15, 2021).
[11] Summary of Economic Projections, Federal Reserve (Sept. 22, 2021).

to increasing inflation. While the Federal Reserve initially viewed inflation as transitory, it has been higher and more persistent than the target levels and is expected to continue in 2022. Specifically, Federal Reserve Chairman Jerome Powell stated:

> We are phasing out our purchases more rapidly because with elevated inflation pressures and a rapidly strengthening labor market the economy no longer needs increasing amounts of policy support.[12]

Since December 2021, the Federal Reserve has indicated in a number of statements that it intends to respond to rising inflation with increases in interest rates. Most recently, on January 11, 2022, in a hearing before the Senate Banking Committee, Federal Reserve Chairman Powell stated that he expects inflation to persist into mid-2022. Further, Chairman Powell noted that if inflation persists at high levels, the Federal Reserve will be prepared to respond by raising interest rates and beginning to taper bond purchases "sooner and faster" than in prior circumstances where there was a need to taper. In addition, he noted that the economy no longer required aggressive stimulus and that the Federal Reserve would start to revert to the interest rates maintained before the pandemic.[13]

In fact, Goldman Sachs recently noted that it expects the Federal Reserve to increase the federal funds rate four times in 2022 in response to rising inflation as opposed to the December 2021 projection of three increases by the Federal Reserve.[14] Further, the former New York Federal Reserve President, William Dudley, suggested

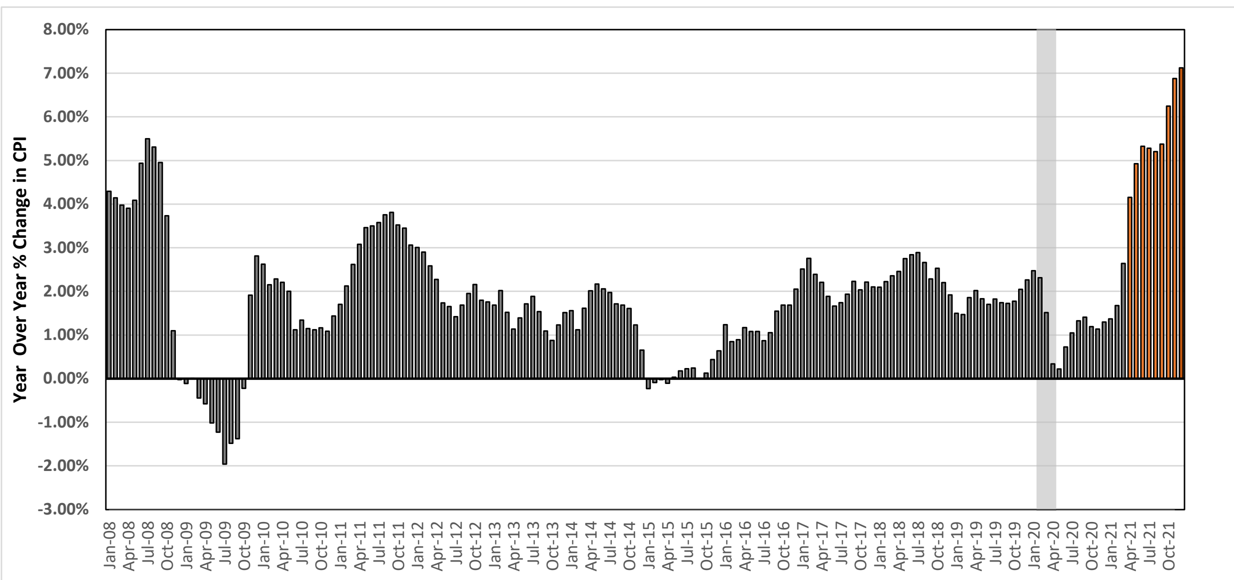
[12] FOMC Meeting Press Conference, Transcript of Chair Powell's Opening Statement (Dec. 15, 2021), at 4.
[13] Barron's, Powell Says Balance Sheet Run-Off Maybe Later This Year, Inflation to Persist into Mid-2022, January 11, 2022.
[14] Callum Keown,*Bond Yields Keep Rising. Goldman Sachs Now Sees 4 Rate Hikes in 2022.* Barron's, (Jan. 10, 2022) *available at* https://www.barrons.com/articles/things-to-know-today-51641808668?mod=BRNS_ENG_NAS_EML_BULLETIN_AUTO_NAH%3Fmod.

that the Federal Reserve may even need to raise rates five times in 2022.[15]

Q. Is the increase in inflation significant?

A. Yes. As shown in Figure 2, the year-over-year (YOY) change in the Consumer Price Index (CPI) published by the Bureau of Labor Statistics has increased steadily in 2021 rising from 1.37 percent in January to 7.12 percent in December. The 7.12 percent YOY in the CPI in December 2021 is the largest 12-month increase since 1982 and is significantly greater than any level seen since January 2008.

Figure 2: CPI YOY Percent Change, January 2008 – December 2021[16]



Q. What are the expectations for inflation over the near-term?

A. Investors expect inflation to persist into 2022. For example, Goldman Sachs forecasts consumer price inflation excluding food and energy costs to still be above 4 percent when the Federal Reserve ends their tapering of bond purchases in 2022.[17] Similarly,

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[15] Callum Keown, Powell's Senate Hearing Holds the Key for Markets. Expect the Unexpected, (Jan. 11, 2022).
[16] Bureau of Labor Statistics, shaded area indicates the COVID-19 pandemic recession.
[17] Simon Kennedy, *Goldman Now Sees Fed Hiking Rates in July as Inflation Lingers.* Bloomberg.com, Bloomberg (Oct. 30. 2021) *available at* https://www.bloomberg.com/news/articles/2021-10-30/goldman-now-sees-fed-hiking-rates-in-july-as-inflation-lingers.

respondents to the recent CNBC Fed Survey, indicated the CPI is expected to rise 4.0 percent in 2022 and 3.0 percent in 2023 which is well above the Federal Reserve's long-term target of 2 percent.[18] Finally, Kiplinger recently noted the following regarding inflation expectations over the near-term:

> While the inflation rate is expected to drop as the year progresses, this month's price report is likely to get the Federal Reserve to make its first interest rate hike in four years in March, with three more hikes after that (in June, September and December). While the Fed believes that inflation will fall, it is concerned that today's rising costs may become a self-fulfilling prophecy, as businesses expect to be able to continue raising prices, and workers continue to expect rising wages.[19]

Q. What effect will inflation have on long-term interest rates?

A. Inflation and the Federal Reserve's normalization of monetary policy will likely result in increases in long-term interest rates. Specifically, inflation reduces the purchasing power of the future interest payments an investor expects to receive over the duration of the bond. This risk increases the longer the duration of the bond. As a result, if investors expect increased levels of inflation, they will require higher yields to compensate for the increased risk of inflation which means interest rates will likely increase.

Q. What views have equity analysts expressed about the economic conditions and the yields on long-term government bonds over the near-term?

A. Several equity analysts have noted that they expect economic conditions to continue to improve and thus the yields on long-term government bonds to continue to increase

[18] Steve Liesman, *The Fed will halt asset purchases by March and hike rates in June, CNBC survey predicts.* CNBC, (Dec. 14, 2021) *available at* https://www.cnbc.com/2021/12/14/the-fed-will-halt-asset-purchases-by-march-and-hike-rates-in-june-cnbc-survey-predicts.html.
[19] David Payne, *Inflation Stays Hot for Now*, Kiplinger (Jan. 13, 2022).

through the end of 2022. As shown in Figure 3, according to six different equity analysts, the yield on the 10-year Treasury Bond is expected to range from 1.75 percent to 2.50 percent in 2022, which is 26 to 101 basis points greater than the current 30-day average yield on the 10-year Treasury Bond as of December 31, 2021, of 1.49 percent. Specifically, Morgan Stanley recently noted the following regarding the expectation for long-term government bond yields in 2022:

> Continued strong growth in 2022, alongside receding but above-target inflation, keeps the Fed patient, yet gradually moving toward rate hikes, and keeps Treasury yields moving higher.[20]

Figure 3: Equity Analysts Forecast of the 10-year Treasury Yield[21]

Bank	10-year U.S. Treasury Yield	
	30-day Average as of December 31, 2021	**2022 Forecast**
Barclays	1.49%	1.75%
Morgan Stanley	1.49%	2.10%
Goldman Sachs	1.49%	2.00%
JP Morgan	1.49%	2.10%
Wells Fargo Investment Institute	1.49%	2.00% - 2.50%
Amundi	1.49%	1.80% - 2.00%

Q. Have you considered any additional indicators that may imply long-term interest rates are expected to increase?

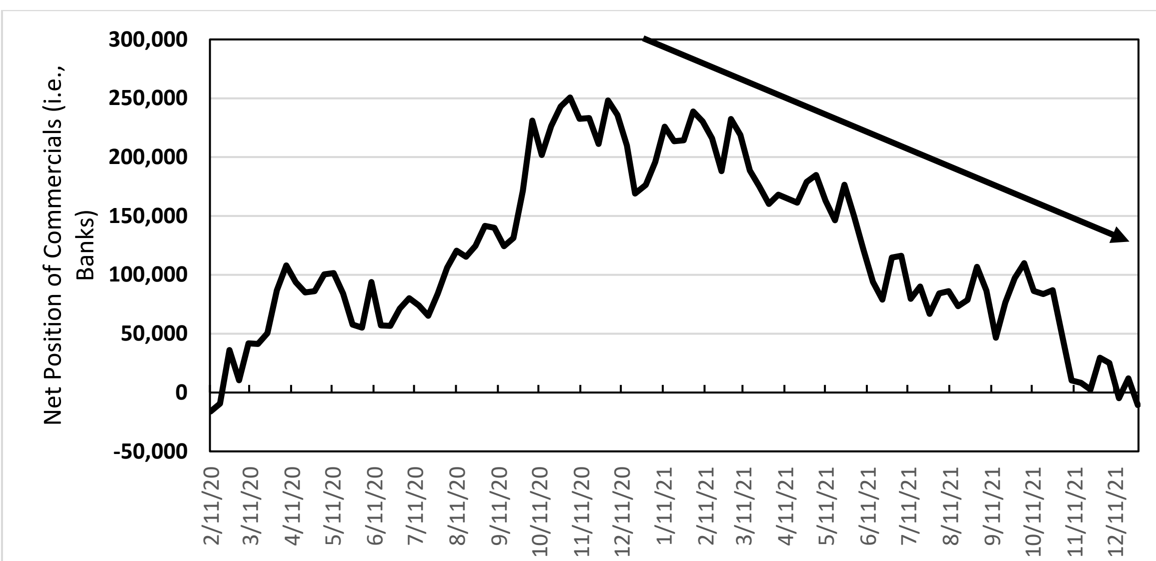
A. Yes; I considered the net position of commercials (*i.e.*, banks) in U.S. Treasury Bond futures contracts as reported in the Commitment of Traders Report produced by the Commodity Futures Trading Commission. A net position is defined as the total number of long positions in a futures contract minus the total number of short

[20] *Factbox: Wall Street Forecasts for the U.S. Dollar and 10-Year Treasury Yield in 2022.*, Reuters, Thomson Reuters (Nov. 18, 2021) *available at* https://www.reuters.com/markets/us/wall-street-forecasts-us-dollar-10-year-treasury-yield-2022-2021-11-18/

[21] *Factbox: Wall Street Forecasts for the U.S. Dollar and 10-Year Treasury Yield in 2022.*, Reuters, Thomson Reuters (Nov. 18, 2021) *available at* https://www.reuters.com/markets/us/wall-street-forecasts-us-dollar-10-year-treasury-yield-2022-2021-11-18/.

positions in a futures contract. A long position means that an investor agrees to purchase an asset in the future at a specified price today and therefore profits if the price of the underlying asset increases. Conversely, a short position is when an investor agrees to sell an asset at a time in the future at a specified price today and profits if the price of the asset declines. Therefore, if banks are increasing the number of short positions and thus have a declining net position, the banks are assuming that the price of the asset will decline. As shown in Figure 4, the net position of banks in U.S. Treasury Bonds has been decreasing since the end of 2020. Therefore, banks are forecasting a decrease in the price of long-term government bonds and thus are projecting that the yields (which are inversely related to the price) will increase over the near-term.

Figure 4: Net Position of Commercials (*i.e.*, Banks) in U.S. Treasury Bond Futures Contracts[22]



[22] Commitment of Traders Report, as of Dec. 31, 2021, *available at* https://www.cftc.gov/MarketReports/CommitmentsofTraders/HistoricalCompressed/index.htm

Q. Are utility share prices correlated to changes in the yields on long-term government bonds?

A. Yes; 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. For example, Goldman Sachs and Deutsche Bank recently examined the sensitivity of share prices of different industries to changes in interest rates over the past five years. Both Goldman Sachs and Deutsche Bank found that utilities had one of the strongest negative relationships with bond yields (*i.e*., increases in bond yields resulted in the decline of utility share prices).[23] Charles Schwab also recently noted the inverse relationship between interest rates and utility share prices and concluded that the utility sector tends to underperform during periods of economic growth when interest rates are higher.[24]

Q. How do equity analysts expect utilities to underperform in an increasing interest rate environment?

A. Equity analysts project that utilities will continue to underperform the broader market as interest rates increase. For example, in a recent article, Barron's conducted its Big Money poll of professional investors regarding the outlook for the next 12 months. Approximately 60 percent of respondents projected the yield on the 10-year Treasury Bond will be 2.00 percent or greater at the end of the next 12 months which is an

[23] Justina Lee, *Wall Street Is Rethinking the Treasury Threat to Big Tech Stocks.*, Bloomberg.com (Mar. 11, 2021) available at http://www.bloomberg.com/news/articles/2021-03-11/wall-street-is-rethinking-the-treasury-threat-to-big-tech-stocks.
[24] Charles Schwab, Schwab Sector Views: Too Early for Defensive Positioning (Aug. 19, 2021).

increase from the current 30-day average 10-year Treasury Bond yield as of December 31, 2021 of 1.49 percent.[25]

Other equity analysts concur with this conclusion. Fidelity recently recommended underweighting the utility sector and noted that "[w]eak fundamentals and high valuations could be headwinds for utilities and real estate, especially if rates increase."[26] In its 2022 Outlook, Wells Fargo classified the utility sector as "most unfavorable" as economic growth continues to rebound and interest rates increase.[27] Finally, Charles Schwab has classified the utilities sector overall as "Underperform," noting negatives for the sector that include "interest rates are expected to recover from recent decline" and "economic recovery makes the sector less attractive, relative to other sectors."[28]

Q. What is the significance of the inverse relationship between interest rates and utility share prices in the current market relative to the cost of equity in this proceeding?

A. As discussed above, the economy is currently in the recovery phase of the business cycle, which is characterized by improving economic growth, increasing inflation, and increasing interest rates. If interest rates increase as expected, then the share prices of utilities will decline. If the share prices of utility stocks decline, then the DCF model, which relies on historical averages of share prices, is likely to understate

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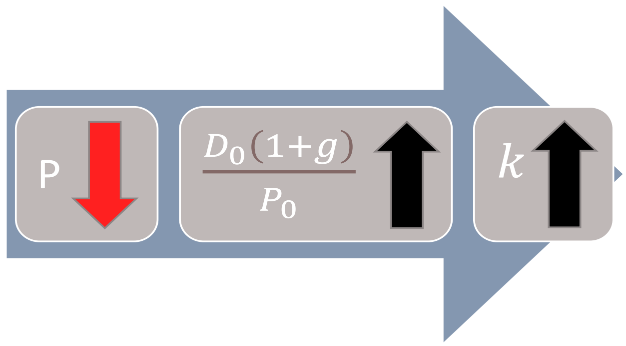
[25] Nicholas Jasinski, *Stocks Are Still the Place to Be, Our Exclusive Big Money Poll Finds.*, Barron's (Oct. 16, 2021) *available at* https://www.barrons.com/articles/stock-market-covid-economy-outlook-51634312012?mod=hpsubnav&tesla=y.
[26] Fidelity, "Q4 2021 sector scorecard" (Oct. 27, 2021).
[27] Wells Fargo Investment Institute, 2022 Outlook (Dec. 2021).
[28] Charles Schwab, Utilities Sector Rating: Underperform (Dec. 16, 2021).

the cost of equity. Figure 5 summarizes the effect of price on the dividend yield in the Constant Growth DCF model.

Figure 5: The Effect of a Decline in Stock Prices on the Constant Growth DCF Model



A decline in utility stock prices going forward will increase the dividend yields of utility stocks and thus increase the estimate of the cost of equity that would be produced by the Constant Growth DCF model relative to the cost of equity currently produced by the Constant Growth DCF model that relies on historical stock prices. Therefore, this expected change in market conditions supports consideration of the range of ROE results produced by the mean to mean-high DCF results since the mean DCF results would likely understate the cost of equity during the period that the Company's rates will be in effect. Moreover, prospective market conditions warrant consideration of other ROE estimation models such as the CAPM, and Risk Premium which may better reflect expected market conditions. For example, two out of three inputs to the CAPM (*i.e.*, the market risk premium and risk-free rate) are forward-looking.

Q. Have state regulatory commissions considered market events and the utility's ability to attract capital in determining the equity return?

A. Yes. In a recent rate case for Consumers Energy Company, the Michigan Public

Service Commission (Michigan PSC) noted that it is important to consider how a utility's access to capital could be affected in the near-term as a result of market reactions to global events like those that have occurred in the recent past.[29] Specifically, the Michigan PSC stated that:

> [i]n setting the ROE at 9.90%, the Commission believes there is an opportunity for the company to earn a fair return during this period of atypical market conditions. This decision also reinforces the belief, as stated in the Commission's March 29 order, "that customers do not benefit from a lower ROE if it means the utility has difficulty accessing capital at attractive terms and in a timely manner." These conditions still hold true based on the evidence in the instant case. The fact that other utilities have been able to access capital despite lower ROEs, as argued by many intervenors, is also a relevant consideration. *It is also important to consider how extreme market reactions to global events, as have occurred in the recent past, may impact how easily capital will be able to be accessed during the future test period should an unforeseen market shock occur. The Commission will continue to monitor a variety of market factors in future rate cases to gauge whether volatility and uncertainty continue to be prevalent issues that merit more consideration in setting the ROE.*[30]

The Michigan PSC references "global events" and the overall effect the events could have on the ability of a utility to access capital. Consistent with the Michigan PSC's views, it is important to consider current market conditions and the impact of those conditions on the access to and cost of capital, and to position utilities to be able to maintain access in rapidly changing market conditions.

Q. What are your conclusions regarding the effect of current and expected future capital market conditions on the cost of equity for the Company?

A. Over the near-term, investors expect economic growth to continue to rebound and

[29] In the matter of the application of Consumers Energy Company for authority to increase its rates for the generation and distribution of electricity and for other relief, Mich. Pub. Serv. Comm'n, Cause No. U-20697, Order at 165 (Dec. 17, 2020).
[30] *Id.* at 43 (emphasis added).

thus inflation and interest rates to increase. Because the share prices of utilities are inversely correlated to the interest rates, an increase in long-term government bond yields will likely result in a decline in utility share prices which is the reason a number of equity analysts expect the utility sector to underperform over the near-term. The expected underperformance of the utility sector relative to the broader stock market means that DCF models using recent historical data likely underestimate investors' required return over the period that rates will be in effect. This change in market conditions also support the use of other ROE estimation models such as the CAPM, and Risk Premium which may better reflect expected market conditions.

VI. PROXY GROUP SELECTION

Q. Why have you used groups of proxy companies to estimate the cost of equity for PacifiCorp?

A. In this proceeding, I am estimating the cost of equity for PacifiCorp, a rate-regulated subsidiary of BHE. Since the ROE is a market-based concept and given the fact PacifiCorp's operations in Oregon do not make up the entirety of a publicly-traded entity, it is necessary to establish a group of companies that is both publicly-traded and comparable to PacifiCorp in certain fundamental business and financial respects to serve as its "proxy" for purposes of estimating the cost of equity.

Even if PacifiCorp's Oregon electric utility operations made up the entirety of a publicly-traded entity, it is possible that transitory events could bias its market value over a given time period. A significant benefit of using a proxy group is that it mitigates the effects of anomalous events that may be associated with any one company. The proxy companies used in my analyses all possess a set of operating and financial risk characteristics that are substantially comparable to PacifiCorp, and, therefore, provide a reasonable basis to derive and estimate the appropriate ROE for the Company.

Q. Please provide a brief profile of PacifiCorp.

A. PacifiCorp is an indirect, wholly owned subsidiary of BHE. PacifiCorp provides electric utility service to approximately 2.0 million residential, commercial and industrial customers in California, Idaho, Oregon, Utah, Washington, and Wyoming.[31] In Oregon, PacifiCorp provides electric service to approximately 630,000 residential, commercial, and industrial customers.[32] As of December 31, 2021, PacifiCorp owned net utility electric plant of approximately $22.4 billion.[33] PacifiCorp's electric operations in Oregon represented 23.8 percent of PacifiCorp's electric sales in 2020.[34] PacifiCorp currently has an investment grade long-term rating of A (Outlook: Stable) from Standard & Poor's (S&P) and A3 (Outlook: Stable) from Moody's.[35] PacifiCorp's current long-term issuer credit ratings are shown in Figure 6:

Figure 6: PacifiCorp Credit Ratings[36]

Credit Rating Agency	Rating	Outlook
Standard & Poor's	A	Stable
Moody's Investors Service	A3	Stable

[31] Berkshire Hathaway Energy Co., 2020 Form 10-K at 3.
[32] Company provided data.
[33] Company provided data.
[34] Berkshire Hathaway Energy Co., 2020 Form 10-K at 3.
[35] S&P Capital IQ accessed Jan. 18, 2022, and MOODY'S INVESTOR SERVICE, *Credit Opinion,* PacifiCorp (June 25, 2020).
[36] S&P GLOBAL RATINGS, RATINGS DIRECT, PacifiCorp (April 5, 2021) at 5, MOODY'S INVESTORS SERVICE, *Credit Opinion,* PacifiCorp (June 25, 2020).

Q. How did you select the companies in your proxy group?

A. I began with the group of 36 companies that Value Line classifies as Electric Utilities and applied the following screening criteria to select companies that:

- pay consistent quarterly cash dividends, because companies that do not cannot be analyzed using the Constant Growth DCF model;
- have investment grade long-term issuer ratings from S&P and/or Moody's;
- are covered by at least two utility industry analysts;
- have positive long-term earnings growth forecasts from at least two utility industry equity analysts;
- own regulated generation assets that are in ratebase;
- have more than five percent of owned regulated generation capacity from regulated coal-fired power plants;
- derive more than 60.00 percent of their total operating income from regulated operations;
- derive more than 60.00 percent of regulated operating income from gas distribution operations; and;
- were not parties to a merger or transformative transaction during the analytical periods relied on.

Q. Did you exclude any other companies from the proxy group?

A. Yes. Similar to the reason that I exclude transformative transactions; because the stock price can be affected by one-time events, I also excluded Pinnacle West Capital Corporation from the proxy group. The stock price of Pinnacle West Capital Corporation decreased approximately 24 percent over a two-month period from

October through November 2021 resulting from a negative regulatory decision for its largest operating company, Arizona Public Service Company. Therefore, I have excluded this company from the proxy group.

Q. What is the composition of your proxy group?

A. The screening criteria just discussed results in a proxy group consisting of the companies shown in Figure 7 (and also in Exhibit PAC/303).

Figure 7: Proxy Group

Company	Ticker
ALLETE, Inc.	ALE
Alliant Energy Corporation	LNT
Ameren Corporation	AEE
American Electric Power Company, Inc.	AEP
Avista Corporation	AVA
CMS Energy Corporation	CMS
Duke Energy Corporation	DUK
Entergy Corporation	ETR
Evergy, Inc.	EVRG
IDACORP, Inc.	IDA
NextEra Energy, Inc.	NEE
NorthWestern Corporation	NWE
Otter Tail Corporation	OTTR
Portland General Electric Company	POR
Southern Company	SO
Xcel Energy Inc.	XEL

VII. COST OF EQUITY ESTIMATION

Q. Please briefly discuss the ROE in the context of a regulated utility.

A. The regulatory construct requires that the regulatory agency, acting as a substitute for the competitive market, establish a ROR for the company that is commensurate with the ROR expected in the market for investments of similar risk. There can be adjustments to the ROE to reflect specific performance (*e.g.*, positive adjustments recognizing strong management performance, cost savings and other important operational metrics, or negative adjustments reflecting poor performance in similar metrics). Absent any adjustments for these types of performance measures, the base ROE is intended to reflect the return that investors require in order to invest in utility assets rather than investing in enterprises of comparable risk in the industry or competitive market.

The overall ROR for a regulated utility includes both the cost of debt and the cost of equity and is based on its weighted average cost of capital, whereby the costs of the individual sources of capital are weighted by their proportion in the capital structure. While the cost of debt and preferred stock can be directly observed, the cost of equity is market-based and, therefore, must be estimated based on observable market data.

Q. How is the required ROE determined?

A. The required ROE is estimated by using multiple analytical techniques that rely on market data to quantify investors' return requirements, adjusted for certain incremental costs and risks. Quantitative models produce a range of reasonable results from which the market-required ROE is selected. That selection must be based on a comprehensive review of relevant data and information, but it does not necessarily lend itself to a strict mathematical solution. The key consideration in determining the cost of equity is to ensure that the methodologies employed reasonably reflect investors' views of the financial markets in general and of the subject company (in the context of the proxy group) in particular.

Q. What methods did you use to estimate PacifiCorp's cost of equity?

A. I considered the results of the Constant Growth DCF model, the Multi-Stage DCF model, the CAPM, and the Bond Yield Plus Risk Premium approach. As discussed in more detail below, a reasonable ROE estimate considers alternative methodologies, observable market data, and the reasonableness of their individual and collective results.

A. Importance of Multiple Analytical Approaches

Q. Why is it important to use more than one analytical approach?

A. Because the cost of equity is not directly observable, it must be estimated based on both quantitative and qualitative information. When faced with the task of estimating the cost of equity, analysts and investors are inclined to gather and evaluate as much relevant data as reasonably can be analyzed. Several models have been developed to estimate the cost of equity, and I use multiple approaches to estimate the cost of equity. As a practical matter, however, all of the models available for estimating the cost of equity are subject to limiting assumptions or other methodological constraints. Consequently, many well-regarded finance texts recommend using multiple approaches when estimating the cost of equity. For example, Copeland, Koller, and Murrin[37] suggest using the CAPM and Arbitrage Pricing Theory model, while Brigham and Gapenski[38] recommend the CAPM, DCF, and Bond Yield Plus Risk Premium approaches. Consistent with the *Hope* finding, it is the analytical result, not the methodology employed, which is controlling in arriving at ROE determinations.

[37] TOM COPELAND, TIM KOLLER AND JACK MURRIN, VALUATION: MEASURING AND MANAGING THE VALUE OF COMPANIES, AT 214 (3rd Ed 2000).
[38] EUGENE BRIGHAM, LOUIS GAPENSKI, FINANCIAL MANAGEMENT: THEORY AND PRACTICE at 341 (7th ed. 1994).

Q. Is it important given the current market conditions to use more than one analytical approach?

A. Yes. Low interest rates and the effects of the investor "flight to quality" associated with the pandemic can be seen in relatively high utility share valuations compared to historical levels and to the broader market. Higher utility stock valuations produce lower dividend yields and result in lower cost of equity estimates from a DCF analysis. Lower interest rates also affect the CAPM in two ways: (1) the risk-free rate is lower that it is expected to be going forward; and (2) because the market risk premium is a function of interest rates (*i.e.*, it is the return on the broad stock market less the risk-free interest rate), the market risk premium is expected to be higher when interest rates are lower. Therefore, it is important to use multiple analytical approaches to moderate the effect of the current low interest rate environment on the ROE estimates for the proxy group, and where possible, consider using projected market data in the models to estimate the return for the forward-looking period.

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

A. Yes. In previous cases, the Commission has 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. Specifically, in the Company's last case, the Commission considered the results of the DCF, CAPM and Risk Premium approaches:

> The Commission has previously accepted CAPM as a "useful and reliable addition to the DCF results" for determining cost of equity in certain cases. While we have historically rejected the risk premium analysis as unconventional and because it had not been

> accepted by other regulatory agencies, we note that FERC now gives equal consideration to DCF, CAPM and risk premium results.[39]

Further, the Commission recognized that no one party's application of any model is correct or certain. In that proceeding, the Commission considered the range of results established using the DCF model, the CAPM and the risk premium models. Further, the Commission recognized that the effects of the pandemic caused additional uncertainty in the assumptions used in the models. In addition, the Commission recognized incremental risk associated with the Company's capital investment plan and further recognized the relationship between the ROE and equity ratio.[40]

B. Constant Growth DCF Model

Q. Please describe the DCF approach.

A. The DCF approach is based on the theory that a stock's current price represents the present value of all expected future cash flows. In its most general form, the DCF model is expressed as follows:

$$P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \ldots + \frac{D_\infty}{(1+k)^\infty}$$

Where P_0 represents the current stock price, $D_1 \ldots D_\infty$ are all expected future dividends, and k is the discount rate, or required ROE. Equation [1] is a standard present value calculation that can be simplified and rearranged into the following form:

$$k = \frac{D_0(1+g)}{P_0} + g$$

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[39] Order No. 20-476 at 30.
[40] *Id.*, at 30-31.

Equation [2] is often referred to as the Constant Growth DCF model in which the first term is the expected dividend yield and the second term is the expected long-term growth rate.

Q. What assumptions are required for the Constant Growth DCF model?

A. The Constant Growth DCF model requires the following assumptions: (1) a constant growth rate for earnings and dividends; (2) a stable dividend payout ratio; (3) a constant price-to-earnings (P/E) ratio; and (4) a discount rate greater than the expected growth rate. To the extent any of these assumptions is violated, considered judgment and/or specific adjustments should be applied to the results.

Q. What market data did you use to calculate the dividend yield in your Constant Growth DCF model?

A. The dividend yield in my Constant Growth DCF model is based on the proxy group companies' current annual dividend and average closing stock prices over the 30-, 90-, and 180-trading days ended December 31, 2021.

Q. Did you make any adjustments to the dividend yield to account for periodic growth in dividends?

A. Yes. Since utility companies tend to increase their quarterly dividends at different times throughout the year, it is reasonable to assume that dividend increases will be evenly distributed over calendar quarters. Given that assumption, it is reasonable to apply one-half of the expected annual dividend growth rate for purposes of calculating the expected dividend yield component of the DCF model. This adjustment ensures that the expected first year dividend yield is, on average, representative of the coming 12-month period, and does not overstate the aggregated dividends to be paid during that time.

Q. Why is it important to select appropriate measures of long-term growth in applying the DCF model?

A. In its Constant Growth form, the DCF model (*i.e.*, Equation [2]) assumes a single long-term growth rate in perpetuity. In order to reduce the long-term growth rate to a single measure, one must assume that the dividend payout ratio remains constant and that Earnings Per Share (EPS), dividends per share, and book value per share all grow at the same constant rate. Over the long run, however, dividend growth can only be sustained by earnings growth. Therefore, it is important to incorporate a variety of sources of long-term earnings growth rates into the Constant Growth DCF model.

Q. What sources of long-term growth rates did you rely on in your Constant Growth DCF model?

A. As shown in Exhibit PAC/304, my Constant Growth DCF model incorporates three sources of long-term growth rates: (1) consensus long-term earnings growth estimates from Zacks Investment Research; (2) consensus long-term earnings growth estimates from Thomson First Call (provided by Yahoo! Finance); and (3) long-term earnings growth estimates from Value Line Investment Survey (Value Line).

Q. How did you calculate the range of results for the Constant Growth DCF model?

A. I calculated the low-end result for the Constant Growth DCF model using the lowest projected earnings growth rate (*i.e.*, the lowest of First Call, Zacks, and Value Line) for each of the proxy group companies. I applied a similar approach to calculate the high-end result for the Constant Growth DCF model by using the highest projected earnings growth rate of the three sources for each proxy group company. The median results of the Constant Growth DCF model were calculated using the mean growth rate of the three sources for each proxy group company as well as the low and high growth rate scenarios. Once the results for each proxy group company were calculated, I then relied on the median of the results as the measure of central tendency for purposes of my analysis, referring to each of the results as the "median low," "median" and "median high" results.

C. Multi-Stage DCF Model

Q. What other forms of the DCF model have you considered?

A. Consistent with Commission precedent, I also considered the results of a Multi-Stage form of the DCF model. As with the Constant Growth DCF model, the Multi-Stage form defines the cost of equity as the discount rate that sets the current price equal to the discounted value of future cash flows.

Q. Has the Commission expressed a preference for the results of the Multi-Stage DCF model?

A. Yes, the Commission has indicated that it prefers the results of the Multi-Stage DCF model. For example, in its recent order in PacifiCorp's last proceeding, the Commission stated:

> This Commission has primarily relied upon the multi-stage DCF model in determining a reasonable range of ROE, and in this case we are not persuaded to depart from that approach. In this case, we will also consider the results of the CAPM and risk-premium models presented by the parties to confirm the reasonableness of that range and of the ROE authorized in this case.[41]

[41] Order No. 20-476 at 30.

While I agree that the Multi-Stage DCF model is one of the methods among investors and regulators, I also agree with the Commission that it is reasonable to consider the results of other models to confirm the reasonableness of the results of that model. In the current market environment, it is the high valuations and low dividend yields for utility stocks that are causing the DCF model to produce unreliable results, not the earnings growth rates for utility companies, which have generally remained within the traditional range of five to seven percent. Under more normal market conditions, the single-stage form of the DCF model generally produces reasonable and reliable estimates of the cost of equity for companies in stable, mature industries, such as regulated utilities.

Q. How does the Multi-Stage form of the DCF model differ from the Constant Growth form of the DCF model?

A. The Multi-Stage DCF model, which is an extension of the Constant Growth form, enables the analyst to specify different growth rates over multiple stages. The Multi-Stage DCF model allows for a gradual transition from the first-stage growth rate to the long-term growth rate, thereby avoiding the unrealistic assumption that growth changes abruptly between the first and final stages.

Q. Please generally describe the structure of your Multi-Stage DCF model.

A. The Multi-Stage DCF model sets a company's current stock price equal to the present value of future cash flows received over three "stages." In all three stages, cash flows are equal to the annual dividend payments that stockholders receive. Stage One is a short-term growth period that consists of the first five years; Stage Two is a transition period from the short-term growth rate to the long-term growth rate (i.e., years six through 10); and Stage Three is a long-term growth period that begins in year 11 and continues in perpetuity (i.e., year 200). The ROE is then calculated as the ROR that results from the initial stock investment and the dividend payments over the analytical period.

Q. Please summarize the EPS growth rates used in your Multi-Stage DCF model.

A. As shown in Exhibit PAC/305, I began with the current annualized dividend as of December 31, 2021 for each proxy group company. In the first stage of the model, the current annualized dividend is escalated based on the average of the three- to five-year earnings growth estimates reported by Zacks, Thomson First Call, and Value Line. For the third stage, I relied on long-term projected growth in GDP. The second stage growth rate is a transition from the first stage growth rate to the long-term growth rate on a geometric average basis.

Q. How did you calculate the long-term GDP growth rate?

A. As shown in Exhibit PAC 306, the long-term growth rate of 5.49 percent is based on real GDP growth rate of 3.13 percent from 1929 through 2020,[42] and a projected inflation rate of 2.28 percent. The projected inflation rate is based on three measures: (1) the average long-term projected growth rate in the CPI of 2.20 percent;[43] (2) the compound annual growth rate of the CPI for all urban consumers for 2031-2050 of 2.27 percent as projected by the Energy Information Administration (EIA); and (3) the compound annual growth rate of the GDP chain-type price index for 2031-2050 of 2.37 percent, also reported by the EIA.[44]

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[42] U.S. Department of Commerce, Bureau of Economic Analysis, National Income and Product Accounts Tables, Table 1.1.1, December 31, 2021.
[43] Blue Chip Financial Forecasts, Vol. 40, No. 12, December 1, 2021, at 14.
[44] U.S. Energy Information Administration, Annual Energy Outlook 2021, Table 20, Macroeconomic Indicators.

Q. Do the assumptions used in the Multi-Stage DCF model address the effect of low dividend yields on the DCF results?

A. No, they do not. While the Multi-Stage DCF model provides for changes in growth over time, it does not address the abnormally low dividend yields for utility stocks and the effect of those low dividend yields on the DCF model, specifically the understated ROEs that result from the use of these assumptions. For that reason, I have also considered the results of risk-premium based methodologies, which I will discuss later in my direct testimony.

D. Discounted Cash Flow Model Results

Q. How did you calculate the range of results for the Constant Growth and Multi-Stage DCF models?

A. I calculated the low result for both DCF models using the minimum growth rate (*i.e.*, the lowest of the First Call, Zacks, and Value Line earnings growth rates) for each of the proxy group companies. Thus, the low result reflects the minimum DCF result for the proxy group. I used a similar approach to calculate the high results, using the highest growth rate for each proxy group company. The mean results were calculated using the average growth rates from all sources.

Q. What are the results of your DCF analyses?

A. Figure 8 summarizes the results of my DCF analyses. As shown in Figure 8, the median Constant Growth DCF results range from 9.35 percent to 9.50 percent and the median high results range from 10.28 percent to 10.37 percent. The median Multi-

Stage DCF results range from 9.45 percent to 9.50 percent and the median high results are in the range of 9.73 percent to 9.81 percent.

Figure 8: Discounted Cash Flow Results

	Mean Low	Mean	Mean High
Median Constant Growth DCF[45]			
30-Day Average	8.57%	9.44%	10.34%
90-Day Average	8.62%	9.50%	10.37%
180-Day Average	8.63%	9.35%	10.28%
Median Multi-Stage DCF[46]			
30-Day Average	9.01%	9.45%	9.79%
90-Day Average	9.03%	9.50%	9.81%
180-Day Average	9.02%	9.48%	9.73%

Q. What are your conclusions about the results of the DCF models?

A. As discussed previously, one primary assumption of the DCF models is a constant P/E ratio. That assumption is heavily influenced by the market price of utility stocks. Since utility stocks are expected to underperform the broader market over the near-term as interest rates increases, it is important to consider the results of the DCF models with caution. This means that the results of the DCF models, which rely on historical stock prices, are below where they would be expected to be going forward during the period in which the rates for the Company will be in effect. Therefore, while I have given weight to the results of the DCF models, my recommendation also gives weight to the results of other ROE estimation models.

E. CAPM Analysis

Q. Please briefly describe the Capital Asset Pricing Model.

A. The CAPM is a risk premium approach that estimates the cost of equity for a given

[45] *See* Exhibit PAC/304.
[46] *See* Exhibit PAC/305.

security as a function of a risk-free return plus a risk premium to compensate investors for the non-diversifiable or "systematic" risk of that security.[47] This second component is the product of the market risk premium and the Beta coefficient, which measures the relative riskiness of the security being evaluated.

The CAPM is defined by four components, each of which must theoretically be a forward-looking estimate:

$$K_e = r_f + \beta(r_m - r_f)$$

Where:

K_e = the required market ROE;

β = Beta coefficient of an individual security;

r_f = the risk-free ROR; and

r_m = the required return on the market as a whole.

In this specification, the term (rm – rf) represents the Market Risk Premium. According to the theory underlying the CAPM, since unsystematic risk can be diversified away, investors should only be concerned with systematic risk. Systematic risk is measured by Beta, which is a measure of the volatility of a security as compared to the overall market. Beta is defined as:

$$\beta = \frac{Covariance(r_e, r_m)}{Variance(r_m)} \quad [4]$$

The variance of the market return (i.e., Variance (r_m)) is a measure of the uncertainty of the general market. The covariance between the return on a specific security and

[47] Systematic risk is the risk inherent in the entire market or market segment. This form of risk cannot be diversified away using a portfolio of assets. Non-systematic risk is the risk of a specific company that can be mitigated through portfolio optimization.

the general market (*i.e.*, Covariance (r_e, r_m)) reflects the extent to which the return on that security will respond to a given change in the general market return. Thus, Beta represents the risk of the security relative to the general market.

Q. What risk-free rate did you use in your CAPM analysis?

A. I relied on three sources for my estimate of the risk-free rate: (1) the current 30-day average yield on 30-year Treasury bonds of 1.87 percent;[48] (2) the projected 30-year Treasury yield for Q2 2022–Q2 2023 of 2.52 percent;[49] and (3) the average projected 30-year Treasury bond yield for the period 2022 through 2026 of 3.40 percent.[50]

Q. Would you place more weight on one of these scenarios?

A. Yes. Based on current market conditions, I place more weight on the results of the projected yields on the 30-year Treasury bonds. As discussed previously, the estimation of the cost of equity in this case should be forward-looking because it is the return that investors would receive over the future rate period. Therefore, the inputs and assumptions used in the CAPM analysis should reflect the expectations of the market at that time. While I have included the results of a CAPM analysis that relies on a current 30-day average risk-free rate, this analysis fails to take into consideration the effect of the market's expectations for interest rate increases on the cost of equity.

Q. What Beta coefficients did you use in your CAPM analysis?

A. As shown in Exhibit PAC/307, I used the Beta coefficients for the proxy group companies as reported by Bloomberg and Value Line. The Beta coefficients reported

[48] Bloomberg Professional as of December 31, 2021.
[49] Blue Chip Financial Forecasts, Vol. 41, No. 1, January 1, 2022, at 2.
[50] Blue Chip Financial Forecasts, Vol. 40, No. 12, December 1, 2021, at 14.

by Bloomberg are calculated using 10 years of weekly returns relative to the S&P 500 Index. The Beta coefficients reported by Value Line are calculated based on five years of weekly returns relative to the New York Stock Exchange Composite Index. Additionally, as shown in Exhibit PAC/307, I also considered an additional CAPM analysis that relies on the long-term average Beta coefficient reported by Value Line for the companies in my proxy group from 2011 through 2021.

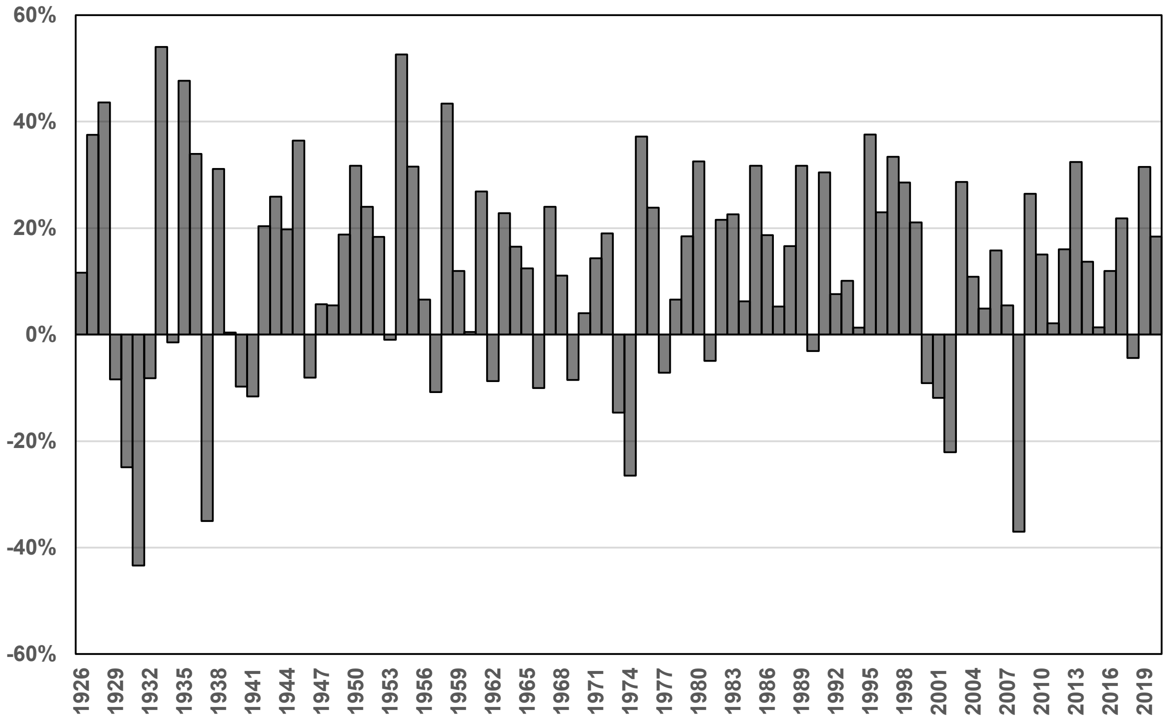
Q. How did you estimate the Market Risk Premium in the CAPM?

A. I estimated the market risk premium as the difference between the implied expected equity market return and the risk-free rate. The expected return on the S&P 500 Index is calculated using the Constant Growth DCF model discussed earlier in my testimony for the companies in the S&P 500 Index for which dividend yields and Value Line long-term earnings projections are available. In addition, I exclude those companies whose earnings projections are either greater than 20.00 percent or lower than 0.00 percent. As shown in Exhibit PAC/307, based on an estimated market capitalization-weighted dividend yield of 1.48 percent and a weighted long-term growth rate of 11.06 percent, the estimated required market return for the S&P 500 Index is 12.63 percent. The implied market risk premium over the risk-free rates evaluated (*i.e.*, the current, near-term projected and longer-term projected 30-year U.S. Treasury bond yield) ranges from 9.23 percent to 10.76 percent.

Q. How does the expected market return you have calculated compare to observed historical market returns?

A. Given the range of annual equity returns that have been observed over the past century as shown in Figure 9, a current expected market return of 12.63 percent is consistent with the historical returns. In fact, in 49 out of the past 95 years (or approximately 52 percent of the observations), the realized equity return was at least 12.63 percent or greater.

Figure 9: Realized U.S. equity market returns (1926–2020)[51]



Q. What are the results of your CAPM analyses?

A. As shown in Figure 10, my traditional CAPM analysis produces a range of returns from 9.72 percent to 11.47 percent.

[51] Depicts total annual returns on large company stocks, as reported in the 2021 Duff & Phelps SBBI Yearbook.

Figure 10: CAPM Results

	Current Risk-Free Rate (1.87%)	Q2 2022 – Q2 2023 Projected Risk-Free Rate (2.52%)	2023-2027 Projected Risk-Free Rate (3.40%)
CAPM			
Value Line Beta	11.28%	11.36%	11.47%
Bloomberg Beta	10.56%	10.68%	10.85%
Long-term Avg. Beta	9.72%	9.90%	10.14%

F. Bond Yield Plus Risk Premium Analysis

Q. Please describe the Bond Yield Plus Risk Premium approach.

A. In general terms, this approach is based on the fundamental principle that equity investors bear the residual risk associated with equity ownership and therefore require a premium over the return they would have earned as a bondholder. That is, because returns to equity holders have greater risk than returns to bondholders, equity investors must be compensated to bear that risk. Risk premium approaches, therefore, estimate the cost of equity as the sum of the equity risk premium and the yield on a particular class of bonds. In my analysis, I used actual authorized returns for natural gas utility companies as the historical measure of the cost of equity to determine the risk premium.

Q. Are there other considerations that should be addressed in conducting this analysis?

A. Yes. It is important to recognize both academic literature and market evidence indicating that the equity risk premium (as used in this approach) is inversely related to the level of interest rates. That is, as interest rates increase (decrease), the equity risk premium decreases (increases). Consequently, it is important to develop an analysis that: (1) reflects the inverse relationship between interest rates and the equity risk premium; and (2) relies on recent and expected market conditions. Such an analysis can be developed based on a regression of the risk premium as a function of U.S. Treasury bond yields. If authorized ROEs for natural gas utilities serve as the measure of required equity returns and define the yield on the long-term U.S. Treasury bond as the relevant measure of interest rates, the risk premium simply would be the difference between those two points.[52]

Q. Is the Bond Yield Plus Risk Premium analysis relevant to investors?

A. Yes. Investors are aware of ROE awards in other jurisdictions, and they consider those awards as a benchmark for a reasonable level of equity returns for utilities of comparable risk operating in other jurisdictions. Because my Bond Yield Plus Risk Premium analysis is based on authorized ROEs for utility companies relative to corresponding Treasury yields, it provides relevant information to assess the return expectations of investors.

Q. What did your Bond Yield Plus Risk Premium analysis reveal?

A. As shown in Figure 11, from 1992 through December 2021, there was a strong negative relationship between risk premia and interest rates. To estimate that relationship, I conducted a regression analysis using the following equation:

$$RP = a + b(T) \quad [6]$$

Where:

RP = Risk Premium (difference between authorized ROEs and the yield on 30-

[52] *See e.g.*, S. Keith Berry, *Interest Rate Risk and Utility Risk Premia during 1982-93*, MANAGERIAL AND DECISION ECONOMICS, Vol. 19, No. 2 (March 1998) (in which the author used a methodology similar to the regression approach described below, including using allowed ROEs as the relevant data source, and came to similar conclusions regarding the inverse relationship between risk premia and interest rates); *See also* Robert S. Harris, *Using Analysts' Growth Forecasts to Estimate Shareholders Required Rates of Return*, FINANCIAL MANAGEMENT, Spring 1986 at 66.

year U.S. Treasury bonds)

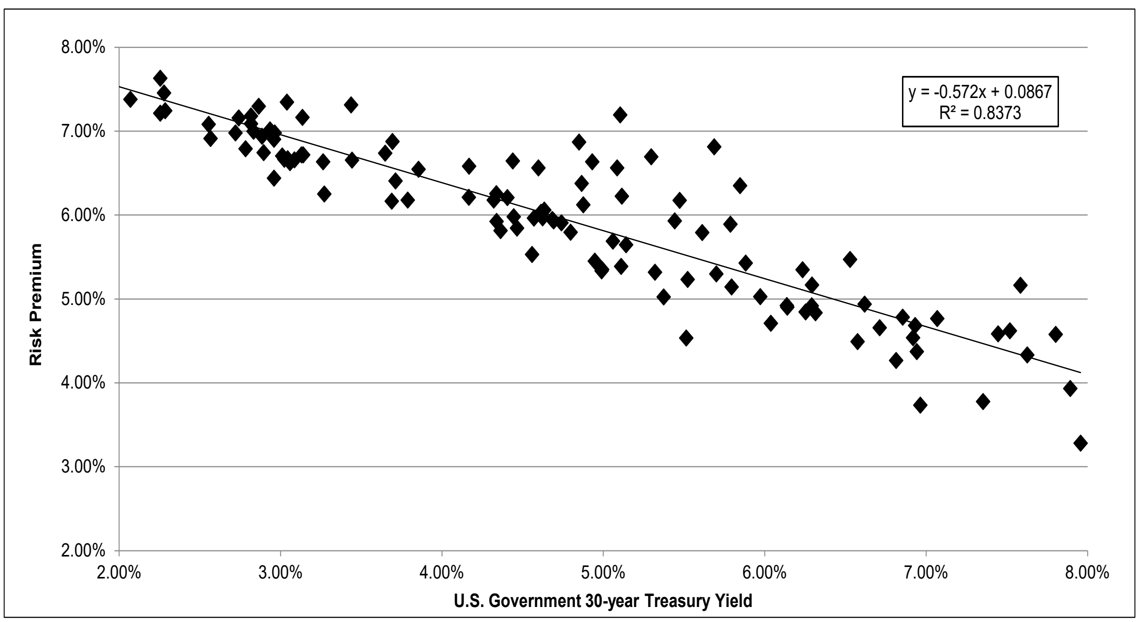
a = intercept term

b = slope term

T = 30-year U.S. Treasury bond yield

Data regarding allowed ROEs were derived from more than 666 vertically integrated electric utility rate cases from 1992 through December 2021 as reported by Regulatory Research Associates (RRA). The equation's coefficients were statistically significant at the 99.00 percent level.

Figure 11: Risk Premium Results



As shown on Exhibit PAC/308, based on the current 30-day average of the 30-year U.S. Treasury bond yield (*i.e.*, 1.87 percent), the risk premium would be 7.61 percent, resulting in an estimated ROE of 9.47 percent. Based on the near-term (Q2 2022–Q2 2023) projected 30-year U.S. Treasury bond yield (*i.e.*, 2.52 percent), the risk premium would be 7.23 percent, resulting in an estimated ROE of 9.75 percent.

Based on longer-term (2023–2027) projected 30-year U.S. Treasury bond yield (*i.e.*, 3.40 percent), the risk premium would be 6.73 percent, resulting in an estimated ROE of 10.13 percent.

Q. How do the results of the Bond Yield Risk Premium analysis inform your recommended ROE for PacifiCorp?

A. In conjunction with the other ROE models that I have discussed, I have considered the results of the Bond Yield Risk Premium analysis in setting my recommended ROE for PacifiCorp. As noted above, investors consider the ROE award of a company when assessing the risk of that company as compared to utilities of comparable risk operating in other jurisdictions. The risk premium analysis accounts for this comparison by estimating the return expectations of investors based on the current and past ROE awards of natural gas utilities across the US.

VIII. REGULATORY AND BUSINESS RISKS

Q. Do the median and mean results of the DCF, CAPM, and Risk Premium analyses for the proxy group provide an appropriate estimate of the cost of equity for PacifiCorp?

A. No. These results provide only a range of the appropriate estimate of PacifiCorp's cost of equity. Several additional factors must be considered when determining where the Company's cost of equity falls within the range of analytical results. These risk factors, discussed below, should be considered with respect to their overall effect on PacifiCorp's risk profile relative to the proxy group.

A. Capital Expenditures

Q. Please summarize PacifiCorp's capital expenditure requirements.

A. PacifiCorp's current projections for 2022 through 2026 include approximately $12.04 billion in capital investments for the period.[53] Based on PacifiCorp's net utility plant of approximately $22.4 billion as of December 31, 2021, the ratio of projected capital expenditures to net utility plant is approximately 53.68 percent.

Q. How is PacifiCorp's risk profile affected by its capital expenditure requirements?

A. As with any utility facing increased capital expenditure requirements, the Company's risk profile may be adversely affected in two significant and related ways: (1) the heightened level of investment increases the risk of under recovery or delayed recovery of the invested capital; and (2) an inadequate return would put downward pressure on key credit metrics.

Q. Do credit rating agencies recognize the risks associated with elevated levels of capital expenditures?

A. Yes. From a credit perspective, the additional pressure on cash flows associated with higher levels of capital expenditures exerts corresponding pressure on credit metrics and, therefore, credit ratings. To that point, S&P explains the importance of regulatory support for large capital projects:

> When applicable, a jurisdiction's willingness to support large capital projects with cash during construction is an important aspect of our analysis. This is especially true when the project represents a major addition to rate base and entails long lead times and technological risks that make it susceptible to construction delays. Broad support for all capital spending is the most credit- sustaining.

[53] Source: Company provided data.

> Support for only specific types of capital spending, such as specific environmental projects or system integrity plans, is less so, but still favorable for creditors. Allowance of a cash return on construction work-in-progress or similar ratemaking methods historically were extraordinary measures for use in unusual circumstances, but when construction costs are rising, cash flow support could be crucial to maintain credit quality through the spending program. Even more favorable are those jurisdictions that present an opportunity for a higher return on capital projects as an incentive to investors.[54]

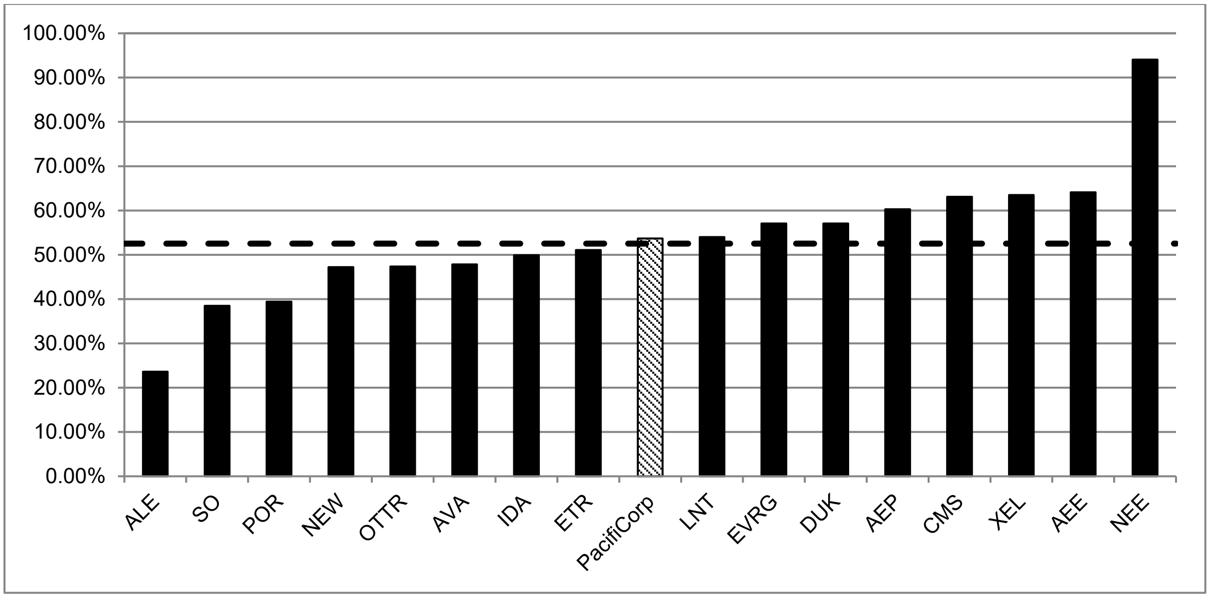
Therefore, to the extent that PacifiCorp's rates do not permit the opportunity to recover its full cost of doing business, the Company will face increased recovery risk and thus increased pressure on its credit metrics.

Q. How do PacifiCorp's capital expenditure requirements compare to those of the proxy group companies?

A. As shown in Exhibit PAC/309 CapEx 1, I calculated the ratio of expected capital expenditures to net utility plant for PacifiCorp and each of the companies in the proxy group by dividing each company's projected capital expenditures for the period from 2022–2026 by its total net utility plant as of December 31, 2020. As shown in Exhibit PAC/309 CapEx 2 (see also Figure 12 below), PacifiCorp's ratio of capital expenditures as a percentage of net utility plant of 53.68 percent is similar to the median of the proxy group companies of 52.53 percent.

[54] S&P GLOBAL RATINGS, Assessing U.S. Investor-Owned Utility Regulatory Environments at 7 (Aug. 10, 2016).

Figure 12: Comparison of Capital Expenditures to Proxy Group Companies



Q. Does PacifiCorp have a capital tracking mechanism to recover the costs associated with capital expenditures between rate cases?

A. Yes. PacifiCorp is authorized to recover costs associated with costs to construct or acquire renewable generation facilities and the associated transmission.

As shown in Exhibit PAC/310, 52.38 percent of the proxy group utilities recover costs through capital tracking mechanisms.

Q. What are your conclusions regarding the effect of the Company's capital spending requirements on its risk profile and cost of capital?

A. PacifiCorp's capital expenditure requirements as a percentage of net utility plant are significant over the next few years and these investments create additional risk for the Company, as noted by the Commission in the Company's last rate proceeding.

B. Regulatory Risks

Q. Please explain how the regulatory environment affects investors' risk assessments.

A. The ratemaking process is premised on the principle that, for investors and companies to commit the capital needed to provide safe and reliable utility service, the subject utility must have the opportunity to recover the return of, and the market-required return on, invested capital. Regulatory authorities recognize that because utility operations are capital intensive, regulatory decisions should enable the utility to attract capital at reasonable terms, and that doing so balances the long-term interests of investors and customers. Utilities must finance their operations and thus require the opportunity to earn a reasonable return on their invested capital to maintain their financial profiles. PacifiCorp is no exception, and in that respect, the regulatory environment is one of the most important factors considered in both debt and equity investors' risk assessments.

From the perspective of debt investors, the authorized return should enable the utility to generate the cash flow needed to meet its near-term financial obligations, make the capital investments needed to maintain and expand its systems, and maintain the necessary levels of liquidity to fund unexpected events. This financial liquidity must be derived not only from internally generated funds, but also by efficient access to capital markets. Moreover, because fixed income investors have many investment alternatives, even within a given market sector, a utility's financial profile must be adequate on a relative basis to ensure its ability to attract capital under a variety of economic and financial market conditions.

Equity investors require that the authorized return be adequate to provide a risk-comparable return on the equity portion of the utility's capital investments. Because equity investors are the residual claimants on the utility's cash flows (*i.e.*, the equity return is subordinate to interest payments), they are particularly concerned with the strength of regulatory support and its effect on future cash flows.

Q. Please explain how credit rating agencies consider regulatory risk in establishing a company's credit rating.

A. Both S&P and Moody's consider the overall regulatory framework in establishing credit ratings. Moody's establishes credit ratings based on four key factors: (1) regulatory framework; (2) the ability to recover costs and earn returns; (3) diversification; and (4) financial strength, liquidity and key financial metrics. Of these criteria, regulatory framework and the ability to recover costs and earn returns are each given a broad rating factor of 25.00 percent. Therefore, Moody's assigns regulatory risk a 50.00 percent weighting in the overall assessment of business and financial risk for regulated utilities.[55]

S&P also identifies the regulatory framework as an important factor in credit ratings for regulated utilities, stating: "One significant aspect of regulatory risk that influences credit quality is the regulatory environment in the jurisdictions in which a utility operates."[56] S&P identifies four specific factors that it uses to assess the credit implications of the regulatory jurisdictions of investor-owned regulated utilities: (1)

[55] MOODY'S INVESTORS SERVICE, Rating Methodology: Regulated Electric and Gas Utilities at 4 (June 23, 2017).
[56] S&P GLOBAL RATINGS, Ratings Direct, U.S. and Canadian Regulatory Jurisdictions Support Utilities' Credit Quality—But Some More So Than Others at 2 (June 25, 2018).

regulatory stability; (2) tariff-setting procedures and design; (3) financial stability; and (4) regulatory independence and insulation.[57]

Q. How does the regulatory environment in which a utility operates affect its access to and cost of capital?

A. The regulatory environment can significantly affect both the access to and cost of capital in several ways. First, the proportion and cost of debt capital available to utility companies are influenced by the rating agencies' assessment of the regulatory environment. As noted by Moody's, "[f]or rate regulated utilities, which typically operate as a monopoly, the regulatory environment and how the utility adapts to that environment are the most important credit considerations."[58] Moody's further highlighted the relevance of a stable and predictable regulatory environment to a utility's credit quality, noting:

> [b]roadly speaking, the Regulatory Framework is the foundation for how all the decisions that affect utilities are made (including the setting of rates), as well as the predictability and consistency of decision-making provided by that foundation."[59]

Q. Have you conducted an analysis of the regulatory framework in Oregon for PacifiCorp's business relative to the jurisdictions in which the companies in your proxy group operate?

A. Yes. I have evaluated the regulatory framework in Oregon based on five factors that are important in terms of providing a regulated utility an opportunity to earn its authorized ROE. These factors are: (1) fuel cost recovery; (2) the test year

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[57] *Id*., at 1.
[58] MOODY'S INVESTOR SERVICES, Rating Methodology: Regulated Electric and Gas Utilities at 6 (Jun. 23, 2017).
[59] *Id*.

convention for ratemaking (*i.e*., forecast vs. historical test year); (3) method for determining rate base for ratemaking (*i.e*., average vs. year-end rate base); (4) use of revenue decoupling or other clauses that mitigate volumetric risk; and (5) prevalence of capital cost recovery between rate cases. The results of my regulatory risk assessment are shown in Exhibit PAC/310 and are summarized below.

1. <u>Fuel Cost Recovery:</u> PacifiCorp has a Power Cost Adjustment Mechanism (PCAM) to recover power costs. However, while traditional fuel cost recovery mechanisms allow all variances between projected fuel costs and actual fuel costs to be recovered from or refunded to customers, the PCAM for PacifiCorp has a deadband that requires PacifiCorp to absorb some portion of the variation in power costs. If the power cost variation falls within this deadband, there will be no power cost rate adjustment. The PCAM has an asymmetrical deadband, which requires that PacifiCorp absorb variances between negative $15 million and positive $30 million. The PCAM also has a sharing mechanism, whereby any power cost variance outside the deadband will be shared 90 percent by customers and 10 percent by PacifiCorp if PacifiCorp earns within plus or minus 100 basis points of its authorized ROE.[60] If PacifiCorp is earning within this range of its authorized ROE, there will be no power cost adjustment for that year. Finally, amortization of deferred amounts in any one year under the PCAM is limited to six percent of PacifiCorp's revenues in the preceding calendar year.[61] As a result, the

[60] Order No. 20-476 at 30 (Dec. 18, 2020).
[61] *In the matter of PacifiCorp, dba Pacific Power Request for a General Rate Revision,* Docket No. UE 246, Order No. 12-493 at 14–15 (Dec. 20, 2012).

PCAM does not fully mitigate the power cost risk for PacifiCorp. This is important to investors because fuel and purchased power costs typically account for 50–60 percent of the total operating costs for a regulated utility. Moreover, according to SNL Financial, there are only nine states (*i.e.*, Arizona, Hawaii, Idaho, Missouri, Montana, Oregon, Vermont, Washington, and Wyoming) that have fuel cost recovery mechanisms with sharing bands. The remaining 41 states either have restructured and the electric utilities do not own generation or have fuel cost recovery mechanisms with a true-up between actual and forecasted fuel costs.

In addition, approximately 88 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.

2. Test Year Convention: PacifiCorp is using a test period that forecasts expenses through the test year 2023, however plant related balances are as of year-end 2022. As shown in Exhibit PAC/310, 50.00 percent of the operating companies held by the proxy group provide service in jurisdictions use a fully or partially forecast test year.

3. Rate Base: The Company's rate base in this proceeding is established using year-end 2022 balances for plant-related rate base, other adjusted rate base balances are based on the 13-month average as of December 31, 2023. Approximately 45 percent of the operating subsidiaries held by the proxy group use year-end rate base, meaning that the rate base includes capital

additions that occurred in the second half of the test year and is more reflective of net utility plant going forward.

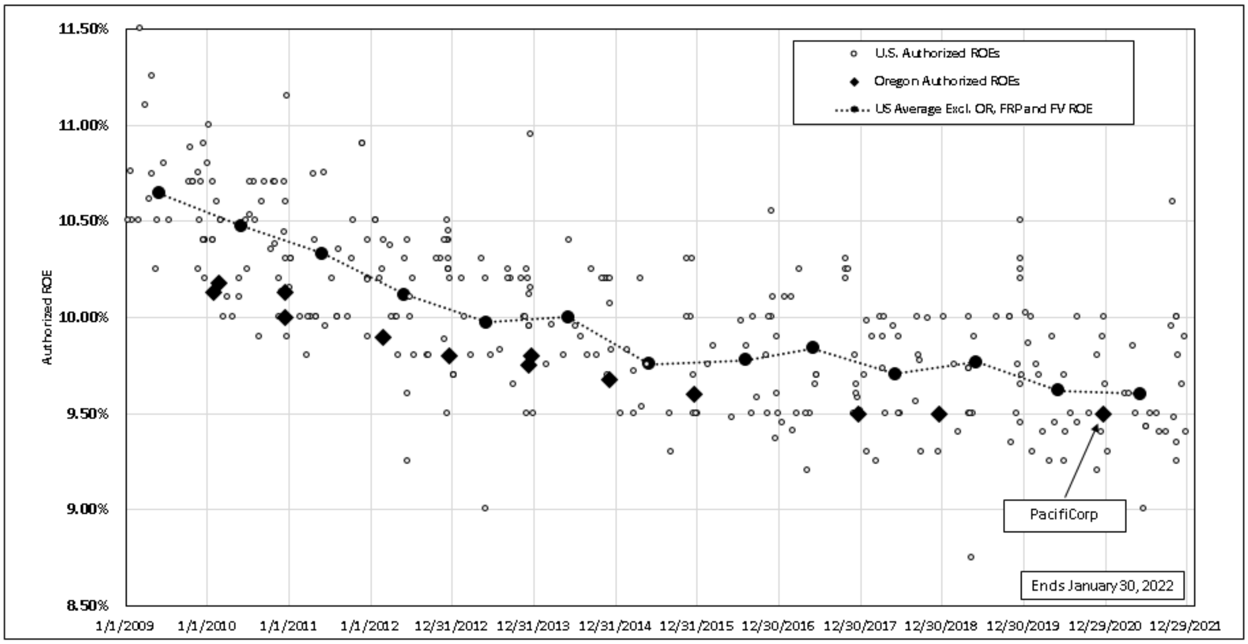
4. Volumetric Risk/Decoupling: PacifiCorp does not have protection against volumetric risk in Oregon. In contrast, approximately 49 percent of the operating companies held by the proxy group have some form of protection against volumetric risk through either a partial or full revenue decoupling mechanism that mitigates the effect of fluctuations in volume on revenues.

5. Capital Cost Recovery: PacifiCorp is authorized to separately file to recover capital costs to construct or otherwise acquire renewable generation facilities and the associated transmission. However, utilities in Oregon are prohibited by law from the inclusion of construction work in progress in rate base, and deferred accounting is not available for recovery of capital expenditures. By comparison, approximately 52 percent of the operating companies held by the proxy group also have some form of capital cost recovery mechanism in place that allows for recovery of capital costs between rate cases.

Q. How do recent returns in Oregon compare to the authorized returns in other jurisdictions?

A. As noted in RRA's evaluation above, the authorized ROEs for electric and natural gas utilities in Oregon, while largely the result of settlement agreements approved by the Commission, have been below the prevailing industry average for electric and natural gas utilities across the U.S. Figure 13 below shows the authorized returns for vertically integrated electric utilities in other jurisdictions since January 2009, and the returns authorized in Oregon for electric companies. As shown in Figure 13, the authorized returns for electric utilities in Oregon have been at the low end of the range of authorized ROEs in other state jurisdictions for 2015 through 2021.

Figure 13: Comparison of Oregon and U.S. Authorized Electric Returns[62]



Q. Is there any reason that the Commission should be concerned about authorizing equity returns that are at the low end of the range established by other state regulatory jurisdictions?

A. Yes. Credit rating agencies take the authorized ROE into consideration in the overall risk analysis of a company. Therefore, to the extent that the returns in a jurisdiction are lower than the returns that have been authorized more broadly, credit rating agencies will consider this in the overall risk assessment of the regulatory jurisdiction in which the company operates. Moody's downgraded ALLETE, Inc. from A3 to Baa1 primarily based on the less than favorable outcome in Minnesota Power's last

[62] Source: Capital IQ. Data excludes states where ROE is established based on a formula (Illinois and Vermont) and Arizona which relies on a fair value ROE.

fully litigated rate case in Minnesota which included what Moody's noted was a below average authorized ROE of 9.25 percent.[63] In addition, FitchRatings downgraded CenterPoint Energy Houston Electric's Long-Term Issuer Default rating from A- to BBB+ and revised the rating outlook from Stable to Negative following an unfavorable outcome in a recent rate case in Texas.[64] Finally, FitchRatings recently downgraded and maintained a negative outlook for Arizona Public Service Company (APS) and its parent, Pinnacle West Capital Corporation, following the hearings conducted by the Arizona Corporation Commission (ACC) in October 2021 regarding APS' current rate case proceeding.[65] While the ACC had not issued a final order in APS' rate case at the time, FitchRatings noted that the developments at the hearing in October indicate a likely credit negative outcome that will negatively affect the financial metrics of both APS and Pinnacle West Capital Corporation. It is also important to note that Moody's recently placed both APS and Pinnacle West Capital Corporation on review for downgrade following the ACC hearing in October.[66]

PacifiCorp must compete for capital with other utilities and businesses. Placing PacifiCorp at the lower end of authorized ROEs outside Oregon over the longer term could negatively impact its access to capital.

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[63] MOODY'S INVESTOR SERVICE, Credit Opinion: ALLETE, Inc. Update following downgrade at 3 (Apr. 3, 2019).
[64] FITCHRATINGS, Fitch Downgrades CenterPoint Energy Houston Electric to BBB+; Affirms CNP; Outlooks Negative (Feb. 19, 2020).
[65] FITCHRATINGS, Fitch Downgrades Pinnacle West Capital & Arizona Public Service to 'BBB+'; Outlooks Remain Negative (Oct. 12, 2021).
[66] MOODY'S INVESTORS SERVICE, Rating Actions: Moody's places Pinnacle West and Arizona Public Service ratings on review for downgrade (Oct. 12, 2021).

Q. How should the Commission use the information regarding authorized ROEs in other jurisdictions in determining the ROE for PacifiCorp?

A. As discussed above, the companies in the proxy group operate in multiple jurisdictions across the U.S. Since PacifiCorp must compete directly for capital with investments of similar risk, it is appropriate to review the authorized ROEs in other jurisdictions. The comparison is important because investors are considering the authorized returns across the U.S. and are likely to invest equity in those utilities with the highest returns. Furthermore, investors are also likely to consider business and financial risks for a company like PacifiCorp which faces increased risk as a result of the Company's capital expenditure plan and limited cost recovery mechanisms. Therefore, authorizing an ROE for PacifiCorp that is equivalent to the average authorized ROE for other vertically integrated electric utilities is not sufficient to compensate investors for the added risk of PacifiCorp. As such, it is important that the Commission consider, as I have in my recommendation, the additional risk of PacifiCorp and place the authorized ROE for PacifiCorp towards the high end of authorized ROEs for other vertically integrated electric utilities.

Q. What are your conclusions regarding the perceived risks related to the Oregon regulatory environment?

A. As discussed throughout this section of my testimony, both Moody's and S&P have identified the supportiveness of the regulatory environment as an important consideration in developing their overall credit ratings for regulated utilities. Considering the regulatory adjustment mechanisms, many of the companies in the proxy group have more timely cost recovery through fuel cost recovery mechanisms, fully forecasted test years, year-end rate base in all cases, capital cost recovery trackers, and revenue stabilization mechanisms than PacifiCorp has in Oregon. Additionally, authorized ROEs in Oregon have been below the average authorized ROEs for electric and gas utilities across the U.S. For these reasons, I conclude that the authorized ROE for PacifiCorp should be higher than the proxy group mean.

C. Generation Ownership

Q. How does the business risk of vertically integrated electric utilities compare to the business risk of other regulated utilities?

A. According to Moody's, generation ownership causes vertically integrated electric utilities to have higher business risk than either electric transmission and distribution companies, or natural gas distribution or transportation companies.[67] As a result of this higher business risk, integrated electric utilities typically require a higher ROE or percentage of equity in the capital structure than other electric or gas utilities.

Q. Are there other risk factors specific to vertically integrated electric utilities that the credit rating agencies consider when determining the credit rating of a company that owns generation?

A. Yes. As discussed above, Moody's establishes credit ratings based on four key factors: (1) regulatory framework; (2) the ability to recover costs and earn returns; (3) diversification; and (4) financial strength, liquidity and key financial metrics. The third factor diversification, which Moody's assigns a 10.00 percent weighting in the overall assessments of a company's business risk, considers the fuel source diversity

[67] MOODY'S INVESTORS SERVICE, *Rating Methodology: Regulated Electric and Gas Utilities* at 21-22 (Jun. 23, 2017).

of a utility with generation. Moody's notes:

> For utilities with electric generation, fuel source diversity can mitigate the impact (to the utility and to its rate-payers) of changes in commodity prices, hydrology and water flow, and environmental or other regulations affecting plant operations and economics. We have observed that utilities' regulatory environments are most likely to become unfavorable during periods of rapid rate increases (which are more important than absolute rate levels) and that fuel diversity leads to more stable rates over time.
>
> For that reason, fuel diversity can be important even if fuel and purchased power expenses are an automatic pass-through to the utility's ratepayers. Changes in environmental, safety and other regulations have caused vulnerabilities for certain technologies and fuel sources during the past five years. These vulnerabilities have varied widely in different countries and have changed over time.[68]

Q. Have you conducted an analysis to compare the fuel sources for the generation portfolio of PacifiCorp to the companies in your proxy group?

A. Yes, I have. Specifically, I calculated for PacifiCorp, and each company in the proxy group, the percentage of regulated owned generation capacity that was derived from one of the following fuel sources: oil/natural gas, coal, nuclear, hydro, and other. As shown in Figure 14, approximately 57.83 percent of PacifiCorp's regulated, owned generation came from coal-fired power plants with approximately 82.24 percent coming from either oil, natural gas, or coal-fired power plants. Therefore, PacifiCorp is more reliant on a limited number of fuel sources for its regulated generation and overall slightly less diversified than the companies in the proxy group.

[68] *Id.* at 16.

Figure 14: Regulated Owned Generation Capacity - Fuel Mix for PacifiCorp and Proxy Group[69]

Company	Ticker	Oil & Natural Gas	Coal	Nuclear	Hydro	Other	Total Regulated Generation Mix
ALLETE, Inc.	ALE	5.37%	51.59%	0.00%	7.54%	35.49%	100.00%
Alliant Energy Corporation	LNT	49.67%	27.56%	0.00%	0.70%	22.08%	100.00%
Ameren Corporation	AEE	30.96%	49.46%	11.03%	7.28%	1.27%	100.00%
American Electric Power Company, Inc.	AEP	35.18%	50.18%	9.78%	3.71%	1.15%	100.00%
Avista Corporation	AVA	33.44%	10.38%	0.00%	53.80%	2.37%	100.00%
CMS Energy Corporation	CMS	49.02%	21.78%	0.00%	19.04%	10.17%	100.00%
Duke Energy Corporation	DUK	46.29%	28.50%	17.00%	6.44%	1.77%	100.00%
Entergy Corporation	ETR	72.79%	11.17%	15.66%	0.29%	0.10%	100.00%
Evergy, Inc.	EVRG	34.48%	50.43%	10.06%	0.05%	4.99%	100.00%
IDACORP, Inc.	IDA	22.37%	22.73%	0.00%	54.90%	0.00%	100.00%
NextEra Energy, Inc.	NEE	76.09%	4.10%	10.59%	0.00%	9.23%	100.00%
NorthWestern Corporation	NWE	24.28%	32.39%	0.00%	33.60%	9.73%	100.00%
Otter Tail Corporation	OTTR	34.77%	37.92%	0.00%	0.39%	26.92%	100.00%
PacifiCorp	***PacifiCorp***	**24.41%**	**57.83%**	**0.00%**	**17.76%**		**100.00%**
Portland General Electric Company	POR	55.38%	8.36%	0.00%	13.03%	23.24%	100.00%
Southern Company	SO	48.84%	29.41%	11.55%	9.05%	1.15%	100.00%
Xcel Energy Inc.	XEL	40.74%	29.61%	7.96%	2.50%	19.19%	100.00%

Q. Is PacifiCorp's generation portfolio currently in a state of transition?

A. Yes. As further discussed in the testimony of Ms. Joelle R. Steward, the Company is responding to changing market conditions and, as indicated by the 2019 and 2021 Integrated Resource Plans (IRPs), is taking near term actions to retire certain coal units, invest in new renewable generation, and invest in associated transmission.

Q. What are your conclusions regarding the perceived risks related to the fuel mix of PacifiCorp's generation portfolio?

A. PacifiCorp's fossil-fuel generation is subject to increased environmental regulations aimed at cutting power plant emissions. The environmental regulations pose additional business risk as sizable future capital expenditures may be required to comply with regulations. Furthermore, the Company recently outlined plans for reshaping its generation portfolio. While the Company intends to improve fuel

[69] PacifiCorp's generation includes approximately 3,010 megawatts (MW) of wind generation, or approximately 12.25 percent of the portfolio. This generation is included in the combined percentage for "Hydro and Other" for comparison purposes with the proxy group data.

diversity over the long-run, the plans will require continued access to capital markets to finance the new investments. The Company's existing generation portfolio and proposed transmission and generation investment plans increase the overall risk profile as compared with the proxy group.

Q. Based on these analyses, what is your conclusion regarding the level of regulatory risk for the Company's operations relative to that of the proxy group companies?

A. As discussed, the ratemaking conventions used to develop the Company's rates and the mechanism used for the recovery of its costs are generally consistent with those relied upon by the majority of the utility operating subsidiaries of the proxy group companies.

D. Impact of Climate Change Initiatives

Q. Has Oregon enacted legislation that increases the Company's business risk going forward?

A. Yes. In 2021 Oregon enacted House Bill 2021 which requires that retail electricity providers reduce greenhouse gas (GHG) emissions associated with electricity sold to Oregon consumers by 80 percent below baseline emission levels by 2030, 90 percent reductions below baseline emissions levels by 2035, and 100 percent below baseline emissions levels by 2040.[70]

Q. Has PacifiCorp established a plan with respect to the reduction of GHG emissions?

A. Yes. Over time, through the 2017, 2019 and 2021 IRPs, PacifiCorp has outlined its

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[70] S&P Capital IQ, Commission Review accessed January 19, 2022.

plans to substantially increase renewable energy capacity and to upgrade the transmission network connecting supply with demand. The Company's 2021 IRP identifies critical investments in transmission, renewable energy, storage, demand response and advanced nuclear resources to meet its environmental goals. Over the period from 2021 through 2040, the Company plans to reduce demand by 4,290 MW through energy efficiency programs, increase solar resources by 5,628 MW, increase wind resources by 3,628 MW and add 6,181 MW of storage resources. Further, the Company plans 2,448 MW of direct load control programs and 500-1500 MW of advanced nuclear technology.[71]

Q. Has the Company identified plans to retire coal-fired generation to meet GHG reduction requirements?

A. Yes. The Company recently completed a coal-to-gas peaking generation conversion of Naughton Unit 3 in Wyoming and retired the Cholla Unit 4 generator in Arizona. In addition, over the next four years, the Company plans to begin the retirement or divestiture of Colstrip Units 3 and 4 in Montana, and Naughton Units 1 and 2. Further, the Company plans a coal-to-gas peaking conversion for Jim Bridger Units 1 and 2 in Wyoming[72]

Q. How much conservation and demand response is planned over the near-term, when the rates set in this proceeding are likely to be in effect?

A. The Company is planning 603 MW of energy efficiency and 549 MW of demand response between 2021 and 2024.

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[71] PacifiCorp 2021 IRP at 2.
[72] *Id.* at 4.

Q. Have the credit rating agencies comments on PacifiCorp's capital spending plans?

A. Yes. S&P has noted that continued regulatory support will be important to sustain credit quality as the Company implements its ever increasing renewable and transmission plan. Further S&P noted that the Company's metrics have been impacted by negative cash flow impacts of federal tax reform and the associated loss of bonus depreciation as well as regulatory lag and other events. Further, S&P expects that heightened capital expenditures will maintain downward pressure on credit metrics and to be funded with a mixture of debt and retained cash flow that will continue to support credit quality.[73]

Q. What are your overall conclusions regarding the Company's business risks related to GHG emission reduction initiatives in Oregon?

A. The Company is embarking on plans to meet the GHG emissions requirements established in House Bill 2021 that include significant demand reduction, retirements of generating assets and capital investment plans that include renewable resources and transmission investment that continue to provide customers with safe and reliable service. In order to meet these objectives in a manner that is least cost and lowest risk, which benefits customers, it is necessary that the ROE and equity ratio that are authorized in this proceeding support the Company's core financial metrics. The Company's proposed ROE and equity ratio would provide that necessary support.

[73] MOODY'S INVESTORS SERVICE, *Credit Opinion, PacifiCorp Update to credit analysis* (Jun. 30, 2021).

IX. CAPITAL STRUCTURE

Q. Is the capital structure of the Company an important consideration in the determination of the appropriate ROE?

A. Yes. All else equal, a higher debt ratio increases the risk to investors. For debt holders, higher debt ratios result in a greater portion of the available cash flow being required to meet debt service, thereby increasing the risk associated with the payments on debt. The result of increased risk is a higher interest rate. The incremental risk of a higher debt ratio is more significant for common equity shareholders, who are the residual claimants on the cash flow of the Company. Therefore, the greater the debt service requirement, the less cash flow is available for common equity holders.

Q. What is PacifiCorp's proposed capital structure?

A. As discussed in the direct testimony of Company witness Ms. Nikki L. Kobliha, PacifiCorp is proposing a capital structure that is composed of 52.25 percent common equity, 0.01 percent preferred stock and 47.74 percent long-term debt.

Q. Have you analyzed the capital structures of the proxy group companies?

A. Yes. I calculated the percentages of common equity, long-term debt and short-term debt over the most recent two years for each of the utility operating subsidiaries of the proxy group companies. Because the cost of equity is established based on the return that is derived from the risk-comparable proxy group, it is reasonable to look to the proxy group average capital structure to benchmark the equity ratio for the Company. As shown in PAC/311, the equity ratios for the utility operating subsidiaries of the proxy group range from 46.85 percent to 61.11 percent, with a median of 52.71

percent in the most recent year. PacifiCorp's proposed equity ratio of 52.25 percent is within the range of equity ratios of the proxy group. Accordingly, I consider the proposed equity ratios to be reasonable.

Q. Is there a relationship between the equity ratio and the authorized ROE?

A. Yes. As noted by the Commission in the Company's last rate proceeding, there is a relationship between the equity ratio and the return on equity.[74] The equity ratio is the primary indicator of financial risk for a regulated utility such as PacifiCorp. To the extent the equity ratio is reduced, it is necessary to increase the authorized ROE to compensate investors for the greater financial risk associated with a lower equity ratio.

Q. Will the capital structure and ROE authorized in this proceeding affect the Company's access to capital at reasonable rates?

A. Yes. The level of earnings authorized by the Commission directly affects the Company's ability to fund its operations with internally generated funds. Both bond investors and rating agencies expect a significant portion of ongoing capital investments to be financed with internally generated funds. In addition, it is important to recognize that because a utility's investment horizon is very long, investors require the assurance of a sufficiently high return to satisfy the long-run financing requirements of the assets placed into service. Those assurances, which often are measured by the relationship between internally generated cash flows and debt (or interest expense), depend quite heavily on the capital structure. As a consequence, both the ROE and capital structure are very important to debt and

[74] Order No. 20-476 at 31(fn 135).

equity investors. Furthermore, considering the capital market conditions discussed in Section V, the authorized ROE and capital structure take on even greater significance.

X. CONCLUSIONS AND RECOMMENDATION

Q. What is your conclusion regarding a fair ROE for PacifiCorp?

A. As discussed throughout my testimony, the authorized ROE should be a forward-looking estimate; therefore, the analyses supporting my recommendation rely on forward-looking inputs and assumptions (*e.g.*, projected earnings growth rates in the DCF model, forecasted risk-free rate and market risk premium in the CAPM analyses) and take into consideration capital market conditions, including the expected increasing interest rate environment and the underperformance of utility stocks as the economy emerges from the pandemic. The authorized ROE should also consider the relative regulatory, business, and financial risks of PacifiCorp compared to the proxy group.

As discussed previously, the cost of equity ranges from 9.90 percent to 10.75 percent considering the results of all of the models presented in Figure 14. Within this range, taking into consideration current and projected capital market conditions, as well as the specific risk factors discussed for PacifiCorp, I conclude that the Company's requested ROE of 9.80 percent is conservative.

Figure 14: Summary of Results

Constant Growth- Median DCF			
	Median Low	Median	Median High
30-Day Average	8.57%	9.44%	10.34%
90-Day Average	8.62%	9.50%	10.37%
180-Day Average	8.63%	9.35%	10.28%
Constant Growth Median	8.61%	9.43%	10.33%
Multi-Stage DCF-Median Results			
30-Day Average	9.01%	9.45%	9.79%
90-Day Average	9.03%	9.50%	9.81%
180-Day Average	9.02%	9.48%	9.73%
Multi-Stage Median	9.02%	9.48%	9.78%
CAPM			
	Current 30-day Average Treasury Bond Yield	Near-Term Blue Chip Forecast Yield	Long-Term Blue Chip Forecast Yield
Value Line Beta	11.28%	11.36%	11.47%
Bloomberg Beta	10.56%	10.68%	10.85%
Long-Term Avg. Beta	9.72%	9.90%	10.14%
Risk Premium			
	Current 30-day Average Treasury Bond Yield	Near-Term Blue Chip Forecast Yield	Long-Term Blue Chip Forecast Yield
Risk Premium Results	9.47%	9.75%	10.13%

Q. What is your conclusion with respect to PacifiCorp's requested capital structure?

A. My conclusion is that PacifiCorp's requested capital structure consisting of 52.25 percent common equity, 47.74 percent long-term debt and 0.01 preferred equity is reasonable.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 399
Exhibit PAC/301
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Ann E. Bulkley

Resume and Testimony Listing of Ann E. Bulkley

March 2022

Brattle

Ann E. Bulkley

PRINCIPAL

Boston | 508.981.0866 | Ann.Bulkley@brattle.com

With more than 25 years of experience in the energy industry, Ms. Bulkley specializes in regulatory economics for the electric and natural gas sectors, including rate of return, cost of equity, and capital structure issues.

Ms. Bulkley has extensive state and federal regulatory experience, and she has provided expert testimony on the cost of capital in nearly 100 regulatory proceedings before 32 state regulatory commissions and the Federal Energy Regulatory Commission (FERC).

In addition to her regulatory experience, Ms. Bulkley has provided valuation and appraisal services for a variety of purposes, including the sale or acquisition of utility assets, regulated ratemaking, ad valorem tax disputes, and other litigation purposes. In addition, she has experience in the areas of contract and business unit valuation, strategic alliances, market restructuring, and regulatory and litigation support.

Ms. Bulkley is a Certified General Appraiser licensed in the Commonwealth of Massachusetts and the State of New Hampshire.

Prior to joining Brattle, Ms. Bulkley was a Senior Vice President at an economic consultancy and held senior positions at several other consulting firms.

AREAS OF EXPERTISE

- Regulatory Economics, Finance & Rates
- Regulatory Investigations & Enforcement
- Tax Controversy & Transfer Pricing
- Electricity Litigation & Regulatory Disputes
- M&A Litigation

Brattle

EDUCATION

- **Boston University**
  MA in Economics
- **Simmons College**
  BA in Economics and Finance

PROFESSIONAL EXPERIENCE

- **The Brattle Group (2022–Present)**
  Principal
- **Concentric Energy Advisors, Inc. (2002–2021)**
  Senior Vice President
  Vice President
  Assistant Vice President
  Project Manager
- **Navigant Consulting, Inc. (1997–2002)**
  Project Manager
- **Reed Consulting Group (1995-1997)**
  Consultant- Project Manager
- **Cahners Publishing Company (1995)**
  Economist

SELECTED CONSULTING EXPERIENCE & EXPERT TESTIMONY

REGULATORY ANALYSIS AND RATEMAKING

Have provided a range of advisory services relating to regulatory policy analysis and many aspects of utility ratemaking, with specific services including:

- Cost of capital and return on equity testimony, cost of service and rate design analysis and testimony, development of ratemaking strategies
- Development of merchant function exit strategies

- Analysis and program development to address residual energy supply and/or provider of last resort obligations
- Stranded costs assessment and recovery
  Performance-based ratemaking analysis and design
- Many aspects of traditional utility ratemaking (e.g., rate design, rate base valuation)

COST OF CAPITAL

Have provided expert testimony on the cost of capital and capital structure in nearly 100 regulatory proceedings before state and federal regulatory commissions in the United States.

RATEMAKING

Have assisted several clients with analysis to support investor-owned and municipal utility clients in the preparation of rate cases. Sample engagements include:

- Assisted several investor-owned and municipal clients on cost allocation and rate design issues including the development of expert testimony supporting recommended rate alternatives.
- Worked with Canadian regulatory staff to establish filing requirements for a rate review of a newly regulated electric utility. Along with analyzing and evaluating rate application, attended hearings and conducted investigation of rate application for regulatory staff. And prepared, supported, and defended recommendations for revenue requirements and rates for the company. Additionally, developed rates for gas utility for transportation program and ancillary services.

VALUATION

Have provided valuation services to utility clients, unregulated generators, and private equity clients for a variety of purposes, including ratemaking, fair value, ad valorem tax, litigation and damages, and acquisition. Appraisal practices are consistent with the national standards established by the Uniform Standards of Professional Appraisal Practice.

Representative projects/clients have included:

- Prepared appraisals of electric utility transmission and distribution assets for ad valorem tax purposes.
- Prepared appraisals of several hydroelectric generating facilities for ad valorem tax purposes.
- Conducted appraisals of fossil fuel generating facilities for ad valorem tax purposes.
- Conducted appraisals of generating assets for the purposes of unwinding sale-leaseback agreements.
- For a confidential utility client, prepared valuation of fossil and nuclear generation assets for financing purposes for regulated utility client.

- Prepared a valuation of a portfolio of generation assets for a large energy utility to be used for strategic planning purposes. Valuation approach included an income approach, a real options analysis, and a risk analysis.
- Assisted clients in the restructuring of NUG contracts through the valuation of the underlying assets. Performed analysis to determine the option value of a plant in a competitively priced electricity market following the settlement of the NUG contract.
- Prepared market valuations of several purchase power contracts for large electric utilities in the sale of purchase power contracts. Assignment included an assessment of the regional power market, analysis of the underlying purchase power contracts, and a traditional discounted cash flow valuation approach, as well as a risk analysis. Analyzed bids from potential acquirers using income and risk analysis approached. Prepared an assessment of the credit issues and value at risk for the selling utility.
- Prepared appraisal of a portfolio of generating facilities for a large electric utility to be used for financing purposes.
- Prepared fair value rate base analyses for Northern Indiana Public Service Company for several electric rate proceedings. Valuation approaches used in this project included income, cost, and comparable sales approaches.
- Prepared an appraisal of a fleet of fossil generating assets for a large electric utility to establish the value of assets transferred from utility property.
- Conducted due diligence on an electric transmission and distribution system as part of a buy-side due diligence team.
- Provided analytical support for and prepared appraisal reports of generation assets to be used in ad valorem tax disputes.
- Provided analytical support and prepared testimony regarding the valuation of electric distribution system assets in five communities in a condemnation proceeding.
- Prepared feasibility reports analyzing the expected net benefits resulting from municipal ownership of investor-owned utility operations.
- Prepared independent analyses of proposal for the proposed government condemnation of the investor-owned utilities in Maine and the formation of a public power district.
- Valued purchase power agreements in the transfer of assets to a deregulated electric market.

STRATEGIC AND FINANCIAL ADVISORY SERVICES

Have assisted several clients across North America with analytically-based strategic planning, due diligence, and financial advisory services.

Representative projects include:

- Preparation of feasibility studies for bond issuances for municipal and district steam clients.
- Assisted in the development of a generation strategy for an electric utility. Analyzed various NERC regions to identify potential market entry points. Evaluated potential competitors and alliance partners. Assisted in the development of gas and electric price forecasts. Developed a framework for the implementation of a risk management program.
- Assisted clients in identifying potential joint venture opportunities and alliance partners. Contacted interviewed and evaluated potential alliance candidates based on company-established criteria for several LDCs and marketing companies. Worked with several LDCs and unregulated marketing companies to establish alliances to enter into the retail energy market. Prepared testimony in support of several merger cases and participated in the regulatory process to obtain approval for these mergers.
- Assisted clients in several buy-side due diligence efforts, providing regulatory insight and developing valuation recommendations for acquisitions of both electric and gas properties.

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Arizona Corporation Commission				
Southwest Gas Corporation	12/21	Southwest Gas Corporation	Docket No. G-01551A-21-0368	Return on Equity
Arizona Public Service Company	10/19	Arizona Public Service Company	Docket No. E-01345A-19-0236	Return on Equity
Tucson Electric Power Company	04/19	Tucson Electric Power Company	Docket No. E-01933A-19-0028	Return on Equity
Tucson Electric Power Company	11/15	Tucson Electric Power Company	Docket No. E-01933A-15-0322	Return on Equity
UNS Electric	05/15	UNS Electric	Docket No. E-04204A-15-0142	Return on Equity
UNS Electric	12/12	UNS Electric	Docket No. E-04204A-12-0504	Return on Equity
Arkansas Public Service Commission				
Oklahoma Gas and Electric Co	10/21	Oklahoma Gas and Electric Co	Docket No. D-18-046-FR	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Arkansas Oklahoma Gas Corporation	10/13	Arkansas Oklahoma Gas Corporation	Docket No. 13-078-U	Return on Equity
California Public Utilities Commission				
San Jose Water Company	05/21	San Jose Water Company	A2105004	Return on Equity
Colorado Public Utilities Commission				
Public Service Company of Colorado	07/21	Public Service Company of Colorado	21AL-0317E	Return on Equity
Public Service Company of Colorado	02/20	Public Service Company of Colorado	20AL-0049G	Return on Equity
Public Service Company of Colorado	05/19	Public Service Company of Colorado	19AL-0268E	Return on Equity
Public Service Company of Colorado	01/19	Public Service Company of Colorado	19AL-0063ST	Return on Equity
Atmos Energy Corporation	05/15	Atmos Energy Corporation	Docket No. 15AL-0299G	Return on Equity
Atmos Energy Corporation	04/14	Atmos Energy Corporation	Docket No. 14AL-0300G	Return on Equity
Atmos Energy Corporation	05/13	Atmos Energy Corporation	Docket No. 13AL-0496G	Return on Equity
Connecticut Public Utilities Regulatory Authority				
United Illuminating	05/21	United Illuminating	Docket No. 17-12-03RE11	Return on Equity
Connecticut Water Company	01/21	Connecticut Water Company	Docket No. 20-12-30	Return on Equity
Connecticut Natural Gas Corporation	06/18	Connecticut Natural Gas Corporation	Docket No. 18-05-16	Return on Equity
Yankee Gas Services Co. d/b/a Eversource Energy	06/18	Yankee Gas Services Co. d/b/a Eversource Energy	Docket No. 18-05-10	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
The Southern Connecticut Gas Company	06/17	The Southern Connecticut Gas Company	Docket No. 17-05-42	Return on Equity
The United Illuminating Company	07/16	The United Illuminating Company	Docket No. 16-06-04	Return on Equity
Federal Energy Regulatory Commission				
Florida Gas Transmission	02/21	Florida Gas Transmission	Docket No. RP21-441	Return on Equity
TransCanyon	01/21	TransCanyon	Docket No. ER21-1065	Return on Equity
Duke Energy	12/20	Duke Energy	Docket No. EL21-9-000	Return on Equity
Wisconsin Electric Power Company	08/20	Wisconsin Electric Power Company	Docket No. EL20-57-000	Return on Equity
Panhandle Eastern Pipe Line Company, LP	10/19	Panhandle Eastern Pipe Line Company, LP	Docket Nos. RP19-78-000 RP19-78-001	Return on Equity
Panhandle Eastern Pipe Line Company, LP	08/19	Panhandle Eastern Pipe Line Company, LP	Docket Nos. RP19-1523	Return on Equity
Sea Robin Pipeline Company LLC	11/18	Sea Robin Pipeline Company LLC	Docket# RP19-352-000	Return on Equity
Tallgrass Interstate Gas Transmission	10/15	Tallgrass Interstate Gas Transmission	RP16-137	Return on Equity
Idaho Public Utilities Commission				
PacifiCorp d/b/a Rocky Mountain Power	05/21	PacifiCorp d/b/a Rocky Mountain Power	Case No. PAC-E-21-07	Return on Equity
Illinois Commerce Commission				
North Shore Gas Company	02/21	North Shore Gas Company	No. 20-0810	Return on Equity
Indiana Utility Regulatory Commission				

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Indiana Michigan Power Co.	07/21	Indiana Michigan Power Co.	IURC Cause No. 45576	Return on Equity
Indiana Gas Company Inc.	12/20	Indiana Gas Company Inc.	IURC Cause No. 45468	Return on Equity
Southern Indiana Gas and Electric Company	10/20	Southern Indiana Gas and Electric Company	IURC Cause No. 45447	Return on Equity
Indiana and Michigan American Water Company	09/18	Indiana and Michigan American Water Company	IURC Cause No. 45142	Return on Equity
Indianapolis Power and Light Company	12/17	Indianapolis Power and Light Company	Cause No. 45029	Fair Value
Northern Indiana Public Service Company	09/17	Northern Indiana Public Service Company	Cause No. 44988	Fair Value
Indianapolis Power and Light Company	12/16	Indianapolis Power and Light Company	Cause No.44893	Fair Value
Northern Indiana Public Service Company	10/15	Northern Indiana Public Service Company	Cause No. 44688	Fair Value
Indianapolis Power and Light Company	09/15	Indianapolis Power and Light Company	Cause No. 44576 Cause No. 44602	Fair Value
Kokomo Gas and Fuel Company	09/10	Kokomo Gas and Fuel Company	Cause No. 43942	Fair Value
Northern Indiana Fuel and Light Company, Inc.	09/10	Northern Indiana Fuel and Light Company, Inc.	Cause No. 43943	Fair Value
Iowa Department of Commerce Utilities Board				
Iowa-American Water Company	08/20	Iowa-American Water Company	Docket No. RPU-2020-0001	Return on Equity
Kansas Corporation Commission				

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Atmos Energy Corporation	08/15	Atmos Energy Corporation	Docket No. 16-ATMG-079-RTS	Return on Equity
Kentucky Public Service Commission				
Kentucky American Water Company	11/18	Kentucky American Water Company	Docket No. 2018-00358	Return on Equity
Maine Public Utilities Commission				
Central Maine Power	10/18	Central Maine Power	Docket No. 2018-194	Return on Equity
Maryland Public Service Commission				
Maryland American Water Company	06/18	Maryland American Water Company	Case No. 9487	Return on Equity
Massachusetts Appellate Tax Board				
Hopkinton LNG Corporation	03/20	Hopkinton LNG Corporation	Docket No.	Valuation of LNG Facility
FirstLight Hydro Generating Company	06/17	FirstLight Hydro Generating Company	Docket No. F-325471 Docket No. F-325472 Docket No. F-325473 Docket No. F-325474	Valuation of Electric Generation Assets
Massachusetts Department of Public Utilities				
National Grid USA	11/20	Boston Gas Company	DPU 20-120	Return on Equity
Berkshire Gas Company	05/18	Berkshire Gas Company	DPU 18-40	Return on Equity
Unitil Corporation	01/04	Fitchburg Gas and Electric	DTE 03-52	Integrated Resource Plan; Gas Demand Forecast
Michigan Public Service Commission				
Michigan Gas Utilities Corporation	03/21	Michigan Gas Utilities Corporation	Case No. U-20718	Return on Equity
Wisconsin Electric Power Company	12/11	Wisconsin Electric Power Company	Case No. U-16830	Return on Equity

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SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Michigan Tax Tribunal				
New Covert Generating Co., LLC.	03/18	The Township of New Covert Michigan	MTT Docket No. 000248TT and 16-001888-TT	Valuation of Electric Generation Assets
Covert Township	07/14	New Covert Generating Co., LLC.	Docket No. 399578	Valuation of Electric Generation Assets
Minnesota Public Utilities Commission				
CenterPoint Energy Resources	11/21	CenterPoint Energy Resources	D-G-008/GR-21-435	Return on Equity
Allete, Inc. d/b/a Minnesota Power	11/21	Allete, Inc. d/b/a Minnesota Power	D-E-015/GR-21-630	Return on Equity
Otter Tail Power Company	11/20	Otter Tail Power Company	E017/GR-20-719	Return on Equity
Allete, Inc. d/b/a Minnesota Power	11/19	Allete, Inc. d/b/a Minnesota Power	E015/GR-19-442	Return on Equity
CenterPoint Energy Resources Corporation d/b/a CenterPoint Energy Minnesota Gas	10/19	CenterPoint Energy Resources Corporation d/b/a CenterPoint Energy Minnesota Gas	G-008/GR-19-524	Return on Equity
Great Plains Natural Gas Co.	09/19	Great Plains Natural Gas Co.	Docket No. G004/GR-19-511	Return on Equity
Minnesota Energy Resources Corporation	10/17	Minnesota Energy Resources Corporation	Docket No. G011/GR-17-563	Return on Equity
Missouri Public Service Commission				
Evergy Missouri West	1/22	Evergy Missouri West	File No. ER-2022-0130	Return on Equity

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SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Evergy Missouri Metro	1/22	Evergy Missouri Metro	File No. ER-2022-0129	Return on Equity
Ameren Missouri	03/21	Ameren Missouri	Docket No. ER-2021-0240 Docket No. GR-2021-0241	Return on Equity
Missouri American Water Company	06/20	Missouri American Water Company	Case No. WR-2020-0344 Case No. SR-2020-0345	Return on Equity
Missouri American Water Company	06/17	Missouri American Water Company	Case No. WR-17-0285 Case No. SR-17-0286	Return on Equity
Montana Public Service Commission				
Montana-Dakota Utilities Co.	06/20	Montana-Dakota Utilities Co.	D2020.06.076	Return on Equity
Montana-Dakota Utilities Co.	09/18	Montana-Dakota Utilities Co.	D2018.9.60	Return on Equity
New Hampshire - Board of Tax and Land Appeals				
Public Service Company of New Hampshire d/b/a Eversource Energy	11/19 12/19	Public Service Company of New Hampshire d/b/a Eversource Energy	Master Docket No. 28873-14-15-16-17PT	Valuation of Utility Property and Generating Assets
New Hampshire Public Utilities Commission				
Public Service Company of New Hampshire	05/19	Public Service Company of New Hampshire	DE-19-057	Return on Equity
New Hampshire-Merrimack County Superior Court				

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Northern New England Telephone Operations, LLC d/b/a FairPoint Communications, NNE	04/18	Northern New England Telephone Operations, LLC d/b/a FairPoint Communications, NNE	220-2012-CV-1100	Valuation of Utility Property
New Hampshire-Rockingham Superior Court				
Eversource Energy	05/18	Public Service Commission of New Hampshire	218-2016-CV-00899 218-2017-CV-00917	Valuation of Utility Property
New Jersey Board of Public Utilities				
Public Service Electric and Gas Company	10/20	Public Service Electric and Gas Company	EO18101115	Return on Equity
New Jersey American Water Company, Inc.	12/19	New Jersey American Water Company, Inc.	WR19121516	Return on Equity
Public Service Electric and Gas Company	04/19	Public Service Electric and Gas Company	EO18060629 GO18060630	Return on Equity
Public Service Electric and Gas Company	02/18	Public Service Electric and Gas Company	GR17070776	Return on Equity
Public Service Electric and Gas Company	01/18	Public Service Electric and Gas Company	ER18010029 GR18010030	Return on Equity
New Mexico Public Regulation Commission				
Southwestern Public Service Company	07/19	Southwestern Public Service Company	19-00170-UT	Return on Equity
Southwestern Public Service Company	10/17	Southwestern Public Service Company	Case No. 17-00255-UT	Return on Equity
Southwestern Public Service Company	12/16	Southwestern Public Service Company	Case No. 16-00269-UT	Return on Equity
Southwestern Public Service Company	10/15	Southwestern Public Service Company	Case No. 15-00296-UT	Return on Equity
Southwestern Public Service Company	06/15	Southwestern Public Service Company	Case No. 15-00139-UT	Return on Equity

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SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
New York State Department of Public Service				
Corning Natural Gas Corporation	07/21	Corning Natural Gas Corporation	Case No. 21-G-0394	Return on Equity
Central Hudson Gas and Electric Corporation	08/20	Central Hudson Gas and Electric Corporation	Electric 20-E-0428 Gas 20-G-0429	Return on Equity
Niagara Mohawk Power Corporation	07/20	National Grid USA	Case No. 20-E-0380 20-G-0381	Return on Equity
Corning Natural Gas Corporation	02/20	Corning Natural Gas Corporation	Case No. 20-G-0101	Return on Equity
New York State Electric and Gas Company Rochester Gas and Electric	05/19	New York State Electric and Gas Company Rochester Gas and Electric	19-E-0378 19-G-0379 19-E-0380 19-G-0381	Return on Equity
Brooklyn Union Gas Company d/b/a National Grid NY KeySpan Gas East Corporation d/b/a National Grid	04/19	Brooklyn Union Gas Company d/b/a National Grid NY KeySpan Gas East Corporation d/b/a National Grid	19-G-0309 19-G-0310	Return on Equity
Central Hudson Gas and Electric Corporation	07/17	Central Hudson Gas and Electric Corporation	Electric 17-E-0459 Gas 17-G-0460	Return on Equity
Niagara Mohawk Power Corporation	04/17	National Grid USA	Case No. 17-E-0238 17-G-0239	Return on Equity
Corning Natural Gas Corporation	06/16	Corning Natural Gas Corporation	Case No. 16-G-0369	Return on Equity
National Fuel Gas Company	04/16	National Fuel Gas Company	Case No. 16-G-0257	Return on Equity
KeySpan Energy Delivery	01/16	KeySpan Energy Delivery	Case No. 15-G-0058 Case No. 15-G-0059	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
New York State Electric and Gas Company Rochester Gas and Electric	05/15	New York State Electric and Gas Company Rochester Gas and Electric	Case No. 15-E-0283 Case No. 15-G-0284 Case No. 15-E-0285 Case No. 15-G-0286	Return on Equity
North Dakota Public Service Commission				
Montana-Dakota Utilities Co.	08/20	Montana-Dakota Utilities Co.	C-PU-20-379	Return on Equity
Northern States Power Company	12/12	Northern States Power Company	C-PU-12-813	Return on Equity
Northern States Power Company	12/10	Northern States Power Company	C-PU-10-657	Return on Equity
Oklahoma Corporation Commission				
Arkansas Oklahoma Gas Corporation	01/13	Arkansas Oklahoma Gas Corporation	Cause No. PUD 201200236	Return on Equity
Oregon Public Service Commission				
PacifiCorp d/b/a Pacific Power & Light	02/20	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-374	Return on Equity
Pennsylvania Public Utility Commission				
American Water Works Company Inc.	04/20	Pennsylvania-American Water Company	Docket No. R-2020-3019369 (water) Docket No. R-2020-3019371 (wastewater)	Return on Equity
American Water Works Company Inc.	04/17	Pennsylvania-American Water Company	Docket No. R-2017-2595853	Return on Equity
South Dakota Public Utilities Commission				
Northern States Power Company	06/14	Northern States Power Company	Docket No. EL14-058	Return on Equity
Texas Public Utility Commission				

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Southwestern Public Service Commission	08/19	Southwestern Public Service Commission	Docket No. D-49831	Return on Equity
Southwestern Public Service Company	01/14	Southwestern Public Service Company	Docket No. 42004	Return on Equity
Utah Public Service Commission				
PacifiCorp d/b/a Rocky Mountain Power	05/20	PacifiCorp d/b/a Rocky Mountain Power	Docket No. 20-035-04	Return on Equity
Virginia State Corporation Commission				
Virginia American Water Company, Inc.	11/21	Virginia American Water Company, Inc.	Docket No. PUR-2021-00255	Return on Equity
Virginia American Water Company, Inc.	11/18	Virginia American Water Company, Inc.	Docket No. PUR-2018-00175	Return on Equity
Washington Utilities Transportation Commission				
Cascade Natural Gas Corporation	06/20	Cascade Natural Gas Corporation	Docket No. UG-200568	Return on Equity
PacifiCorp d/b/a Pacific Power & Light	12/19	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-191024	Return on Equity
Cascade Natural Gas Corporation	04/19	Cascade Natural Gas Corporation	Docket No. UG-190210	Return on Equity
West Virginia Public Service Commission				
West Virginia American Water Company	04/21	West Virginia American Water Company	Case No. 21-02369-W-42T	Return on Equity
West Virginia American Water Company	04/18	West Virginia American Water Company	Case No. 18-0573-W-42T Case No. 18-0576-S-42T	Return on Equity
Wisconsin Public Service Commission				
Wisconsin Electric Power Company and Wisconsin Gas LLC	03/19	Wisconsin Electric Power Company and Wisconsin Gas LLC	Docket No. 05-UR-109	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Wisconsin Public Service Corp.	03/19	Wisconsin Public Service Corp.	6690-UR-126	Return on Equity
Wyoming Public Service Commission				
PacifiCorp d/b/a Rocky Mountain Power	03/20	PacifiCorp d/b/a Rocky Mountain Power	Docket No. 20000-578-ER-20	Return on Equity
Montana-Dakota Utilities Co.	05/19	Montana-Dakota Utilities Co.	30013-351-GR-19	Return on Equity

CERTIFICATIONS/ACCREDITATIONS

Certified General Appraiser, licensed in the Commonwealth of Massachusetts and the State of New Hampshire

Docket No. UE 399
Exhibit PAC/302
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Ann E. Bulkley

Summary of Results

March 2022

SUMMARY OF ROE RESULTS AS OF DECEMBER 31, 2022

Constant Growth- Median DCF			
	Median Low	Median	Median High
30-Day Average	8.57%	9.44%	10.34%
90-Day Average	8.62%	9.50%	10.37%
180-Day Average	8.63%	9.35%	10.28%
Constant Growth Median	8.61%	9.43%	10.33%
Multi-Stage DCF-Median Results			
30-Day Average	9.01%	9.45%	9.79%
90-Day Average	9.03%	9.50%	9.81%
180-Day Average	9.02%	9.48%	9.73%
Multi-Stage Median	9.02%	9.48%	9.78%
CAPM			
	Current 30-day Average Treasury Bond Yield	Near-Term Blue Chip Forecast Yield	Long-Term Blue Chip Forecast Yield
Value Line Beta	11.28%	11.36%	11.47%
Bloomberg Beta	10.56%	10.68%	10.85%
Long-Term Avg. Beta	9.72%	9.90%	10.14%
Risk Premium			
	Current 30-day Average Treasury Bond Yield	Near-Term Blue Chip Forecast Yield	Long-Term Blue Chip Forecast Yield
Risk Premium Results	9.47%	9.75%	10.13%

Docket No. UE 399
Exhibit PAC/303
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Ann E. Bulkley

Proxy Group Selection

March 2022

PROXY GROUP SCREENING DATA AND RESULTS - FINAL PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
Company		Dividends	S&P Credit Rating Between BBB- and AAA	Covered by More Than 1 Analyst	Positive Growth Rates from at least two sources (Value Line, Yahoo! First Call, and Zacks)	Generation Assets Included in Rate Base	% Regulated Coal Generation Capacity > 5%	% Regulated Operating Income > 60%	% Regulated Electric Operating Income ≥ 60%	Announced Merger
ALLETE, Inc.	ALE	Yes	BBB+	Yes	Yes	Yes	49.92%	75.0%	97.4%	No
Alliant Energy Corporation	LNT	Yes	A-	Yes	Yes	Yes	32.27%	96.9%	93.9%	No
Ameren Corporation	AEE	Yes	BBB+	Yes	Yes	Yes	49.97%	100.0%	88.3%	No
American Electric Power Company, Inc.	AEP	Yes	A-	Yes	Yes	Yes	51.92%	95.6%	100.0%	No
Avista Corporation	AVA	Yes	BBB	Yes	Yes	Yes	10.41%	100.0%	100.0%	No
CMS Energy Corporation	CMS	Yes	BBB+	Yes	Yes	Yes	23.18%	93.8%	74.2%	No
Duke Energy Corporation	DUK	Yes	A-	Yes	Yes	Yes	27.95%	100.0%	93.1%	No
Entergy Corporation	ETR	Yes	BBB+	Yes	Yes	Yes	13.07%	100.0%	98.9%	No
Evergy, Inc.	EVRG	Yes	A-	Yes	Yes	Yes	50.00%	100.0%	100.0%	No
IDACORP, Inc.	IDA	Yes	BBB	Yes	Yes	Yes	26.43%	98.9%	100.0%	No
NextEra Energy, Inc.	NEE	Yes	A-	Yes	Yes	Yes	8.56%	70.0%	100.0%	No
NorthWestern Corporation	NWE	Yes	BBB	Yes	Yes	Yes	32.54%	99.9%	84.4%	No
Otter Tail Corporation	OTTR	Yes	BBB	Yes	Yes	Yes	66.95%	73.5%	100.0%	No
Portland General Electric Company	POR	Yes	BBB+	Yes	Yes	Yes	20.81%	100.0%	100.0%	No
Southern Company	SO	Yes	A-	Yes	Yes	Yes	32.58%	95.7%	81.3%	No
Xcel Energy Inc.	XEL	Yes	A-	Yes	Yes	Yes	32.85%	100.0%	87.5%	No

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional
[3] Source: Yahoo! Finance and Zacks
[4] Source: Yahoo! Finance, Value Line Investment Survey, and Zacks
[5] to [6] Source: SNL Financial
[7] to [8] Source: Form 10-Ks for 2018, 2019 & 2020
[9] SNL Financial News Releases

Docket No. UE 399
Exhibit PAC/304
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Ann E. Bulkley

Constant Growth Discounted Cash Flow Model

March 2022

30-DAY CONSTANT GROWTH DCF

Company		[1] Annualized Dividend	[2] Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Value Line Earnings Growth	[6] Yahoo! Finance Earnings Growth	[7] Zacks Earnings Growth	[8] Average Growth Rate	[9] Low ROE	[10] Mean ROE	[11] High ROE
ALLETE, Inc.	ALE	$2.52	$63.13	3.99%	4.10%	5.00%	5.67%	6.00%	5.56%	9.09%	9.66%	10.11%
Alliant Energy Corporation	LNT	$1.61	$58.59	2.75%	2.83%	5.50%	6.10%	6.10%	5.90%	8.32%	8.73%	8.93%
Ameren Corporation	AEE	$2.20	$86.40	2.55%	2.64%	6.50%	7.90%	7.50%	7.30%	9.13%	9.94%	10.55%
American Electric Power Company, Inc.	AEP	$3.12	$84.96	3.67%	3.78%	6.50%	5.50%	5.70%	5.90%	9.27%	9.68%	10.29%
Avista Corporation	AVA	$1.69	$40.41	4.18%	4.28%	3.00%	6.20%	5.10%	4.77%	7.24%	9.05%	10.51%
CMS Energy Corporation	CMS	$1.74	$62.53	2.78%	2.87%	6.00%	5.62%	7.00%	6.21%	8.48%	9.08%	9.88%
Duke Energy Corporation	DUK	$3.94	$101.53	3.88%	3.98%	7.00%	2.50%	5.30%	4.93%	6.43%	8.91%	11.02%
Entergy Corporation	ETR	$4.04	$107.27	3.77%	3.85%	3.00%	6.00%	n/a	4.50%	6.82%	8.35%	9.88%
Evergy, Inc.	EVRG	$2.29	$66.43	3.45%	3.56%	8.00%	5.12%	6.10%	6.41%	8.66%	9.96%	11.59%
IDACORP, Inc.	IDA	$3.00	$109.22	2.75%	2.81%	4.00%	4.40%	4.40%	4.27%	6.80%	7.07%	7.21%
NextEra Energy, Inc.	NEE	$1.54	$89.80	1.71%	1.80%	10.50%	9.95%	8.90%	9.78%	10.69%	11.58%	12.30%
NorthWestern Corporation	NWE	$2.48	$55.96	4.43%	4.52%	3.00%	4.50%	4.10%	3.87%	7.50%	8.38%	9.03%
Otter Tail Corporation	OTTR	$1.56	$68.13	2.29%	2.37%	8.00%	9.00%	4.70%	7.23%	7.04%	9.61%	11.39%
Portland General Electric Company	POR	$1.72	$51.06	3.37%	3.50%	7.00%	7.15%	8.60%	7.58%	10.49%	11.08%	12.11%
Southern Company	SO	$2.64	$64.96	4.06%	4.18%	6.00%	6.20%	4.90%	5.70%	9.06%	9.88%	10.39%
Xcel Energy Inc.	XEL	$1.83	$66.39	2.76%	2.85%	6.00%	6.90%	6.40%	6.43%	8.84%	9.28%	9.75%
Median				3.41%	3.53%	6.00%	6.05%	6.00%	5.90%	8.57%	9.44%	10.34%

[1] Source: Bloomberg Professional, as of December 31, 2020
[2] Source: Bloomberg Professional, equals 30-day average as of December 31, 2021
[3] Equals [1] / [2]
[4] Source: Bloomberg Professional
[4] Source: Value Line
[5] Source: Value Line
[5] Source: Value Line
[5] Source: Value Line
[6] Source: Yahoo! Finance
[7] Source: Zacks
[7] Source: SNL Financial
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7])

90-DAY CONSTANT GROWTH DCF -- OR PROXY GROUP

Company		[1] Annualized Dividend	[2] Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Value Line Earnings Growth	[6] Yahoo! Finance Earnings Growth	[7] Zacks Earnings Growth	[8] Average Growth Rate	[9] Low ROE	[10] Mean ROE	[11] High ROE
ALLETE, Inc.	ALE	$2.52	$62.93	4.00%	4.12%	5.00%	5.67%	6.00%	5.56%	9.10%	9.67%	10.12%
Alliant Energy Corporation	LNT	$1.61	$57.81	2.78%	2.87%	5.50%	6.10%	6.10%	5.90%	8.36%	8.77%	8.97%
Ameren Corporation	AEE	$2.20	$85.14	2.58%	2.68%	6.50%	7.90%	7.50%	7.30%	9.17%	9.98%	10.59%
American Electric Power Company, Inc.	AEP	$3.12	$84.99	3.67%	3.78%	6.50%	5.50%	5.70%	5.90%	9.27%	9.68%	10.29%
Avista Corporation	AVA	$1.69	$40.38	4.19%	4.29%	3.00%	6.20%	5.10%	4.77%	7.25%	9.05%	10.52%
CMS Energy Corporation	CMS	$1.74	$61.76	2.82%	2.90%	6.00%	5.62%	7.00%	6.21%	8.52%	9.11%	9.92%
Duke Energy Corporation	DUK	$3.94	$101.55	3.88%	3.98%	7.00%	2.50%	5.30%	4.93%	6.43%	8.91%	11.02%
Entergy Corporation	ETR	$4.04	$106.25	3.80%	3.89%	3.00%	6.00%	n/a	4.50%	6.86%	8.39%	9.92%
Evergy, Inc.	EVRG	$2.29	$65.27	3.51%	3.62%	8.00%	5.12%	6.10%	6.41%	8.72%	10.03%	11.65%
IDACORP, Inc.	IDA	$3.00	$106.01	2.83%	2.89%	4.00%	4.40%	4.40%	4.27%	6.89%	7.16%	7.29%
NextEra Energy, Inc.	NEE	$1.54	$85.45	1.80%	1.89%	10.50%	9.95%	8.90%	9.78%	10.78%	11.67%	12.40%
NorthWestern Corporation	NWE	$2.48	$58.26	4.26%	4.34%	3.00%	4.50%	4.10%	3.87%	7.32%	8.21%	8.85%
Otter Tail Corporation	OTTR	$1.56	$62.00	2.52%	2.61%	8.00%	9.00%	4.70%	7.23%	7.28%	9.84%	11.63%
Portland General Electric Company	POR	$1.72	$49.88	3.45%	3.58%	7.00%	7.15%	8.60%	7.58%	10.57%	11.16%	12.20%
Southern Company	SO	$2.64	$64.12	4.12%	4.23%	6.00%	6.20%	4.90%	5.70%	9.12%	9.93%	10.44%
Xcel Energy Inc.	XEL	$1.83	$65.47	2.80%	2.89%	6.00%	6.90%	6.40%	6.43%	8.88%	9.32%	9.79%
Median				3.48%	3.60%	6.00%	6.05%	6.00%	5.90%	8.62%	9.50%	10.37%

[1] Source: Bloomberg Professional, as of December 31, 2020
[2] Source: Bloomberg Professional, equals 90-day average as of December 31, 2021
[3] Equals [1] / [2]
[4] Source: Bloomberg Professional
[4] Source: Value Line
[5] Source: Value Line
[5] Source: Value Line
[5] Source: Value Line
[6] Source: Yahoo! Finance
[7] Source: Zacks
[7] Source: SNL Financial
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7])

180-DAY CONSTANT GROWTH DCF -- OR PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company		Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Earnings Growth	Yahoo! Finance Earnings Growth	Zacks Earnings Growth	Average Growth Rate	Low ROE	Mean ROE	High ROE
ALLETE, Inc.	ALE	$2.52	$66.46	3.79%	3.90%	5.00%	5.67%	6.00%	5.56%	8.89%	9.45%	9.91%
Alliant Energy Corporation	LNT	$1.61	$57.87	2.78%	2.86%	5.50%	6.10%	6.10%	5.90%	8.36%	8.76%	8.97%
Ameren Corporation	AEE	$2.20	$84.84	2.59%	2.69%	6.50%	7.90%	7.50%	7.30%	9.18%	9.99%	10.60%
American Electric Power Company, Inc.	AEP	$3.12	$85.87	3.63%	3.74%	6.50%	5.50%	5.70%	5.90%	9.23%	9.64%	10.25%
Avista Corporation	AVA	$1.69	$42.34	3.99%	4.09%	3.00%	6.20%	5.10%	4.77%	7.05%	8.85%	10.32%
CMS Energy Corporation	CMS	$1.74	$62.01	2.81%	2.89%	6.00%	5.62%	7.00%	6.21%	8.50%	9.10%	9.90%
Duke Energy Corporation	DUK	$3.94	$102.02	3.86%	3.96%	7.00%	2.50%	5.30%	4.93%	6.41%	8.89%	11.00%
Entergy Corporation	ETR	$4.04	$106.04	3.81%	3.90%	3.00%	6.00%	n/a	4.50%	6.87%	8.40%	9.92%
Evergy, Inc.	EVRG	$2.29	$64.59	3.55%	3.66%	8.00%	5.12%	6.10%	6.41%	8.76%	10.07%	11.69%
IDACORP, Inc.	IDA	$3.00	$103.97	2.89%	2.95%	4.00%	4.40%	4.40%	4.27%	6.94%	7.21%	7.35%
NextEra Energy, Inc.	NEE	$1.54	$80.89	1.90%	2.00%	10.50%	9.95%	8.90%	9.78%	10.89%	11.78%	12.50%
NorthWestern Corporation	NWE	$2.48	$60.99	4.07%	4.14%	3.00%	4.50%	4.10%	3.87%	7.13%	8.01%	8.66%
Otter Tail Corporation	OTTR	$1.56	$55.71	2.80%	2.90%	8.00%	9.00%	4.70%	7.23%	7.57%	10.13%	11.93%
Portland General Electric Company	POR	$1.72	$49.44	3.48%	3.61%	7.00%	7.15%	8.60%	7.58%	10.60%	11.19%	12.23%
Southern Company	SO	$2.64	$64.07	4.12%	4.24%	6.00%	6.20%	4.90%	5.70%	9.12%	9.94%	10.45%
Xcel Energy Inc.	XEL	$1.83	$67.39	2.72%	2.80%	6.00%	6.90%	6.40%	6.43%	8.80%	9.24%	9.71%
Median				3.51%	3.63%	6.00%	6.05%	6.00%	5.90%	8.63%	9.35%	10.28%

[1] Source: Bloomberg Professional, as of December 31, 2020
[2] Source: Bloomberg Professional, equals 180-day average as of December 31, 2021
[3] Equals [1] / [2]
[4] Source: Bloomberg Professional
[4] Source: Value Line
[5] Source: Value Line
[5] Source: Value Line
[5] Source: Value Line
[6] Source: Yahoo! Finance
[7] Source: Zacks
[7] Source: SNL Financial
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7])

Docket No. UE 399
Exhibit PAC/305
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Ann E. Bulkley

Multi-Stage Discounted Cash Flow Model

March 2022

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

		1	2	3	4	5	6	7	8	9	10
Company		Annualized Dividend	Stock Price	First Stage Growth Rate (low)	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth Rate	ROE
ALLETE, Inc.	ALE	$2.52	$63.13	5.00%	5.08%	5.16%	5.24%	5.32%	5.41%	5.49%	9.76%
Alliant Energy Corporation	LNT	$1.61	$58.59	5.50%	5.50%	5.50%	5.49%	5.49%	5.49%	5.49%	8.49%
Ameren Corporation	AEE	$2.20	$86.40	6.50%	6.33%	6.16%	5.99%	5.82%	5.66%	5.49%	8.46%
American Electric Power Company, Inc.	AEP	$3.12	$84.96	5.50%	5.50%	5.50%	5.49%	5.49%	5.49%	5.49%	9.54%
Avista Corporation	AVA	$1.69	$40.41	3.00%	3.41%	3.83%	4.24%	4.66%	5.07%	5.49%	9.42%
CMS Energy Corporation	CMS	$1.74	$62.53	5.62%	5.60%	5.58%	5.55%	5.53%	5.51%	5.49%	8.56%
Duke Energy Corporation	DUK	$3.94	$101.53	2.50%	3.00%	3.50%	3.99%	4.49%	4.99%	5.49%	9.00%
Entergy Corporation	ETR	$4.04	$107.27	3.00%	3.41%	3.83%	4.24%	4.66%	5.07%	5.49%	9.01%
Evergy, Inc.	EVRG	$2.29	$66.43	5.12%	5.18%	5.24%	5.30%	5.36%	5.43%	5.49%	9.19%
IDACORP, Inc.	IDA	$3.00	$109.22	4.00%	4.25%	4.50%	4.74%	4.99%	5.24%	5.49%	8.20%
NextEra Energy, Inc.	NEE	$1.54	$89.80	8.90%	8.33%	7.76%	7.19%	6.62%	6.06%	5.49%	7.80%
NorthWestern Corporation	NWE	$2.48	$55.96	3.00%	3.41%	3.83%	4.24%	4.66%	5.07%	5.49%	9.67%
Otter Tail Corporation	OTTR	$1.56	$68.13	4.70%	4.83%	4.96%	5.09%	5.22%	5.36%	5.49%	7.83%
Portland General Electric Company	POR	$1.72	$51.06	7.00%	6.75%	6.50%	6.24%	5.99%	5.74%	5.49%	9.57%
Southern Company	SO	$2.64	$64.96	4.90%	5.00%	5.10%	5.19%	5.29%	5.39%	5.49%	9.81%
Xcel Energy Inc.	XEL	$1.83	$66.39	6.00%	5.91%	5.83%	5.74%	5.66%	5.57%	5.49%	8.60%
Median					5.13%	5.20%	5.27%	5.34%	5.42%	5.49%	9.01%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 30-trading day average as of December 31, 2021
[3] Source: Exhibit PAC 304
[4] Equals [3] + ([9] − [3]) / 6
[5] Equals [4] + ([9] − [3]) / 6
[6] Equals [5] + ([9] − [3]) / 6
[7] Equals [6] + ([9] − [3]) / 6
[8] Equals [7] + ([9] − [3]) / 6
[9] Source: Exhibit PAC 306
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

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

		1	2	3	4	5	6	7	8	9	10
Company		Annualized Dividend	Stock Price	First Stage Growth Rate (low)	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth Rate	ROE
ALLETE, Inc.	ALE	$2.52	$62.93	5.00%	5.08%	5.16%	5.24%	5.32%	5.41%	5.49%	9.77%
Alliant Energy Corporation	LNT	$1.61	$57.81	5.50%	5.50%	5.50%	5.49%	5.49%	5.49%	5.49%	8.53%
Ameren Corporation	AEE	$2.20	$85.14	6.50%	6.33%	6.16%	5.99%	5.82%	5.66%	5.49%	8.50%
American Electric Power Company, Inc.	AEP	$3.12	$84.99	5.50%	5.50%	5.50%	5.49%	5.49%	5.49%	5.49%	9.53%
Avista Corporation	AVA	$1.69	$40.38	3.00%	3.41%	3.83%	4.24%	4.66%	5.07%	5.49%	9.42%
CMS Energy Corporation	CMS	$1.74	$61.76	5.62%	5.60%	5.58%	5.55%	5.53%	5.51%	5.49%	8.59%
Duke Energy Corporation	DUK	$3.94	$101.55	2.50%	3.00%	3.50%	3.99%	4.49%	4.99%	5.49%	9.00%
Entergy Corporation	ETR	$4.04	$106.25	3.00%	3.41%	3.83%	4.24%	4.66%	5.07%	5.49%	9.05%
Evergy, Inc.	EVRG	$2.29	$65.27	5.12%	5.18%	5.24%	5.30%	5.36%	5.43%	5.49%	9.26%
IDACORP, Inc.	IDA	$3.00	$106.01	4.00%	4.25%	4.50%	4.74%	4.99%	5.24%	5.49%	8.28%
NextEra Energy, Inc.	NEE	$1.54	$85.45	8.90%	8.33%	7.76%	7.19%	6.62%	6.06%	5.49%	7.92%
NorthWestern Corporation	NWE	$2.48	$58.26	3.00%	3.41%	3.83%	4.24%	4.66%	5.07%	5.49%	9.49%
Otter Tail Corporation	OTTR	$1.56	$62.00	4.70%	4.83%	4.96%	5.09%	5.22%	5.36%	5.49%	8.08%
Portland General Electric Company	POR	$1.72	$49.88	7.00%	6.75%	6.50%	6.24%	5.99%	5.74%	5.49%	9.66%
Southern Company	SO	$2.64	$64.12	4.90%	5.00%	5.10%	5.19%	5.29%	5.39%	5.49%	9.87%
Xcel Energy Inc.	XEL	$1.83	$65.47	6.00%	5.91%	5.83%	5.74%	5.66%	5.57%	5.49%	8.65%
Median					5.13%	5.20%	5.27%	5.34%	5.42%	5.49%	9.03%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 90-trading day average as of December 31, 2021
[3] Source: Exhibit PAC 304
[4] Equals [3] + ([9] − [3]) / 6
[5] Equals [4] + ([9] − [3]) / 6
[6] Equals [5] + ([9] − [3]) / 6
[7] Equals [6] + ([9] − [3]) / 6
[8] Equals [7] + ([9] − [3]) / 6
[9] Source: Exhibit PAC 306
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

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

		1	2	3	4	5	6	7	8	9	10
Company		Annualized Dividend	Stock Price	First Stage Growth Rate (low)	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth Rate	ROE
ALLETE, Inc.	ALE	$2.52	$66.46	5.00%	5.08%	5.16%	5.24%	5.32%	5.41%	5.49%	9.54%
Alliant Energy Corporation	LNT	$1.61	$57.87	5.50%	5.50%	5.50%	5.49%	5.49%	5.49%	5.49%	8.53%
Ameren Corporation	AEE	$2.20	$84.84	6.50%	6.33%	6.16%	5.99%	5.82%	5.66%	5.49%	8.51%
American Electric Power Company, Inc.	AEP	$3.12	$85.87	5.50%	5.50%	5.50%	5.49%	5.49%	5.49%	5.49%	9.49%
Avista Corporation	AVA	$1.69	$42.34	3.00%	3.41%	3.83%	4.24%	4.66%	5.07%	5.49%	9.23%
CMS Energy Corporation	CMS	$1.74	$62.01	5.62%	5.60%	5.58%	5.55%	5.53%	5.51%	5.49%	8.58%
Duke Energy Corporation	DUK	$3.94	$102.02	2.50%	3.00%	3.50%	3.99%	4.49%	4.99%	5.49%	8.99%
Entergy Corporation	ETR	$4.04	$106.04	3.00%	3.41%	3.83%	4.24%	4.66%	5.07%	5.49%	9.06%
Evergy, Inc.	EVRG	$2.29	$64.59	5.12%	5.18%	5.24%	5.30%	5.36%	5.43%	5.49%	9.30%
IDACORP, Inc.	IDA	$3.00	$103.97	4.00%	4.25%	4.50%	4.74%	4.99%	5.24%	5.49%	8.34%
NextEra Energy, Inc.	NEE	$1.54	$80.89	8.90%	8.33%	7.76%	7.19%	6.62%	6.06%	5.49%	8.07%
NorthWestern Corporation	NWE	$2.48	$60.99	3.00%	3.41%	3.83%	4.24%	4.66%	5.07%	5.49%	9.31%
Otter Tail Corporation	OTTR	$1.56	$55.71	4.70%	4.83%	4.96%	5.09%	5.22%	5.36%	5.49%	8.39%
Portland General Electric Company	POR	$1.72	$49.44	7.00%	6.75%	6.50%	6.24%	5.99%	5.74%	5.49%	9.70%
Southern Company	SO	$2.64	$64.07	4.90%	5.00%	5.10%	5.19%	5.29%	5.39%	5.49%	9.87%
Xcel Energy Inc.	XEL	$1.83	$67.39	6.00%	5.91%	5.83%	5.74%	5.66%	5.57%	5.49%	8.56%
Median					5.13%	5.20%	5.27%	5.34%	5.42%	5.49%	9.02%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 180-trading day average as of December 31, 2021
[3] Source: Exhibit PAC 304
[4] Equals [3] + ([9] − [3]) / 6
[5] Equals [4] + ([9] − [3]) / 6
[6] Equals [5] + ([9] − [3]) / 6
[7] Equals [6] + ([9] − [3]) / 6
[8] Equals [7] + ([9] − [3]) / 6
[9] Source: Exhibit PAC 306
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

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

		1	2	3	4	5	6	7	8	9	10
Company		Annualized Dividend	Stock Price	First Stage Growth Rate (Mean)	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth Rate	ROE
ALLETE, Inc.	ALE	$2.52	$63.13	5.56%	5.54%	5.53%	5.52%	5.51%	5.50%	5.49%	9.91%
Alliant Energy Corporation	LNT	$1.61	$58.59	5.90%	5.83%	5.76%	5.69%	5.62%	5.56%	5.49%	8.57%
Ameren Corporation	AEE	$2.20	$86.40	7.30%	7.00%	6.70%	6.39%	6.09%	5.79%	5.49%	8.62%
American Electric Power Company, Inc.	AEP	$3.12	$84.96	5.90%	5.83%	5.76%	5.69%	5.62%	5.56%	5.49%	9.64%
Avista Corporation	AVA	$1.69	$40.41	4.77%	4.89%	5.01%	5.13%	5.25%	5.37%	5.49%	9.90%
CMS Energy Corporation	CMS	$1.74	$62.53	6.21%	6.09%	5.97%	5.85%	5.73%	5.61%	5.49%	8.68%
Duke Energy Corporation	DUK	$3.94	$101.53	4.93%	5.03%	5.12%	5.21%	5.30%	5.39%	5.49%	9.62%
Entergy Corporation	ETR	$4.04	$107.27	4.50%	4.66%	4.83%	4.99%	5.16%	5.32%	5.49%	9.38%
Evergy, Inc.	EVRG	$2.29	$66.43	6.41%	6.25%	6.10%	5.95%	5.79%	5.64%	5.49%	9.51%
IDACORP, Inc.	IDA	$3.00	$109.22	4.27%	4.47%	4.67%	4.88%	5.08%	5.28%	5.49%	8.25%
NextEra Energy, Inc.	NEE	$1.54	$89.80	9.78%	9.07%	8.35%	7.63%	6.92%	6.20%	5.49%	7.94%
NorthWestern Corporation	NWE	$2.48	$55.96	3.87%	4.14%	4.41%	4.68%	4.95%	5.22%	5.49%	9.91%
Otter Tail Corporation	OTTR	$1.56	$68.13	7.23%	6.94%	6.65%	6.36%	6.07%	5.78%	5.49%	8.28%
Portland General Electric Company	POR	$1.72	$51.06	7.58%	7.23%	6.88%	6.53%	6.19%	5.84%	5.49%	9.72%
Southern Company	SO	$2.64	$64.96	5.70%	5.66%	5.63%	5.59%	5.56%	5.52%	5.49%	10.04%
Xcel Energy Inc.	XEL	$1.83	$66.39	6.43%	6.28%	6.12%	5.96%	5.80%	5.64%	5.49%	8.69%
Median					5.83%	5.76%	5.69%	5.62%	5.56%	5.49%	9.45%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 30-trading day average as of December 31, 2021
[3] Source: Exhibit PAC 304
[4] Equals [3] + ([9] – [3]) / 6
[5] Equals [4] + ([9] – [3]) / 6
[6] Equals [5] + ([9] – [3]) / 6
[7] Equals [6] + ([9] – [3]) / 6
[8] Equals [7] + ([9] – [3]) / 6
[9] Source: Exhibit PAC 306
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

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

		1	2	3	4	5	6	7	8	9	10
Company		Annualized Dividend	Stock Price	First Stage Growth Rate (Mean)	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth Rate	ROE
ALLETE, Inc.	ALE	$2.52	$62.93	5.56%	5.54%	5.53%	5.52%	5.51%	5.50%	5.49%	9.93%
Alliant Energy Corporation	LNT	$1.61	$57.81	5.90%	5.83%	5.76%	5.69%	5.62%	5.56%	5.49%	8.62%
Ameren Corporation	AEE	$2.20	$85.14	7.30%	7.00%	6.70%	6.39%	6.09%	5.79%	5.49%	8.66%
American Electric Power Company, Inc.	AEP	$3.12	$84.99	5.90%	5.83%	5.76%	5.69%	5.62%	5.56%	5.49%	9.64%
Avista Corporation	AVA	$1.69	$40.38	4.77%	4.89%	5.01%	5.13%	5.25%	5.37%	5.49%	9.90%
CMS Energy Corporation	CMS	$1.74	$61.76	6.21%	6.09%	5.97%	5.85%	5.73%	5.61%	5.49%	8.72%
Duke Energy Corporation	DUK	$3.94	$101.55	4.93%	5.03%	5.12%	5.21%	5.30%	5.39%	5.49%	9.62%
Entergy Corporation	ETR	$4.04	$106.25	4.50%	4.66%	4.83%	4.99%	5.16%	5.32%	5.49%	9.42%
Evergy, Inc.	EVRG	$2.29	$65.27	6.41%	6.25%	6.10%	5.95%	5.79%	5.64%	5.49%	9.58%
IDACORP, Inc.	IDA	$3.00	$106.01	4.27%	4.47%	4.67%	4.88%	5.08%	5.28%	5.49%	8.34%
NextEra Energy, Inc.	NEE	$1.54	$85.45	9.78%	9.07%	8.35%	7.63%	6.92%	6.20%	5.49%	8.07%
NorthWestern Corporation	NWE	$2.48	$58.26	3.87%	4.14%	4.41%	4.68%	4.95%	5.22%	5.49%	9.73%
Otter Tail Corporation	OTTR	$1.56	$62.00	7.23%	6.94%	6.65%	6.36%	6.07%	5.78%	5.49%	8.56%
Portland General Electric Company	POR	$1.72	$49.88	7.58%	7.23%	6.88%	6.53%	6.19%	5.84%	5.49%	9.82%
Southern Company	SO	$2.64	$64.12	5.70%	5.66%	5.63%	5.59%	5.56%	5.52%	5.49%	10.10%
Xcel Energy Inc.	XEL	$1.83	$65.47	6.43%	6.28%	6.12%	5.96%	5.80%	5.64%	5.49%	8.74%
Median					5.83%	5.76%	5.69%	5.62%	5.56%	5.49%	9.50%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 90-trading day average as of December 31, 2021
[3] Source: Exhibit PAC 304
[4] Equals [3] + ([9] – [3]) / 6
[5] Equals [4] + ([9] – [3]) / 6
[6] Equals [5] + ([9] – [3]) / 6
[7] Equals [6] + ([9] – [3]) / 6
[8] Equals [7] + ([9] – [3]) / 6
[9] Source: Exhibit PAC 306
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

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

		1	2	3	4	5	6	7	8	9	10
Company		Annualized Dividend	Stock Price	First Stage Growth Rate (Mean)	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth Rate	ROE
ALLETE, Inc.	ALE	$2.52	$66.46	5.56%	5.54%	5.53%	5.52%	5.51%	5.50%	5.49%	9.69%
Alliant Energy Corporation	LNT	$1.61	$57.87	5.90%	5.83%	5.76%	5.69%	5.62%	5.56%	5.49%	8.61%
Ameren Corporation	AEE	$2.20	$84.84	7.30%	7.00%	6.70%	6.39%	6.09%	5.79%	5.49%	8.67%
American Electric Power Company, Inc.	AEP	$3.12	$85.87	5.90%	5.83%	5.76%	5.69%	5.62%	5.56%	5.49%	9.60%
Avista Corporation	AVA	$1.69	$42.34	4.77%	4.89%	5.01%	5.13%	5.25%	5.37%	5.49%	9.69%
CMS Energy Corporation	CMS	$1.74	$62.01	6.21%	6.09%	5.97%	5.85%	5.73%	5.61%	5.49%	8.70%
Duke Energy Corporation	DUK	$3.94	$102.02	4.93%	5.03%	5.12%	5.21%	5.30%	5.39%	5.49%	9.60%
Entergy Corporation	ETR	$4.04	$106.04	4.50%	4.66%	4.83%	4.99%	5.16%	5.32%	5.49%	9.43%
Evergy, Inc.	EVRG	$2.29	$64.59	6.41%	6.25%	6.10%	5.95%	5.79%	5.64%	5.49%	9.63%
IDACORP, Inc.	IDA	$3.00	$103.97	4.27%	4.47%	4.67%	4.88%	5.08%	5.28%	5.49%	8.40%
NextEra Energy, Inc.	NEE	$1.54	$80.89	9.78%	9.07%	8.35%	7.63%	6.92%	6.20%	5.49%	8.22%
NorthWestern Corporation	NWE	$2.48	$60.99	3.87%	4.14%	4.41%	4.68%	4.95%	5.22%	5.49%	9.53%
Otter Tail Corporation	OTTR	$1.56	$55.71	7.23%	6.94%	6.65%	6.36%	6.07%	5.78%	5.49%	8.92%
Portland General Electric Company	POR	$1.72	$49.44	7.58%	7.23%	6.88%	6.53%	6.19%	5.84%	5.49%	9.86%
Southern Company	SO	$2.64	$64.07	5.70%	5.66%	5.63%	5.59%	5.56%	5.52%	5.49%	10.10%
Xcel Energy Inc.	XEL	$1.83	$67.39	6.43%	6.28%	6.12%	5.96%	5.80%	5.64%	5.49%	8.65%
Median					5.83%	5.76%	5.69%	5.62%	5.56%	5.49%	9.48%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 180-trading day average as of December 31, 2021
[3] Source: Exhibit PAC 304
[4] Equals [3] + ([9] – [3]) / 6
[5] Equals [4] + ([9] – [3]) / 6
[6] Equals [5] + ([9] – [3]) / 6
[7] Equals [6] + ([9] – [3]) / 6
[8] Equals [7] + ([9] – [3]) / 6
[9] Source: Exhibit PAC 306
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

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

Company		1 Annualized Dividend	2 Stock Price	3 First Stage Growth Rate (high)	4 Year 6	5 Year 7	6 Year 8	7 Year 9	8 Year 10	9 Third Stage Growth Rate	10 ROE
ALLETE, Inc.	ALE	$2.52	$63.13	6.00%	5.91%	5.83%	5.74%	5.66%	5.57%	5.49%	10.04%
Alliant Energy Corporation	LNT	$1.61	$58.59	6.10%	6.00%	5.90%	5.79%	5.69%	5.59%	5.49%	8.61%
Ameren Corporation	AEE	$2.20	$86.40	7.90%	7.50%	7.10%	6.69%	6.29%	5.89%	5.49%	8.74%
American Electric Power Company, Inc.	AEP	$3.12	$84.96	6.50%	6.33%	6.16%	5.99%	5.82%	5.66%	5.49%	9.80%
Avista Corporation	AVA	$1.69	$40.41	6.20%	6.08%	5.96%	5.84%	5.72%	5.61%	5.49%	10.32%
CMS Energy Corporation	CMS	$1.74	$62.53	7.00%	6.75%	6.50%	6.24%	5.99%	5.74%	5.49%	8.85%
Duke Energy Corporation	DUK	$3.94	$101.53	7.00%	6.75%	6.50%	6.24%	5.99%	5.74%	5.49%	10.19%
Entergy Corporation	ETR	$4.04	$107.27	6.00%	5.91%	5.83%	5.74%	5.66%	5.57%	5.49%	9.78%
Evergy, Inc.	EVRG	$2.29	$66.43	8.00%	7.58%	7.16%	6.74%	6.32%	5.91%	5.49%	9.93%
IDACORP, Inc.	IDA	$3.00	$109.22	4.40%	4.58%	4.76%	4.94%	5.12%	5.31%	5.49%	8.27%
NextEra Energy, Inc.	NEE	$1.54	$89.80	10.50%	9.66%	8.83%	7.99%	7.16%	6.32%	5.49%	8.06%
NorthWestern Corporation	NWE	$2.48	$55.96	4.50%	4.66%	4.83%	4.99%	5.16%	5.32%	5.49%	10.09%
Otter Tail Corporation	OTTR	$1.56	$68.13	9.00%	8.41%	7.83%	7.24%	6.66%	6.07%	5.49%	8.62%
Portland General Electric Company	POR	$1.72	$51.06	8.60%	8.08%	7.56%	7.04%	6.52%	6.01%	5.49%	9.99%
Southern Company	SO	$2.64	$64.96	6.20%	6.08%	5.96%	5.84%	5.72%	5.61%	5.49%	10.18%
Xcel Energy Inc.	XEL	$1.83	$66.39	6.90%	6.66%	6.43%	6.19%	5.96%	5.72%	5.49%	8.79%
Median					6.50%	6.30%	6.09%	5.89%	5.69%	5.49%	9.79%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 30-trading day average as of December 31, 2021
[3] Source: Exhibit PAC 304
[4] Equals [3] + ([9] − [3]) / 6
[5] Equals [4] + ([9] − [3]) / 6
[6] Equals [5] + ([9] − [3]) / 6
[7] Equals [6] + ([9] − [3]) / 6
[8] Equals [7] + ([9] − [3]) / 6
[9] Source: Exhibit PAC 306
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

0

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

		1	2	3	4	5	6	7	8	9	10
Company		Annualized Dividend	Stock Price	First Stage Growth Rate (high)	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth Rate	ROE
ALLETE, Inc.	ALE	$2.52	$62.93	6.00%	5.91%	5.83%	5.74%	5.66%	5.57%	5.49%	10.05%
Alliant Energy Corporation	LNT	$1.61	$57.81	6.10%	6.00%	5.90%	5.79%	5.69%	5.59%	5.49%	8.66%
Ameren Corporation	AEE	$2.20	$85.14	7.90%	7.50%	7.10%	6.69%	6.29%	5.89%	5.49%	8.79%
American Electric Power Company, Inc.	AEP	$3.12	$84.99	6.50%	6.33%	6.16%	5.99%	5.82%	5.66%	5.49%	9.80%
Avista Corporation	AVA	$1.69	$40.38	6.20%	6.08%	5.96%	5.84%	5.72%	5.61%	5.49%	10.32%
CMS Energy Corporation	CMS	$1.74	$61.76	7.00%	6.75%	6.50%	6.24%	5.99%	5.74%	5.49%	8.89%
Duke Energy Corporation	DUK	$3.94	$101.55	7.00%	6.75%	6.50%	6.24%	5.99%	5.74%	5.49%	10.19%
Entergy Corporation	ETR	$4.04	$106.25	6.00%	5.91%	5.83%	5.74%	5.66%	5.57%	5.49%	9.82%
Evergy, Inc.	EVRG	$2.29	$65.27	8.00%	7.58%	7.16%	6.74%	6.32%	5.91%	5.49%	10.01%
IDACORP, Inc.	IDA	$3.00	$106.01	4.40%	4.58%	4.76%	4.94%	5.12%	5.31%	5.49%	8.36%
NextEra Energy, Inc.	NEE	$1.54	$85.45	10.50%	9.66%	8.83%	7.99%	7.16%	6.32%	5.49%	8.19%
NorthWestern Corporation	NWE	$2.48	$58.26	4.50%	4.66%	4.83%	4.99%	5.16%	5.32%	5.49%	9.91%
Otter Tail Corporation	OTTR	$1.56	$62.00	9.00%	8.41%	7.83%	7.24%	6.66%	6.07%	5.49%	8.94%
Portland General Electric Company	POR	$1.72	$49.88	8.60%	8.08%	7.56%	7.04%	6.52%	6.01%	5.49%	10.10%
Southern Company	SO	$2.64	$64.12	6.20%	6.08%	5.96%	5.84%	5.72%	5.61%	5.49%	10.24%
Xcel Energy Inc.	XEL	$1.83	$65.47	6.90%	6.66%	6.43%	6.19%	5.96%	5.72%	5.49%	8.84%
Median					6.50%	6.30%	6.09%	5.89%	5.69%	5.49%	9.81%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 90-trading day average as of December 31, 2021
[3] Source: Exhibit PAC 304
[4] Equals [3] + ([9] − [3]) / 6
[5] Equals [4] + ([9] − [3]) / 6
[6] Equals [5] + ([9] − [3]) / 6
[7] Equals [6] + ([9] − [3]) / 6
[8] Equals [7] + ([9] − [3]) / 6
[9] Source: Exhibit PAC 306
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

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

		1	2	3	4	5	6	7	8	9	10
Company		Annualized Dividend	Stock Price	First Stage Growth Rate (high)	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth Rate	ROE
ALLETE, Inc.	ALE	$2.52	$66.46	6.00%	5.91%	5.83%	5.74%	5.66%	5.57%	5.49%	9.81%
Alliant Energy Corporation	LNT	$1.61	$57.87	6.10%	6.00%	5.90%	5.79%	5.69%	5.59%	5.49%	8.65%
Ameren Corporation	AEE	$2.20	$84.84	7.90%	7.50%	7.10%	6.69%	6.29%	5.89%	5.49%	8.80%
American Electric Power Company, Inc.	AEP	$3.12	$85.87	6.50%	6.33%	6.16%	5.99%	5.82%	5.66%	5.49%	9.76%
Avista Corporation	AVA	$1.69	$42.34	6.20%	6.08%	5.96%	5.84%	5.72%	5.61%	5.49%	10.10%
CMS Energy Corporation	CMS	$1.74	$62.01	7.00%	6.75%	6.50%	6.24%	5.99%	5.74%	5.49%	8.88%
Duke Energy Corporation	DUK	$3.94	$102.02	7.00%	6.75%	6.50%	6.24%	5.99%	5.74%	5.49%	10.17%
Entergy Corporation	ETR	$4.04	$106.04	6.00%	5.91%	5.83%	5.74%	5.66%	5.57%	5.49%	9.83%
Evergy, Inc.	EVRG	$2.29	$64.59	8.00%	7.58%	7.16%	6.74%	6.32%	5.91%	5.49%	10.06%
IDACORP, Inc.	IDA	$3.00	$103.97	4.40%	4.58%	4.76%	4.94%	5.12%	5.31%	5.49%	8.42%
NextEra Energy, Inc.	NEE	$1.54	$80.89	10.50%	9.66%	8.83%	7.99%	7.16%	6.32%	5.49%	8.35%
NorthWestern Corporation	NWE	$2.48	$60.99	4.50%	4.66%	4.83%	4.99%	5.16%	5.32%	5.49%	9.70%
Otter Tail Corporation	OTTR	$1.56	$55.71	9.00%	8.41%	7.83%	7.24%	6.66%	6.07%	5.49%	9.33%
Portland General Electric Company	POR	$1.72	$49.44	8.60%	8.08%	7.56%	7.04%	6.52%	6.01%	5.49%	10.14%
Southern Company	SO	$2.64	$64.07	6.20%	6.08%	5.96%	5.84%	5.72%	5.61%	5.49%	10.25%
Xcel Energy Inc.	XEL	$1.83	$67.39	6.90%	6.66%	6.43%	6.19%	5.96%	5.72%	5.49%	8.74%
Median					6.50%	6.30%	6.09%	5.89%	5.69%	5.49%	9.73%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 180-trading day average as of December 31, 2021
[3] Source: Exhibit PAC 304
[4] Equals [3] + ([9] − [3]) / 6
[5] Equals [4] + ([9] − [3]) / 6
[6] Equals [5] + ([9] − [3]) / 6
[7] Equals [6] + ([9] − [3]) / 6
[8] Equals [7] + ([9] − [3]) / 6
[9] Source: Exhibit PAC 306
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

Docket No. UE 399
Exhibit PAC/306
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Ann E. Bulkley

Gross Domestic Product Growth

March 2022

Long-Term Growth Rate

CALCULATION OF LONG-TERM GDP GROWTH RATE				
Real GDP ($ Billions) [1]				
	1929	$		1,110.2
	2020	$		18,384.7
Compound Annual Growth Rate			**3.13%**	
Consumer Price Index (YoY % Change) [2]				
	2028-2032		2.20%	
Average			2.20%	
Consumer Price Index (All-Urban) [3]				
	2031			3.26
	2050			5.00
Compound Annual Growth Rate			2.27%	
GDP Chain-type Price Index (2012=1.000) [3]				
	2031			1.42
	2050			2.21
Compound Annual Growth Rate			2.37%	
Average Inflation Forecast			**2.28%**	
Long-Term GDP Growth Rate			**5.49%**	

Notes:

[1] Bureau of Economic Analysis, December 31, 2021

[2] Blue Chip Financial Forecasts, Vol. 40, No. 12, December 1, 2021 at 14

[3] Energy Information Administration, Annual Energy Outlook 2021 at Table 20, February 3, 2021

Docket No. UE 399
Exhibit PAC/307
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Ann E. Bulkley

Capital Asset Pricing Model

March 2022

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

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

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Current 30-day average of 30-year U.S. Treasury bond yield	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)	ECAPM ROE (K)
ALLETE, Inc.	ALE	1.87%	0.90	12.63%	10.76%	11.55%	11.82%
Alliant Energy Corporation	LNT	1.87%	0.85	12.63%	10.76%	11.01%	11.42%
Ameren Corporation	AEE	1.87%	0.80	12.63%	10.76%	10.47%	11.01%
American Electric Power Company, Inc.	AEP	1.87%	0.75	12.63%	10.76%	9.94%	10.61%
Avista Corporation	AVA	1.87%	0.95	12.63%	10.76%	12.09%	12.22%
CMS Energy Corporation	CMS	1.87%	0.80	12.63%	10.76%	10.47%	11.01%
Duke Energy Corporation	DUK	1.87%	0.85	12.63%	10.76%	11.01%	11.42%
Entergy Corporation	ETR	1.87%	0.95	12.63%	10.76%	12.09%	12.22%
Evergy, Inc.	EVRG	1.87%	0.95	12.63%	10.76%	12.09%	12.22%
IDACORP, Inc.	IDA	1.87%	0.80	12.63%	10.76%	10.47%	11.01%
NextEra Energy, Inc.	NEE	1.87%	0.90	12.63%	10.76%	11.55%	11.82%
NorthWestern Corporation	NWE	1.87%	0.95	12.63%	10.76%	12.09%	12.22%
Otter Tail Corporation	OTTR	1.87%	0.90	12.63%	10.76%	11.55%	11.82%
Portland General Electric Company	POR	1.87%	0.90	12.63%	10.76%	11.55%	11.82%
Southern Company	SO	1.87%	0.95	12.63%	10.76%	12.09%	12.22%
Xcel Energy Inc.	XEL	1.87%	0.80	12.63%	10.76%	10.47%	11.01%
Mean			0.88			11.28%	11.62%

Notes:
[1] Source: Bloomberg Professional, as of December 31, 2021
[2] Source: Value Line
[3] Source: PAC 307 p. 11
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

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

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

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q2 2022 - Q2 2023)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)	ECAPM ROE (K)
ALLETE, Inc.	ALE	2.52%	0.90	12.63%	10.11%	11.62%	11.87%
Alliant Energy Corporation	LNT	2.52%	0.85	12.63%	10.11%	11.11%	11.49%
Ameren Corporation	AEE	2.52%	0.80	12.63%	10.11%	10.60%	11.11%
American Electric Power Company, Inc.	AEP	2.52%	0.75	12.63%	10.11%	10.10%	10.73%
Avista Corporation	AVA	2.52%	0.95	12.63%	10.11%	12.12%	12.25%
CMS Energy Corporation	CMS	2.52%	0.80	12.63%	10.11%	10.60%	11.11%
Duke Energy Corporation	DUK	2.52%	0.85	12.63%	10.11%	11.11%	11.49%
Entergy Corporation	ETR	2.52%	0.95	12.63%	10.11%	12.12%	12.25%
Evergy, Inc.	EVRG	2.52%	0.95	12.63%	10.11%	12.12%	12.25%
IDACORP, Inc.	IDA	2.52%	0.80	12.63%	10.11%	10.60%	11.11%
NextEra Energy, Inc.	NEE	2.52%	0.90	12.63%	10.11%	11.62%	11.87%
NorthWestern Corporation	NWE	2.52%	0.95	12.63%	10.11%	12.12%	12.25%
Otter Tail Corporation	OTTR	2.52%	0.90	12.63%	10.11%	11.62%	11.87%
Portland General Electric Company	POR	2.52%	0.90	12.63%	10.11%	11.62%	11.87%
Southern Company	SO	2.52%	0.95	12.63%	10.11%	12.12%	12.25%
Xcel Energy Inc.	XEL	2.52%	0.80	12.63%	10.11%	10.60%	11.11%
Mean						11.36%	11.68%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 41, No. 1, January 1, 2022, at 2
[2] Source: Value Line
[3] Source: PAC 307 p. 11
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

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

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

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2023 - 2027)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)	ECAPM ROE (K)
ALLETE, Inc.	ALE	3.40%	0.90	12.63%	9.23%	11.70%	11.93%
Alliant Energy Corporation	LNT	3.40%	0.85	12.63%	9.23%	11.24%	11.59%
Ameren Corporation	AEE	3.40%	0.80	12.63%	9.23%	10.78%	11.24%
American Electric Power Company, Inc.	AEP	3.40%	0.75	12.63%	9.23%	10.32%	10.90%
Avista Corporation	AVA	3.40%	0.95	12.63%	9.23%	12.16%	12.28%
CMS Energy Corporation	CMS	3.40%	0.80	12.63%	9.23%	10.78%	11.24%
Duke Energy Corporation	DUK	3.40%	0.85	12.63%	9.23%	11.24%	11.59%
Entergy Corporation	ETR	3.40%	0.95	12.63%	9.23%	12.16%	12.28%
Evergy, Inc.	EVRG	3.40%	0.95	12.63%	9.23%	12.16%	12.28%
IDACORP, Inc.	IDA	3.40%	0.80	12.63%	9.23%	10.78%	11.24%
NextEra Energy, Inc.	NEE	3.40%	0.90	12.63%	9.23%	11.70%	11.93%
NorthWestern Corporation	NWE	3.40%	0.95	12.63%	9.23%	12.16%	12.28%
Otter Tail Corporation	OTTR	3.40%	0.90	12.63%	9.23%	11.70%	11.93%
Portland General Electric Company	POR	3.40%	0.90	12.63%	9.23%	11.70%	11.93%
Southern Company	SO	3.40%	0.95	12.63%	9.23%	12.16%	12.28%
Xcel Energy Inc.	XEL	3.40%	0.80	12.63%	9.23%	10.78%	11.24%
Mean						11.47%	11.76%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 40, No. 12, December 1, 2021, at 14
[2] Source: Value Line
[3] Source: PAC 307 p. 11
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

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

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

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Current 30-day average of 30-year U.S. Treasury bond yield	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)	ECAPM ROE (K)
ALLETE, Inc.	ALE	1.87%	0.85	12.63%	10.76%	11.03%	11.43%
Alliant Energy Corporation	LNT	1.87%	0.81	12.63%	10.76%	10.55%	11.07%
Ameren Corporation	AEE	1.87%	0.76	12.63%	10.76%	10.06%	10.70%
American Electric Power Company, Inc.	AEP	1.87%	0.78	12.63%	10.76%	10.29%	10.87%
Avista Corporation	AVA	1.87%	0.78	12.63%	10.76%	10.29%	10.87%
CMS Energy Corporation	CMS	1.87%	0.75	12.63%	10.76%	9.96%	10.62%
Duke Energy Corporation	DUK	1.87%	0.73	12.63%	10.76%	9.68%	10.42%
Entergy Corporation	ETR	1.87%	0.87	12.63%	10.76%	11.23%	11.58%
Evergy, Inc.	EVRG	1.87%	0.80	12.63%	10.76%	10.51%	11.04%
IDACORP, Inc.	IDA	1.87%	0.83	12.63%	10.76%	10.84%	11.29%
NextEra Energy, Inc.	NEE	1.87%	0.78	12.63%	10.76%	10.30%	10.88%
NorthWestern Corporation	NWE	1.87%	0.92	12.63%	10.76%	11.76%	11.98%
Otter Tail Corporation	OTTR	1.87%	0.89	12.63%	10.76%	11.43%	11.73%
Portland General Electric Company	POR	1.87%	0.82	12.63%	10.76%	10.68%	11.16%
Southern Company	SO	1.87%	0.79	12.63%	10.76%	10.39%	10.95%
Xcel Energy Inc.	XEL	1.87%	0.75	12.63%	10.76%	9.94%	10.61%
Mean						10.56%	11.08%

Notes:
[1] Source: Bloomberg Professional, as of December 31, 2021
[2] Source: Bloomberg Professional, based on 10-year weekly returns
[3] Source: PAC 307 p. 11
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

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

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

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q2 2022 - Q2 2023)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)	ECAPM ROE (K)
ALLETE, Inc.	ALE	2.52%	0.85	12.63%	10.11%	11.13%	11.50%
Alliant Energy Corporation	LNT	2.52%	0.81	12.63%	10.11%	10.68%	11.16%
Ameren Corporation	AEE	2.52%	0.76	12.63%	10.11%	10.22%	10.82%
American Electric Power Company, Inc.	AEP	2.52%	0.78	12.63%	10.11%	10.43%	10.98%
Avista Corporation	AVA	2.52%	0.78	12.63%	10.11%	10.43%	10.98%
CMS Energy Corporation	CMS	2.52%	0.75	12.63%	10.11%	10.12%	10.75%
Duke Energy Corporation	DUK	2.52%	0.73	12.63%	10.11%	9.86%	10.55%
Entergy Corporation	ETR	2.52%	0.87	12.63%	10.11%	11.31%	11.64%
Evergy, Inc.	EVRG	2.52%	0.80	12.63%	10.11%	10.64%	11.14%
IDACORP, Inc.	IDA	2.52%	0.83	12.63%	10.11%	10.95%	11.37%
NextEra Energy, Inc.	NEE	2.52%	0.78	12.63%	10.11%	10.45%	10.99%
NorthWestern Corporation	NWE	2.52%	0.92	12.63%	10.11%	11.81%	12.02%
Otter Tail Corporation	OTTR	2.52%	0.89	12.63%	10.11%	11.50%	11.78%
Portland General Electric Company	POR	2.52%	0.82	12.63%	10.11%	10.80%	11.25%
Southern Company	SO	2.52%	0.79	12.63%	10.11%	10.53%	11.05%
Xcel Energy Inc.	XEL	2.52%	0.75	12.63%	10.11%	10.10%	10.73%
Mean						10.68%	11.17%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 41, No. 1, January 1, 2022, at 2
[2] Source: Bloomberg Professional, based on 10-year weekly returns
[3] Source: PAC 307 p. 11
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

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

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

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2023 - 2027)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)	ECAPM ROE (K)
ALLETE, Inc.	ALE	3.40%	0.85	12.63%	9.23%	11.26%	11.60%
Alliant Energy Corporation	LNT	3.40%	0.81	12.63%	9.23%	10.85%	11.29%
Ameren Corporation	AEE	3.40%	0.76	12.63%	9.23%	10.43%	10.98%
American Electric Power Company, Inc.	AEP	3.40%	0.78	12.63%	9.23%	10.62%	11.12%
Avista Corporation	AVA	3.40%	0.78	12.63%	9.23%	10.62%	11.12%
CMS Energy Corporation	CMS	3.40%	0.75	12.63%	9.23%	10.34%	10.91%
Duke Energy Corporation	DUK	3.40%	0.73	12.63%	9.23%	10.10%	10.73%
Entergy Corporation	ETR	3.40%	0.87	12.63%	9.23%	11.43%	11.73%
Evergy, Inc.	EVRG	3.40%	0.80	12.63%	9.23%	10.82%	11.27%
IDACORP, Inc.	IDA	3.40%	0.83	12.63%	9.23%	11.09%	11.48%
NextEra Energy, Inc.	NEE	3.40%	0.78	12.63%	9.23%	10.64%	11.13%
NorthWestern Corporation	NWE	3.40%	0.92	12.63%	9.23%	11.88%	12.07%
Otter Tail Corporation	OTTR	3.40%	0.89	12.63%	9.23%	11.60%	11.86%
Portland General Electric Company	POR	3.40%	0.82	12.63%	9.23%	10.96%	11.37%
Southern Company	SO	3.40%	0.79	12.63%	9.23%	10.71%	11.19%
Xcel Energy Inc.	XEL	3.40%	0.75	12.63%	9.23%	10.32%	10.90%
Mean						10.85%	11.30%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 40, No. 12, December 1, 2021, at 14
[2] Source: Bloomberg Professional, based on 10-year weekly returns
[3] Source: PAC 307 p. 11
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

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

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

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Current 30-day average of 30-year U.S. Treasury bond yield	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)	ECAPM ROE (K)
ALLETE, Inc.	ALE	1.87%	0.76	12.63%	10.76%	10.03%	10.68%
Alliant Energy Corporation	LNT	1.87%	0.74	12.63%	10.76%	9.79%	10.50%
Ameren Corporation	AEE	1.87%	0.73	12.63%	10.76%	9.69%	10.43%
American Electric Power Company, Inc.	AEP	1.87%	0.67	12.63%	10.76%	9.06%	9.95%
Avista Corporation	AVA	1.87%	0.75	12.63%	10.76%	9.94%	10.61%
CMS Energy Corporation	CMS	1.87%	0.69	12.63%	10.76%	9.30%	10.13%
Duke Energy Corporation	DUK	1.87%	0.64	12.63%	10.76%	8.76%	9.73%
Entergy Corporation	ETR	1.87%	0.72	12.63%	10.76%	9.59%	10.35%
Evergy, Inc.	EVRG	1.87%	0.98	12.63%	10.76%	12.36%	12.42%
IDACORP, Inc.	IDA	1.87%	0.72	12.63%	10.76%	9.59%	10.35%
NextEra Energy, Inc.	NEE	1.87%	0.71	12.63%	10.76%	9.50%	10.28%
NorthWestern Corporation	NWE	1.87%	0.72	12.63%	10.76%	9.64%	10.39%
Otter Tail Corporation	OTTR	1.87%	0.86	12.63%	10.76%	11.11%	11.49%
Portland General Electric Company	POR	1.87%	0.75	12.63%	10.76%	9.89%	10.57%
Southern Company	SO	1.87%	0.61	12.63%	10.76%	8.47%	9.51%
Xcel Energy Inc.	XEL	1.87%	0.65	12.63%	10.76%	8.86%	9.80%
Mean						9.72%	10.45%

Notes:
[1] Source: Bloomberg Professional, as of December 31, 2021
[2] Source: PAC 307 p. 10
[3] Source: PAC 307 p. 11
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

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

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

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q2 2022 - Q2 2023)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)	ECAPM ROE (K)
ALLETE, Inc.	ALE	2.52%	0.76	12.63%	10.11%	10.19%	10.80%
Alliant Energy Corporation	LNT	2.52%	0.74	12.63%	10.11%	9.96%	10.63%
Ameren Corporation	AEE	2.52%	0.73	12.63%	10.11%	9.87%	10.56%
American Electric Power Company, Inc.	AEP	2.52%	0.67	12.63%	10.11%	9.27%	10.11%
Avista Corporation	AVA	2.52%	0.75	12.63%	10.11%	10.10%	10.73%
CMS Energy Corporation	CMS	2.52%	0.69	12.63%	10.11%	9.50%	10.28%
Duke Energy Corporation	DUK	2.52%	0.64	12.63%	10.11%	9.00%	9.90%
Entergy Corporation	ETR	2.52%	0.72	12.63%	10.11%	9.78%	10.49%
Evergy, Inc.	EVRG	2.52%	0.98	12.63%	10.11%	12.37%	12.44%
IDACORP, Inc.	IDA	2.52%	0.72	12.63%	10.11%	9.78%	10.49%
NextEra Energy, Inc.	NEE	2.52%	0.71	12.63%	10.11%	9.69%	10.42%
NorthWestern Corporation	NWE	2.52%	0.72	12.63%	10.11%	9.82%	10.52%
Otter Tail Corporation	OTTR	2.52%	0.86	12.63%	10.11%	11.20%	11.56%
Portland General Electric Company	POR	2.52%	0.75	12.63%	10.11%	10.05%	10.70%
Southern Company	SO	2.52%	0.61	12.63%	10.11%	8.72%	9.70%
Xcel Energy Inc.	XEL	2.52%	0.65	12.63%	10.11%	9.09%	9.97%
Mean						9.90%	10.58%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 41, No. 1, January 1, 2022, at 2
[2] Source: PAC 307 p. 10
[3] Source: PAC 307 p. 11
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

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

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

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2023 - 2027)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	ROE (K)	ECAPM ROE (K)
ALLETE, Inc.	ALE	3.40%	0.76	12.63%	9.23%	10.40%	10.96%
Alliant Energy Corporation	LNT	3.40%	0.74	12.63%	9.23%	10.19%	10.80%
Ameren Corporation	AEE	3.40%	0.73	12.63%	9.23%	10.11%	10.74%
American Electric Power Company, Inc.	AEP	3.40%	0.67	12.63%	9.23%	9.56%	10.33%
Avista Corporation	AVA	3.40%	0.75	12.63%	9.23%	10.32%	10.90%
CMS Energy Corporation	CMS	3.40%	0.69	12.63%	9.23%	9.77%	10.49%
Duke Energy Corporation	DUK	3.40%	0.64	12.63%	9.23%	9.31%	10.14%
Entergy Corporation	ETR	3.40%	0.72	12.63%	9.23%	10.03%	10.68%
Evergy, Inc.	EVRG	3.40%	0.98	12.63%	9.23%	12.40%	12.45%
IDACORP, Inc.	IDA	3.40%	0.72	12.63%	9.23%	10.03%	10.68%
NextEra Energy, Inc.	NEE	3.40%	0.71	12.63%	9.23%	9.94%	10.61%
NorthWestern Corporation	NWE	3.40%	0.72	12.63%	9.23%	10.07%	10.71%
Otter Tail Corporation	OTTR	3.40%	0.86	12.63%	9.23%	11.33%	11.65%
Portland General Electric Company	POR	3.40%	0.75	12.63%	9.23%	10.28%	10.86%
Southern Company	SO	3.40%	0.61	12.63%	9.23%	9.06%	9.95%
Xcel Energy Inc.	XEL	3.40%	0.65	12.63%	9.23%	9.40%	10.20%
Mean						10.14%	10.76%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 40, No. 12, December 1, 2021, at 14
[2] Source: PAC 307 p. 10
[3] Source: PAC 307 p. 11
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

HISTORICAL BETA - 2011 - 2020

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	12/31/2011	12/31/2012	12/31/2013	12/31/2014	12/31/2015	12/31/2016	12/31/2017	12/31/2018	12/31/2019	12/31/2020	12/31/2021	Average
ALLETE, Inc.	ALE	0.70	0.70	0.75	0.80	0.80	0.75	0.80	0.65	0.65	0.85	0.90	0.76
Alliant Energy Corporation	LNT	0.75	0.70	0.75	0.80	0.80	0.70	0.70	0.60	0.60	0.85	0.85	0.74
Ameren Corporation	AEE	0.80	0.80	0.80	0.75	0.75	0.65	0.70	0.55	0.55	0.85	0.80	0.73
American Electric Power Company, Inc.	AEP	0.70	0.65	0.70	0.70	0.70	0.65	0.65	0.55	0.55	0.75	0.75	0.67
Avista Corporation	AVA	0.70	0.70	0.70	0.80	0.80	0.70	0.75	0.65	0.60	0.90	0.95	0.75
CMS Energy Corporation	CMS	0.75	0.75	0.70	0.70	0.75	0.65	0.65	0.55	0.50	0.80	0.80	0.69
Duke Energy Corporation	DUK	0.65	0.60	0.65	0.60	0.65	0.60	0.60	0.50	0.50	0.85	0.85	0.64
Entergy Corporation	ETR	0.70	0.70	0.70	0.70	0.70	0.65	0.65	0.60	0.60	0.95	0.95	0.72
Evergy, Inc.	EVRG								NMF	NMF	1.00	0.95	0.98
IDACORP, Inc.	IDA	0.70	0.70	0.70	0.80	0.80	0.75	0.70	0.60	0.55	0.80	0.80	0.72
NextEra Energy, Inc.	NEE	0.75	0.70	0.70	0.70	0.75	0.65	0.65	0.55	0.55	0.90	0.90	0.71
NorthWestern Corporation	NWE	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.60	0.60	0.90	0.95	0.72
Otter Tail Corporation	OTTR	0.90	0.90	0.95	0.90	0.85	0.85	0.90	0.75	0.70	0.85	0.90	0.86
Portland General Electric Company	POR	0.75	0.75	0.75	0.80	0.80	0.70	0.70	0.60	0.60	0.85	0.90	0.75
Southern Company	SO	0.55	0.55	0.55	0.55	0.60	0.55	0.55	0.50	0.50	0.90	0.95	0.61
Xcel Energy Inc.	XEL	0.65	0.65	0.65	0.70	0.65	0.60	0.60	0.55	0.50	0.80	0.80	0.65
Mean		0.72	0.70	0.72	0.73	0.74	0.68	0.69	0.59	0.57	0.86	0.88	0.73

Notes:
[1] Value Line, dated November 4, 2011, November 25, 2011, and December 23, 2011.
[2] Value Line, dated November 2, 2012, November 23, 2012, and December 21, 2012.
[3] Value Line, dated November 1, 2013, November 22, 2013, and December 20, 2013.
[4] Value Line, dated October 31, 2014, November 21, 2014, and December 19, 2014.
[5] Value Line, dated October 30,2015, November 20, 2015, and December 18, 2015.
[6] Value Line, dated October 28, 2016, November 18, 2016, and December 16, 2016.
[7] Value Line, dated October 27, 2017, November 17, 2017, and December 15, 2017.
[8] Value Line, dated October 18, 2018, November 16, 2018, and Decenber 14, 2018.
[9] Value Line, dated October 25, 2019, November 15, 2019, and December 13, 2019.
[10] Value Line, dated October 23, 2020, November 13, 2020, and December 11, 2020.
[11] Value Line, dated September 10, 2021, October 22, 2021, November 12, 2021, and December 10, 2021.
[12] Average ([1] - [11])

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

[1] Estimated Weighted Average Dividend Yield	1.48%
[2] Estimated Weighted Average Long-Term Growth Rate	11.06%
[3] S&P 500 Estimated Required Market Return	12.63%

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[4] Shares Outst'g	[5] Price	[6] Market Capitalization	[7] Weight in Index	[8] Estimated Dividend Yield	[9] Cap-Weighted Dividend Yield	[10] Value Line Long-Term Growth Est.	[11] Cap-Weighted Long-Term Growth Est.
LyondellBasell Industries NV	LYB	332.78	92.23	30,692.67	0.10%	4.90%	0.00%	8.00%	0.01%
Signature Bank/New York NY	SBNY	60.47	323.47	19,559.91	0.06%	0.69%	0.00%	12.00%	0.01%
American Express Co	AXP	774.56	163.60	126,717.36	0.39%	1.05%	0.00%	8.50%	0.03%
Verizon Communications Inc	VZ	4,197.76	51.96	218,115.61	0.68%	4.93%	0.03%	2.50%	0.02%
Broadcom Inc	AVGO	412.87	665.41	274,730.49		2.46%		27.00%	
Boeing Co/The	BA	587.70	201.32	118,315.56		n/a			
Caterpillar Inc	CAT	540.94	206.74	111,834.35	0.35%	2.15%	0.01%	9.50%	0.03%
JPMorgan Chase & Co	JPM	2,955.27	158.35	467,966.37	1.46%	2.53%	0.04%	7.50%	0.11%
Chevron Corp	CVX	1,927.69	117.35	226,213.95		4.57%		24.00%	
Coca-Cola Co/The	KO	4,319.42	59.21	255,752.86	0.80%	2.84%	0.02%	7.00%	0.06%
AbbVie Inc	ABBV	1,767.88	135.40	239,370.95	0.74%	4.17%	0.03%	6.50%	0.05%
Walt Disney Co/The	DIS	1,817.66	154.89	281,536.74	0.88%	n/a		14.00%	0.12%
FleetCor Technologies Inc	FLT	81.20	223.84	18,175.58	0.06%	n/a		11.00%	0.01%
Extra Space Storage Inc	EXR	133.89	226.73	30,357.33	0.09%	2.21%	0.00%	5.50%	0.01%
Exxon Mobil Corp	XOM	4,233.57	61.19	259,051.96		5.75%		31.00%	
Phillips 66	PSX	438.17	72.46	31,749.80	0.10%	5.08%	0.01%	20.00%	0.02%
General Electric Co	GE	1,098.14	94.47	103,741.00	0.32%	0.34%	0.00%	15.00%	0.05%
HP Inc	HPQ	1,082.72	37.67	40,786.18	0.13%	2.65%	0.00%	15.50%	0.02%
Home Depot Inc/The	HD	1,044.24	415.01	433,369.63	1.35%	1.59%	0.02%	11.00%	0.15%
Monolithic Power Systems Inc	MPWR	46.09	493.33	22,739.06		0.49%		20.50%	
International Business Machines Corp	IBM	896.80	133.66	119,866.29	0.37%	4.91%	0.02%	0.50%	0.00%
Johnson & Johnson	JNJ	2,632.60	171.07	450,358.37	1.40%	2.48%	0.03%	10.00%	0.14%
McDonald's Corp	MCD	747.25	268.07	200,313.97	0.62%	2.06%	0.01%	10.50%	0.07%
Merck & Co Inc	MRK	2,525.94	76.64	193,588.35	0.60%	3.60%	0.02%	7.50%	0.05%
3M Co	MMM	576.25	177.63	102,359.82	0.32%	3.33%	0.01%	6.00%	0.02%
American Water Works Co Inc	AWK	181.54	188.86	34,285.27	0.11%	1.28%	0.00%	8.50%	0.01%
Bank of America Corp	BAC	8,184.08	44.49	364,109.90	1.13%	1.89%	0.02%	7.50%	0.08%
Pfizer Inc	PFE	5,612.87	59.05	331,439.80	1.03%	2.71%	0.03%	11.50%	0.12%
Procter & Gamble Co/The	PG	2,419.95	163.58	395,855.09	1.23%	2.13%	0.03%	7.00%	0.09%
AT&T Inc	T	7,141.00	24.60	175,668.60	0.55%	8.46%	0.05%	1.50%	0.01%
Travelers Cos Inc/The	TRV	246.01	156.43	38,483.19	0.12%	2.25%	0.00%	8.00%	0.01%
Raytheon Technologies Corp	RTX	1,496.78	86.06	128,812.71	0.40%	2.37%	0.01%	1.50%	0.01%
Analog Devices Inc	ADI	525.33	175.77	92,337.43	0.29%	1.57%	0.00%	11.00%	0.03%
Walmart Inc	WMT	2,773.88	144.69	401,352.41	1.25%	1.52%	0.02%	7.50%	0.09%
Cisco Systems Inc/Delaware	CSCO	4,217.61	63.37	267,269.76	0.83%	2.34%	0.02%	7.00%	0.06%
Intel Corp	INTC	4,067.00	51.50	209,450.50	0.65%	2.70%	0.02%	7.00%	0.05%
General Motors Co	GM	1,451.86	58.63	85,122.55	0.26%	n/a		12.00%	0.03%
Microsoft Corp	MSFT	7,507.98	336.32	2,525,083.83	7.85%	0.74%	0.06%	15.00%	1.18%
Dollar General Corp	DG	231.71	235.83	54,643.46	0.17%	0.71%	0.00%	10.50%	0.02%
Cigna Corp	CI	331.43	229.63	76,105.81	0.24%	1.74%	0.00%	10.00%	0.02%
Kinder Morgan Inc	KMI	2,267.43	15.86	35,961.38	0.11%	6.81%	0.01%	19.00%	0.02%
Citigroup Inc	C	1,984.27	60.39	119,829.88	0.37%	3.38%	0.01%	7.00%	0.03%
American International Group Inc	AIG	830.30	56.86	47,210.74		2.25%		31.50%	
Altria Group Inc	MO	1,836.99	47.39	87,054.91	0.27%	7.60%	0.02%	6.00%	0.02%
HCA Healthcare Inc	HCA	311.02	256.92	79,908.03	0.25%	0.75%	0.00%	13.50%	0.03%
Under Armour Inc	UAA	188.65	21.19	3,997.41		n/a		33.00%	
International Paper Co	IP	387.26	46.98	18,193.62	0.06%	3.94%	0.00%	12.00%	0.01%
Hewlett Packard Enterprise Co	HPE	1,293.44	15.77	20,397.55	0.06%	3.04%	0.00%	6.50%	0.00%
Abbott Laboratories	ABT	1,768.29	140.74	248,868.71	0.77%	1.34%	0.01%	11.50%	0.09%
Aflac Inc	AFL	661.53	58.39	38,626.62	0.12%	2.74%	0.00%	11.00%	0.01%
Air Products and Chemicals Inc	APD	221.68	304.26	67,449.57	0.21%	1.97%	0.00%	12.50%	0.03%
Royal Caribbean Cruises Ltd	RCL	254.79	76.90	19,593.35		n/a			
Hess Corp	HES	309.73	74.03	22,929.09		1.35%			
Archer-Daniels-Midland Co	ADM	559.44	67.59	37,812.62	0.12%	2.19%	0.00%	9.50%	0.01%
Automatic Data Processing Inc	ADP	421.38	246.58	103,904.87	0.32%	1.69%	0.01%	8.50%	0.03%
Verisk Analytics Inc	VRSK	161.16	228.73	36,862.36	0.11%	0.51%	0.00%	11.50%	0.01%
AutoZone Inc	AZO	20.63	2,096.39	43,256.91	0.13%	n/a		15.00%	0.02%
Avery Dennison Corp	AVY	82.80	216.57	17,931.13	0.06%	1.26%	0.00%	9.00%	0.01%
Enphase Energy Inc	ENPH	134.91	182.94	24,680.80		n/a		40.00%	
MSCI Inc	MSCI	82.45	612.69	50,514.45	0.16%	0.68%	0.00%	16.00%	0.03%
Ball Corp	BLL	323.89	96.27	31,181.28		0.83%		21.00%	
Ceridian HCM Holding Inc	CDAY	151.33	104.46	15,808.04		n/a			
Carrier Global Corp	CARR	866.59	54.24	47,003.57		1.11%			
Bank of New York Mellon Corp/The	BK	825.82	58.08	47,963.68	0.15%	2.34%	0.00%	5.00%	0.01%
Otis Worldwide Corp	OTIS	424.77	87.07	36,984.64		1.10%			
Baxter International Inc	BAX	500.69	85.84	42,979.49	0.13%	1.30%	0.00%	8.50%	0.01%
Becton Dickinson and Co	BDX	285.04	251.48	71,682.61	0.22%	1.38%	0.00%	7.50%	0.02%
Berkshire Hathaway Inc	BRK/B	1,303.48	299.00	389,739.62	1.21%	n/a		6.00%	0.07%
Best Buy Co Inc	BBY	240.56	101.60	24,441.00	0.08%	2.76%	0.00%	8.50%	0.01%
Boston Scientific Corp	BSX	1,424.99	42.48	60,533.66	0.19%	n/a		17.50%	0.03%
Bristol-Myers Squibb Co	BMY	2,219.65	62.35	138,394.87	0.43%	3.46%	0.01%	12.50%	0.05%
Fortune Brands Home & Security Inc	FBHS	135.73	106.90	14,509.96	0.05%	1.05%	0.00%	11.00%	0.00%
Brown-Forman Corp	BF/B	309.74	72.86	22,567.87	0.07%	1.03%	0.00%	13.00%	0.01%
Coterra Energy Inc	CTRA	813.58	19.00	15,457.98		2.63%			
Campbell Soup Co	CPB	301.74	43.46	13,113.53	0.04%	3.41%	0.00%	5.50%	0.00%
Hilton Worldwide Holdings Inc	HLT	278.72	155.99	43,477.84		n/a			
Carnival Corp	CCL	981.05	20.12	19,738.69		n/a			
Qorvo Inc	QRVO	110.22	156.39	17,237.77		n/a		27.00%	
Lumen Technologies Inc	LUMN	1,023.89	12.55	12,849.87	0.04%	7.97%	0.00%	3.50%	0.00%

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[4] Shares Outst'g	[5] Price	[6] Market Capitalization	[7] Weight in Index	[8] Estimated Dividend Yield	[9] Cap-Weighted Dividend Yield	[10] Value Line Long-Term Growth Est.	[11] Cap-Weighted Long-Term Growth Est.
UDR Inc	UDR	309.19	59.99	18,548.07	0.06%	2.42%	0.00%	6.00%	0.00%
Clorox Co/The	CLX	122.86	174.36	21,422.39	0.07%	2.66%	0.00%	5.00%	0.00%
Paycom Software Inc	PAYC	60.03	415.19	24,922.19	0.08%	n/a		19.50%	0.02%
CMS Energy Corp	CMS	289.70	65.05	18,844.79	0.06%	2.67%	0.00%	6.00%	0.00%
Newell Brands Inc	NWL	425.40	21.84	9,290.74		4.21%			
Colgate-Palmolive Co	CL	842.85	85.34	71,928.73	0.22%	2.11%	0.00%	5.00%	0.01%
EPAM Systems Inc	EPAM	56.72	668.45	37,914.48		n/a		23.50%	
Comerica Inc	CMA	131.15	87.00	11,409.96	0.04%	3.13%	0.00%	2.50%	0.00%
IPG Photonics Corp	IPGP	53.31	172.14	9,176.61	0.03%	n/a		17.00%	0.00%
Conagra Brands Inc	CAG	479.69	34.15	16,381.41	0.05%	3.66%	0.00%	4.50%	0.00%
Consolidated Edison Inc	ED	353.75	85.32	30,181.86	0.09%	3.63%	0.00%	3.00%	0.00%
Corning Inc	GLW	853.41	37.23	31,772.38	0.10%	2.58%	0.00%	20.00%	0.02%
Cummins Inc	CMI	143.03	218.14	31,201.00	0.10%	2.66%	0.00%	7.00%	0.01%
Caesars Entertainment Inc	CZR	213.77	93.53	19,994.28		n/a			
Danaher Corp	DHR	714.58	329.01	235,102.98		0.26%		21.00%	
Target Corp	TGT	479.12	231.44	110,888.46	0.34%	1.56%	0.01%	15.00%	0.05%
Deere & Co	DE	307.41	342.89	105,406.79		1.22%		21.50%	
Dominion Energy Inc	D	810.00	78.56	63,633.60	0.20%	3.21%	0.01%	12.00%	0.02%
Dover Corp	DOV	143.99	181.60	26,147.68	0.08%	1.10%	0.00%	9.00%	0.01%
Alliant Energy Corp	LNT	250.36	61.47	15,389.69	0.05%	2.62%	0.00%	5.50%	0.00%
Duke Energy Corp	DUK	769.00	104.90	80,668.10	0.25%	3.76%	0.01%	7.00%	0.02%
Regency Centers Corp	REG	171.21	75.35	12,900.90	0.04%	3.32%	0.00%	16.00%	0.01%
Eaton Corp PLC	ETN	398.60	172.82	68,886.05	0.21%	1.76%	0.00%	11.50%	0.02%
Ecolab Inc	ECL	286.57	234.59	67,225.75	0.21%	0.87%	0.00%	6.00%	0.01%
PerkinElmer Inc	PKI	126.20	201.06	25,373.77	0.08%	0.14%	0.00%	12.00%	0.01%
Emerson Electric Co	EMR	595.70	92.97	55,382.14	0.17%	2.22%	0.00%	11.50%	0.02%
EOG Resources Inc	EOG	585.09	88.83	51,973.54	0.16%	3.38%	0.01%	16.00%	0.03%
Aon PLC	AON	220.33	300.56	66,222.99	0.21%	0.68%	0.00%	7.00%	0.01%
Entergy Corp	ETR	200.98	112.65	22,640.51	0.07%	3.59%	0.00%	3.00%	0.00%
Equifax Inc	EFX	122.00	292.79	35,720.97	0.11%	0.53%	0.00%	11.00%	0.01%
IQVIA Holdings Inc	IQV	191.04	282.14	53,900.03	0.17%	n/a		15.50%	0.03%
Gartner Inc	IT	82.24	334.32	27,494.14		n/a		20.50%	
FedEx Corp	FDX	264.97	258.64	68,531.58	0.21%	1.16%	0.00%	13.00%	0.03%
FMC Corp	FMC	126.75	109.89	13,928.67	0.04%	1.93%	0.00%	10.50%	0.00%
Brown & Brown Inc	BRO	282.43	70.28	19,848.97	0.06%	0.58%	0.00%	9.50%	0.01%
Ford Motor Co	F	3,925.39	20.77	81,530.33		1.93%		47.50%	
NextEra Energy Inc	NEE	1,962.14	93.36	183,185.11	0.57%	1.65%	0.01%	10.50%	0.06%
Franklin Resources Inc	BEN	501.80	33.49	16,805.11	0.05%	3.46%	0.00%	8.50%	0.00%
Garmin Ltd	GRMN	192.32	136.17	26,188.49	0.08%	1.97%	0.00%	10.00%	0.01%
Freeport-McMoRan Inc	FCX	1,468.47	41.73	61,279.42		0.72%		37.50%	
Gap Inc/The	GPS	373.40	17.65	6,590.56		2.72%		27.00%	
Dexcom Inc	DXCM	96.92	536.95	52,042.27		n/a		38.50%	
General Dynamics Corp	GD	279.22	208.47	58,209.62	0.18%	2.28%	0.00%	6.00%	0.01%
General Mills Inc	GIS	603.21	67.38	40,644.09	0.13%	3.03%	0.00%	3.50%	0.00%
Genuine Parts Co	GPC	142.42	140.20	19,967.56	0.06%	2.33%	0.00%	7.00%	0.00%
Atmos Energy Corp	ATO	132.71	104.77	13,903.50	0.04%	2.60%	0.00%	7.00%	0.00%
WW Grainger Inc	GWW	51.52	518.24	26,699.72	0.08%	1.25%	0.00%	6.50%	0.01%
Halliburton Co	HAL	895.12	22.87	20,471.30	0.06%	0.79%	0.00%	9.00%	0.01%
L3Harris Technologies Inc	LHX	196.23	213.24	41,843.02		1.91%			
Healthpeak Properties Inc	PEAK	539.07	36.09	19,455.11		3.33%		-12.00%	
Catalent Inc	CTLT	171.19	128.03	21,917.20		n/a		21.00%	
Fortive Corp	FTV	358.58	76.29	27,355.92	0.09%	0.37%	0.00%	6.00%	0.01%
Hershey Co/The	HSY	145.39	193.47	28,128.60	0.09%	1.86%	0.00%	6.00%	0.01%
Synchrony Financial	SYF	547.26	46.39	25,387.35	0.08%	1.90%	0.00%	9.50%	0.01%
Hormel Foods Corp	HRL	542.57	48.81	26,482.84	0.08%	2.13%	0.00%	9.00%	0.01%
Arthur J Gallagher & Co	AJG	207.28	169.67	35,168.86	0.11%	1.13%	0.00%	13.50%	0.01%
Mondelez International Inc	MDLZ	1,394.97	66.31	92,500.59	0.29%	2.11%	0.01%	8.00%	0.02%
CenterPoint Energy Inc	CNP	628.87	27.91	17,551.65	0.05%	2.44%	0.00%	4.50%	0.00%
Humana Inc	HUM	128.53	463.86	59,621.78	0.19%	0.60%	0.00%	12.00%	0.02%
Willis Towers Watson PLC	WLTW	124.61	237.49	29,592.68	0.09%	1.35%	0.00%	8.00%	0.01%
Illinois Tool Works Inc	ITW	313.88	246.80	77,465.83	0.24%	1.98%	0.00%	10.50%	0.03%
CDW Corp/DE	CDW	135.72	204.78	27,793.36	0.09%	0.98%	0.00%	10.00%	0.01%
Trane Technologies PLC	TT	237.54	202.03	47,990.21		1.17%			
Interpublic Group of Cos Inc/The	IPG	393.76	37.45	14,746.12	0.05%	2.88%	0.00%	12.00%	0.01%
International Flavors & Fragrances Inc	IFF	254.55	150.65	38,347.51	0.12%	2.10%	0.00%	7.50%	0.01%
Jacobs Engineering Group Inc	J	129.45	139.23	18,023.74	0.06%	0.60%	0.00%	15.00%	0.01%
Generac Holdings Inc	GNRC	63.09	351.92	22,202.63		n/a		23.50%	
NXP Semiconductors NV	NXPI	265.93	227.78	60,574.22	0.19%	0.99%	0.00%	11.00%	0.02%
Kellogg Co	K	341.12	64.42	21,975.14	0.07%	3.60%	0.00%	3.50%	0.00%
Broadridge Financial Solutions Inc	BR	116.58	182.82	21,312.79	0.07%	1.40%	0.00%	9.50%	0.01%
Kimberly-Clark Corp	KMB	336.72	142.92	48,123.59	0.15%	3.19%	0.00%	4.50%	0.01%
Kimco Realty Corp	KIM	616.43	24.65	15,194.95	0.05%	2.76%	0.00%	10.50%	0.00%
Oracle Corp	ORCL	2,670.45	87.21	232,889.68	0.72%	1.47%	0.01%	10.00%	0.07%
Kroger Co/The	KR	735.26	45.26	33,277.69	0.10%	1.86%	0.00%	6.00%	0.01%
Lennar Corp	LEN	271.85	116.16	31,578.33	0.10%	0.86%	0.00%	12.50%	0.01%
Eli Lilly & Co	LLY	956.59	276.22	264,229.84	0.82%	1.42%	0.01%	12.00%	0.10%
Bath & Body Works Inc	BBWI	257.72	69.79	17,986.49		0.86%		26.00%	
Charter Communications Inc	CHTR	179.29	651.97	116,892.35		n/a		29.50%	
Lincoln National Corp	LNC	180.71	68.26	12,335.20	0.04%	2.64%	0.00%	9.00%	0.00%
Loews Corp	L	253.68	57.76	14,652.79	0.05%	0.43%	0.00%	12.50%	0.01%
Lowe's Cos Inc	LOW	673.75	258.48	174,150.12	0.54%	1.24%	0.01%	16.50%	0.09%
IDEX Corp	IEX	76.03	236.32	17,967.65	0.06%	0.91%	0.00%	8.00%	0.00%
Marsh & McLennan Cos Inc	MMC	504.90	173.82	87,760.85	0.27%	1.23%	0.00%	12.00%	0.03%
Masco Corp	MAS	244.09	70.22	17,139.79	0.05%	1.34%	0.00%	10.00%	0.01%
S&P Global Inc	SPGI	241.00	471.93	113,735.13	0.35%	0.65%	0.00%	10.50%	0.04%
Medtronic PLC	MDT	1,344.56	103.45	139,094.53	0.43%	2.44%	0.01%	9.00%	0.04%
Viatris Inc	VTRS	1,209.39	13.53	16,363.09		3.25%			
CVS Health Corp	CVS	1,320.06	103.16	136,177.29	0.42%	2.13%	0.01%	6.00%	0.03%
DuPont de Nemours Inc	DD	518.10	80.78	41,852.44		1.49%			
Micron Technology Inc	MU	1,120.17	93.15	104,343.84		0.43%		22.50%	

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[4] Shares Outst'g	[5] Price	[6] Market Capitalization	[7] Weight in Index	[8] Estimated Dividend Yield	[9] Cap-Weighted Dividend Yield	[10] Value Line Long-Term Growth Est.	[11] Cap-Weighted Long-Term Growth Est.
Motorola Solutions Inc	MSI	168.90	271.70	45,889.31	0.14%	1.16%	0.00%	7.00%	0.01%
Cboe Global Markets Inc	CBOE	106.64	130.40	13,906.25	0.04%	1.47%	0.00%	12.00%	0.01%
Laboratory Corp of America Holdings	LH	95.70	314.21	30,069.90	0.09%	n/a		6.00%	0.01%
Newmont Corp	NEM	797.44	62.02	49,456.92	0.15%	3.55%	0.01%	12.00%	0.02%
NIKE Inc	NKE	1,277.81	166.67	212,971.93		0.73%		27.00%	
NiSource Inc	NI	392.71	27.61	10,842.59	0.03%	3.19%	0.00%	8.50%	0.00%
Norfolk Southern Corp	NSC	243.35	297.71	72,446.24	0.23%	1.46%	0.00%	10.50%	0.02%
Principal Financial Group Inc	PFG	265.07	72.33	19,172.44	0.06%	3.54%	0.00%	6.00%	0.00%
Eversource Energy	ES	344.27	90.98	31,321.59	0.10%	2.65%	0.00%	6.50%	0.01%
Northrop Grumman Corp	NOC	158.54	387.07	61,365.30	0.19%	1.62%	0.00%	8.50%	0.02%
Wells Fargo & Co	WFC	3,987.23	47.98	191,307.44	0.59%	1.67%	0.01%	5.50%	0.03%
Nucor Corp	NUE	285.80	114.15	32,623.96	0.10%	1.75%	0.00%	12.00%	0.01%
PVH Corp	PVH	69.98	106.65	7,463.15	0.02%	0.14%	0.00%	13.50%	0.00%
Occidental Petroleum Corp	OXY	933.98	28.99	27,076.11		0.14%		36.50%	
Omnicom Group Inc	OMC	212.56	73.27	15,574.20	0.05%	3.82%	0.00%	6.00%	0.00%
ONEOK Inc	OKE	445.94	58.76	26,203.26	0.08%	6.36%	0.01%	10.00%	0.01%
Raymond James Financial Inc	RJF	239.16	100.40	24,011.66	0.07%	1.35%	0.00%	10.50%	0.01%
Parker-Hannifin Corp	PH	128.52	318.12	40,883.19	0.13%	1.30%	0.00%	13.50%	0.02%
Rollins Inc	ROL	492.05	34.21	16,833.00	0.05%	1.17%	0.00%	11.50%	0.01%
PPL Corp	PPL	750.72	30.06	22,566.52		5.52%		-6.00%	
ConocoPhillips	COP	1,318.95	72.18	95,201.59	0.30%	1.11%	0.00%	13.50%	0.04%
PulteGroup Inc	PHM	253.19	57.16	14,472.11	0.05%	1.05%	0.00%	13.00%	0.01%
Pinnacle West Capital Corp	PNW	112.82	70.59	7,963.89		4.82%		0.00%	
PNC Financial Services Group Inc/The	PNC	422.64	200.52	84,747.97	0.26%	2.49%	0.01%	11.50%	0.03%
PPG Industries Inc	PPG	237.40	172.44	40,937.43	0.13%	1.37%	0.00%	3.00%	0.00%
Progressive Corp/The	PGR	584.40	102.65	59,988.66	0.19%	0.39%	0.00%	5.00%	0.01%
Public Service Enterprise Group Inc	PEG	505.66	66.73	33,742.96	0.10%	3.06%	0.00%	3.50%	0.00%
Robert Half International Inc	RHI	111.33	111.52	12,415.52	0.04%	1.36%	0.00%	7.50%	0.00%
Edison International	EIX	379.91	68.25	25,928.72		4.10%			
Schlumberger NV	SLB	1,402.63	29.95	42,008.86	0.13%	1.67%	0.00%	8.50%	0.01%
Charles Schwab Corp/The	SCHW	1,811.31	84.10	152,330.83	0.47%	0.86%	0.00%	7.00%	0.03%
Sherwin-Williams Co/The	SHW	262.20	352.16	92,334.94	0.29%	0.62%	0.00%	10.50%	0.03%
West Pharmaceutical Services Inc	WST	74.08	469.01	34,744.26	0.11%	0.15%	0.00%	17.00%	0.02%
J M Smucker Co/The	SJM	108.36	135.82	14,717.86	0.05%	2.92%	0.00%	4.00%	0.00%
Snap-on Inc	SNA	53.54	215.38	11,530.37	0.04%	2.64%	0.00%	4.50%	0.00%
AMETEK Inc	AME	231.33	147.04	34,014.03	0.11%	0.54%	0.00%	9.00%	0.01%
Southern Co/The	SO	1,059.80	68.58	72,681.36	0.23%	3.85%	0.01%	6.00%	0.01%
Truist Financial Corp	TFC	1,334.89	58.55	78,157.93	0.24%	3.28%	0.01%	7.00%	0.02%
Southwest Airlines Co	LUV	591.92	42.84	25,357.85		n/a		34.00%	
W R Berkley Corp	WRB	176.64	82.39	14,553.37	0.05%	0.63%	0.00%	14.50%	0.01%
Stanley Black & Decker Inc	SWK	163.03	188.62	30,751.28	0.10%	1.68%	0.00%	6.00%	0.01%
Public Storage	PSA	175.36	374.56	65,680.97	0.20%	2.14%	0.00%	6.50%	0.01%
Arista Networks Inc	ANET	307.28	143.75	44,172.08	0.14%	n/a		4.50%	0.01%
Sysco Corp	SYY	512.66	78.55	40,269.13	0.13%	2.39%	0.00%	17.00%	0.02%
Corteva Inc	CTVA	730.27	47.28	34,527.02		1.18%			
Texas Instruments Inc	TXN	923.53	188.47	174,056.95	0.54%	2.44%	0.01%	9.00%	0.05%
Textron Inc	TXT	220.43	77.20	17,016.81	0.05%	0.10%	0.00%	8.50%	0.00%
Thermo Fisher Scientific Inc	TMO	394.05	667.24	262,924.59	0.82%	0.16%	0.00%	15.00%	0.12%
TJX Cos Inc/The	TJX	1,192.88	75.92	90,563.30	0.28%	1.37%	0.00%	20.00%	0.06%
Globe Life Inc	GL	100.98	93.72	9,463.75	0.03%	0.84%	0.00%	8.00%	0.00%
Johnson Controls International plc	JCI	704.33	81.31	57,269.23	0.18%	1.67%	0.00%	14.00%	0.02%
Ulta Beauty Inc	ULTA	54.12	412.34	22,315.84	0.07%	n/a		15.50%	0.01%
Union Pacific Corp	UNP	642.88	251.93	161,959.75	0.50%	1.87%	0.01%	10.00%	0.05%
Keysight Technologies Inc	KEYS	183.04	206.51	37,800.00	0.12%	n/a		17.00%	0.02%
UnitedHealth Group Inc	UNH	941.85	502.14	472,941.06	1.47%	1.16%	0.02%	12.00%	0.18%
Marathon Oil Corp	MRO	778.54	16.42	12,783.58		1.46%			
Bio-Rad Laboratories Inc	BIO	24.84	755.57	18,765.34	0.06%	n/a		11.50%	0.01%
Ventas Inc	VTR	399.18	51.12	20,405.88	0.06%	3.52%	0.00%	4.50%	0.00%
VF Corp	VFC	392.78	73.22	28,759.50	0.09%	2.73%	0.00%	9.50%	0.01%
Vornado Realty Trust	VNO	191.68	41.86	8,023.77		5.06%		-22.50%	
Vulcan Materials Co	VMC	132.71	207.58	27,546.90	0.09%	0.71%	0.00%	10.00%	0.01%
Weyerhaeuser Co	WY	749.05	41.18	30,845.67		1.65%		22.00%	
Whirlpool Corp	WHR	60.74	234.66	14,253.95	0.04%	2.39%	0.00%	9.50%	0.00%
Williams Cos Inc/The	WMB	1,215.03	26.04	31,639.38	0.10%	6.30%	0.01%	10.50%	0.01%
WEC Energy Group Inc	WEC	315.44	97.07	30,619.28	0.10%	3.00%	0.00%	6.50%	0.01%
Adobe Inc	ADBE	475.80	567.06	269,807.15	0.84%	n/a		15.50%	0.13%
AES Corp/The	AES	666.71	24.30	16,201.15		2.60%		24.00%	
Amgen Inc	AMGN	563.27	224.97	126,717.95	0.39%	3.45%	0.01%	5.50%	0.02%
Apple Inc	AAPL	16,406.40	177.57	2,913,283.92	9.06%	0.50%	0.04%	13.00%	1.18%
Autodesk Inc	ADSK	219.97	281.19	61,854.21	0.19%	n/a		18.00%	0.03%
Cintas Corp	CTAS	103.66	443.17	45,940.77	0.14%	0.86%	0.00%	13.50%	0.02%
Comcast Corp	CMCSA	4,559.48	50.33	229,478.58	0.71%	1.99%	0.01%	11.00%	0.08%
Molson Coors Beverage Co	TAP	200.59	46.35	9,297.11		2.93%		41.00%	
KLA Corp	KLAC	151.62	430.11	65,214.14	0.20%	0.98%	0.00%	19.50%	0.04%
Marriott International Inc/MD	MAR	325.68	165.24	53,815.86	0.17%	n/a		17.50%	0.03%
McCormick & Co Inc/MD	MKC	249.35	96.61	24,089.90	0.07%	1.53%	0.00%	6.00%	0.00%
PACCAR Inc	PCAR	347.18	88.26	30,641.84	0.10%	1.54%	0.00%	5.00%	0.00%
Costco Wholesale Corp	COST	443.43	567.70	251,736.35	0.78%	0.56%	0.00%	10.50%	0.08%
First Republic Bank/CA	FRC	179.06	206.51	36,977.68	0.11%	0.43%	0.00%	13.50%	0.02%
Stryker Corp	SYK	377.24	267.42	100,881.52	0.31%	1.04%	0.00%	11.00%	0.03%
Tyson Foods Inc	TSN	293.07	87.16	25,544.07	0.08%	2.11%	0.00%	6.00%	0.00%
Lamb Weston Holdings Inc	LW	146.07	63.38	9,257.79	0.03%	1.55%	0.00%	6.00%	0.00%
Applied Materials Inc	AMAT	888.51	157.36	139,816.41	0.43%	0.61%	0.00%	16.50%	0.07%
American Airlines Group Inc	AAL	647.52	17.96	11,629.37		n/a			
Cardinal Health Inc	CAH	281.79	51.49	14,509.26	0.05%	3.81%	0.00%	12.00%	0.01%
Cerner Corp	CERN	292.21	92.87	27,137.64	0.08%	1.16%	0.00%	11.00%	0.01%
Cincinnati Financial Corp	CINF	161.14	113.93	18,358.79	0.06%	2.21%	0.00%	17.50%	0.01%
ViacomCBS Inc	VIAC	606.71	30.18	18,310.39	0.06%	3.18%	0.00%	7.00%	0.00%
DR Horton Inc	DHI	356.18	108.45	38,627.83	0.12%	0.83%	0.00%	11.00%	0.01%
Electronic Arts Inc	EA	282.81	131.90	37,302.38	0.12%	0.52%	0.00%	12.50%	0.01%

STANDARD AND POOR'S 500 INDEX

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Expeditors International of Washington Inc	EXPD	169.40	134.29	22,749.26	0.07%	0.86%	0.00%	10.00%	0.01%
Fastenal Co	FAST	575.16	64.06	36,844.94	0.11%	1.75%	0.00%	9.00%	0.01%
M&T Bank Corp	MTB	128.69	153.58	19,763.44	0.06%	3.13%	0.00%	8.00%	0.00%
Xcel Energy Inc	XEL	538.68	67.70	36,468.37	0.11%	2.70%	0.00%	6.00%	0.01%
Fiserv Inc	FISV	660.23	103.79	68,525.48	0.21%	n/a		13.00%	0.03%
Fifth Third Bancorp	FITB	683.76	43.55	29,777.62	0.09%	2.76%	0.00%	9.50%	0.01%
Gilead Sciences Inc	GILD	1,254.38	72.61	91,080.82	0.28%	3.91%	0.01%	3.50%	0.01%
Hasbro Inc	HAS	137.95	101.78	14,040.25	0.04%	2.67%	0.00%	11.50%	0.01%
Huntington Bancshares Inc/OH	HBAN	1,446.46	15.42	22,304.43	0.07%	4.02%	0.00%	9.00%	0.01%
Welltower Inc	WELL	435.28	85.77	37,333.54		2.84%		-1.50%	
Biogen Inc	BIIB	146.89	239.92	35,242.57	0.11%	n/a		7.00%	0.01%
Northern Trust Corp	NTRS	207.66	119.61	24,838.33	0.08%	2.34%	0.00%	7.00%	0.01%
Packaging Corp of America	PKG	94.99	136.15	12,933.02	0.04%	2.94%	0.00%	9.00%	0.00%
Paychex Inc	PAYX	360.76	136.50	49,243.33	0.15%	1.93%	0.00%	8.00%	0.01%
People's United Financial Inc	PBCT	428.03	17.82	7,627.41	0.02%	4.10%	0.00%	2.50%	0.00%
QUALCOMM Inc	QCOM	1,120.00	182.87	204,814.40	0.64%	1.49%	0.01%	18.50%	0.12%
Roper Technologies Inc	ROP	105.49	491.86	51,883.85	0.16%	0.50%	0.00%	8.50%	0.01%
Ross Stores Inc	ROST	353.33	114.28	40,378.55	0.13%	1.00%	0.00%	14.00%	0.02%
IDEXX Laboratories Inc	IDXX	84.79	658.46	55,833.46	0.17%	n/a		14.50%	0.03%
Starbucks Corp	SBUX	1,173.20	116.97	137,229.20	0.43%	1.68%	0.01%	16.00%	0.07%
KeyCorp	KEY	931.06	23.13	21,535.37	0.07%	3.37%	0.00%	9.50%	0.01%
Fox Corp	FOXA	320.35	36.90	11,820.80	0.04%	1.30%	0.00%	10.50%	0.00%
Fox Corp	FOX	249.24	34.27	8,541.45		1.40%			
State Street Corp	STT	365.63	93.00	34,003.50	0.11%	2.45%	0.00%	7.50%	0.01%
Norwegian Cruise Line Holdings Ltd	NCLH	416.89	20.74	8,646.32		n/a			
US Bancorp	USB	1,482.80	56.17	83,288.76	0.26%	3.28%	0.01%	6.50%	0.02%
A O Smith Corp	AOS	133.19	85.85	11,434.10	0.04%	1.30%	0.00%	10.00%	0.00%
NortonLifeLock Inc	NLOK	581.86	25.98	15,116.67	0.05%	1.92%	0.00%	11.00%	0.01%
T Rowe Price Group Inc	TROW	224.75	196.64	44,195.04	0.14%	2.20%	0.00%	12.00%	0.02%
Waste Management Inc	WM	418.32	166.90	69,816.94	0.22%	1.38%	0.00%	7.50%	0.02%
Constellation Brands Inc	STZ	164.26	250.97	41,225.34	0.13%	1.21%	0.00%	7.00%	0.01%
Xilinx Inc	XLNX	247.88	212.03	52,558.00	0.16%	0.70%	0.00%	8.50%	0.01%
DENTSPLY SIRONA Inc	XRAY	218.61	55.79	12,196.08	0.04%	0.79%	0.00%	5.50%	0.00%
Zions Bancorp NA	ZION	156.46	63.16	9,882.20	0.03%	2.41%	0.00%	7.50%	0.00%
Alaska Air Group Inc	ALK	125.31	52.10	6,528.70		n/a		78.00%	
Invesco Ltd	IVZ	461.21	23.02	10,616.99	0.03%	2.95%	0.00%	15.50%	0.01%
Linde PLC	LIN	511.29	346.43	177,124.81		1.22%			
Intuit Inc	INTU	283.17	643.22	182,138.68	0.57%	0.42%	0.00%	15.00%	0.08%
Morgan Stanley	MS	1,794.41	98.16	176,139.48	0.55%	2.85%	0.02%	10.50%	0.06%
Microchip Technology Inc	MCHP	554.87	87.06	48,307.07	0.15%	1.07%	0.00%	10.50%	0.02%
Chubb Ltd	CB	430.74	193.31	83,266.54	0.26%	1.66%	0.00%	12.50%	0.03%
Hologic Inc	HOLX	251.42	76.56	19,248.79		n/a		25.00%	
Citizens Financial Group Inc	CFG	426.20	47.25	20,137.95	0.06%	3.30%	0.00%	8.50%	0.01%
O'Reilly Automotive Inc	ORLY	67.38	706.23	47,584.36	0.15%	n/a		13.00%	0.02%
Allstate Corp/The	ALL	286.68	117.65	33,727.43	0.10%	2.75%	0.00%	5.00%	0.01%
Equity Residential	EQR	375.02	90.50	33,938.95	0.11%	2.66%	0.00%	2.00%	0.00%
BorgWarner Inc	BWA	239.77	45.07	10,806.48	0.03%	1.51%	0.00%	8.00%	0.00%
Organon & Co	OGN	253.55	30.45	7,720.60		3.68%			
Host Hotels & Resorts Inc	HST	714.04	17.39	12,417.07	0.04%	n/a		10.00%	0.00%
Incyte Corp	INCY	220.89	73.40	16,213.40		n/a		58.50%	
Simon Property Group Inc	SPG	328.61	159.77	52,502.18	0.16%	4.13%	0.01%	1.50%	0.00%
Eastman Chemical Co	EMN	134.44	120.91	16,255.14	0.05%	2.51%	0.00%	10.50%	0.01%
Twitter Inc	TWTR	799.61	43.22	34,559.14		n/a		39.00%	
AvalonBay Communities Inc	AVB	139.74	252.59	35,297.18	0.11%	2.52%	0.00%	1.50%	0.00%
Prudential Financial Inc	PRU	378.00	108.24	40,914.72	0.13%	4.25%	0.01%	4.50%	0.01%
United Parcel Service Inc	UPS	729.16	214.34	156,287.73	0.49%	1.90%	0.01%	11.50%	0.06%
Walgreens Boots Alliance Inc	WBA	863.95	52.16	45,063.37	0.14%	3.66%	0.01%	7.50%	0.01%
STERIS PLC	STE	100.02	243.41	24,346.60	0.08%	0.71%	0.00%	12.00%	0.01%
McKesson Corp	MCK	152.68	248.57	37,952.16	0.12%	0.76%	0.00%	9.50%	0.01%
Lockheed Martin Corp	LMT	275.79	355.41	98,017.10	0.30%	3.15%	0.01%	7.50%	0.02%
AmerisourceBergen Corp	ABC	208.13	132.89	27,658.79	0.09%	1.38%	0.00%	6.50%	0.01%
Capital One Financial Corp	COF	425.62	145.09	61,753.50		1.65%			
Waters Corp	WAT	61.04	372.60	22,742.01	0.07%	n/a		6.00%	0.00%
Dollar Tree Inc	DLTR	224.96	140.52	31,610.82	0.10%	n/a		8.50%	0.01%
Darden Restaurants Inc	DRI	129.79	150.64	19,550.81	0.06%	2.92%	0.00%	19.50%	0.01%
Match Group Inc	MTCH	283.09	132.25	37,437.99	0.12%	n/a		18.50%	0.02%
Domino's Pizza Inc	DPZ	36.39	564.33	20,534.28	0.06%	0.67%	0.00%	15.00%	0.01%
NVR Inc	NVR	3.48	5,908.87	20,580.59	0.06%	n/a		9.00%	0.01%
NetApp Inc	NTAP	222.28	91.99	20,447.35	0.06%	2.17%	0.00%	8.00%	0.01%
Citrix Systems Inc	CTXS	124.72	94.59	11,797.55	0.04%	1.56%	0.00%	8.00%	0.00%
DXC Technology Co	DXC	252.24	32.19	8,119.57	0.03%	n/a		6.50%	0.00%
Old Dominion Freight Line Inc	ODFL	115.01	358.38	41,217.64	0.13%	0.22%	0.00%	11.50%	0.01%
DaVita Inc	DVA	101.90	113.76	11,592.14	0.04%	n/a		16.00%	0.01%
Hartford Financial Services Group Inc/The	HIG	340.35	69.04	23,497.97	0.07%	2.23%	0.00%	6.50%	0.00%
Iron Mountain Inc	IRM	289.55	52.33	15,152.10	0.05%	4.73%	0.00%	8.50%	0.00%
Estee Lauder Cos Inc/The	EL	231.71	370.20	85,777.19	0.27%	0.65%	0.00%	11.50%	0.03%
Cadence Design Systems Inc	CDNS	277.14	186.35	51,645.23	0.16%	n/a		12.00%	0.02%
Tyler Technologies Inc	TYL	40.98	537.95	22,043.04	0.07%	n/a		14.00%	0.01%
Universal Health Services Inc	UHS	73.12	129.66	9,480.74	0.03%	0.62%	0.00%	11.00%	0.00%
Skyworks Solutions Inc	SWKS	165.39	155.14	25,658.14	0.08%	1.44%	0.00%	16.00%	0.01%
Quest Diagnostics Inc	DGX	122.68	173.01	21,224.00	0.07%	1.43%	0.00%	7.50%	0.00%
Activision Blizzard Inc	ATVI	778.89	66.53	51,819.49	0.16%	0.71%	0.00%	13.00%	0.02%
Rockwell Automation Inc	ROK	116.01	348.85	40,471.14	0.13%	1.28%	0.00%	10.00%	0.01%
Kraft Heinz Co/The	KHC	1,224.04	35.90	43,943.11	0.14%	4.46%	0.01%	1.50%	0.00%
American Tower Corp	AMT	455.41	292.50	133,208.60	0.41%	1.90%	0.01%	9.50%	0.04%
Regeneron Pharmaceuticals Inc	REGN	105.72	631.52	66,764.29	0.21%	n/a		12.50%	0.03%
Amazon.com Inc	AMZN	507.15	3,334.34	1,691,003.86		n/a		30.00%	
Jack Henry & Associates Inc	JKHY	74.04	166.99	12,364.11	0.04%	1.10%	0.00%	10.50%	0.00%
Ralph Lauren Corp	RL	48.74	118.86	5,792.76	0.02%	2.31%	0.00%	11.50%	0.00%
Boston Properties Inc	BXP	156.21	115.18	17,991.92		3.40%		-2.00%	

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[4] Shares Outst'g	[5] Price	[6] Market Capitalization	[7] Weight in Index	[8] Estimated Dividend Yield	[9] Cap-Weighted Dividend Yield	[10] Value Line Long-Term Growth Est.	[11] Cap-Weighted Long-Term Growth Est.
Amphenol Corp	APH	598.03	87.46	52,303.53	0.16%	0.91%	0.00%	12.00%	0.02%
Howmet Aerospace Inc	HWM	427.22	31.83	13,598.35	0.04%	0.25%	0.00%	12.00%	0.01%
Pioneer Natural Resources Co	PXD	244.13	181.88	44,403.09	0.14%	1.36%	0.00%	20.00%	0.03%
Valero Energy Corp	VLO	408.84	75.11	30,707.67	0.10%	5.22%	0.00%	13.00%	0.01%
Synopsys Inc	SNPS	153.44	368.50	56,541.90	0.18%	n/a		13.00%	0.02%
Etsy Inc	ETSY	126.78	218.94	27,757.43		n/a		29.00%	
CH Robinson Worldwide Inc	CHRW	129.99	107.63	13,990.50	0.04%	2.04%	0.00%	9.00%	0.00%
Accenture PLC	ACN	658.33	414.55	272,911.95	0.85%	0.94%	0.01%	10.00%	0.08%
TransDigm Group Inc	TDG	55.25	636.28	35,153.83	0.11%	n/a		16.50%	0.02%
Yum! Brands Inc	YUM	293.13	138.86	40,704.45	0.13%	1.44%	0.00%	11.00%	0.01%
Prologis Inc	PLD	739.75	168.36	124,543.47	0.39%	1.50%	0.01%	8.50%	0.03%
FirstEnergy Corp	FE	544.42	41.59	22,642.43	0.07%	3.75%	0.00%	11.50%	0.01%
VeriSign Inc	VRSN	111.08	253.82	28,193.82	0.09%	n/a		8.50%	0.01%
Quanta Services Inc	PWR	142.50	114.66	16,338.94	0.05%	0.24%	0.00%	12.50%	0.01%
Henry Schein Inc	HSIC	138.67	77.53	10,751.40	0.03%	n/a		6.50%	0.00%
Ameren Corp	AEE	255.41	89.01	22,734.04	0.07%	2.47%	0.00%	6.50%	0.00%
ANSYS Inc	ANSS	87.25	401.12	34,998.92	0.11%	n/a		8.00%	0.01%
FactSet Research Systems Inc	FDS	37.64	486.01	18,294.39	0.06%	0.67%	0.00%	9.50%	0.01%
NVIDIA Corp	NVDA	2,500.00	294.11	735,275.00	2.29%	0.05%	0.00%	20.00%	0.46%
Sealed Air Corp	SEE	148.16	67.47	9,996.15	0.03%	1.19%	0.00%	13.50%	0.00%
Cognizant Technology Solutions Corp	CTSH	525.25	88.72	46,600.36	0.14%	1.08%	0.00%	7.00%	0.01%
SVB Financial Group	SIVB	58.69	678.24	39,803.87	0.12%	n/a		5.00%	0.01%
Intuitive Surgical Inc	ISRG	357.24	359.30	128,355.25	0.40%	n/a		16.00%	0.06%
Take-Two Interactive Software Inc	TTWO	115.30	177.72	20,491.12	0.06%	n/a		12.00%	0.01%
Republic Services Inc	RSG	317.10	139.45	44,218.90	0.14%	1.32%	0.00%	11.00%	0.02%
eBay Inc	EBAY	626.00	66.50	41,629.27	0.13%	1.08%	0.00%	16.50%	0.02%
Goldman Sachs Group Inc/The	GS	334.79	382.55	128,075.06	0.40%	2.09%	0.01%	8.50%	0.03%
SBA Communications Corp	SBAC	108.78	389.02	42,317.98		0.60%		45.00%	
Sempra Energy	SRE	315.07	132.28	41,677.59	0.13%	3.33%	0.00%	10.00%	0.01%
Moody's Corp	MCO	185.90	390.58	72,608.82	0.23%	0.63%	0.00%	10.00%	0.02%
Booking Holdings Inc	BKNG	41.06	2,399.23	98,519.58	0.31%	n/a		14.00%	0.04%
F5 Inc	FFIV	61.23	244.71	14,983.35	0.05%	n/a		7.00%	0.00%
Akamai Technologies Inc	AKAM	162.48	117.04	19,016.66	0.06%	n/a		9.50%	0.01%
Charles River Laboratories International Inc	CRL	50.46	376.78	19,013.83	0.06%	n/a		7.00%	0.00%
MarketAxess Holdings Inc	MKTX	38.03	411.27	15,638.95	0.05%	0.64%	0.00%	14.00%	0.01%
Devon Energy Corp	DVN	677.00	44.05	29,821.85		7.63%		29.50%	
Alphabet Inc	GOOGL	300.81	2,897.04	871,458.60		n/a			
Bio-Techne Corp	TECH	39.30	517.34	20,328.88	0.06%	0.25%	0.00%	13.00%	0.01%
Teleflex Inc	TFX	46.85	328.48	15,387.65	0.05%	0.41%	0.00%	15.00%	0.01%
Netflix Inc	NFLX	442.95	602.44	266,852.00		n/a		23.50%	
Allegion plc	ALLE	89.70	132.44	11,879.34	0.04%	1.09%	0.00%	9.50%	0.00%
Agilent Technologies Inc	A	302.00	159.65	48,214.46	0.15%	0.53%	0.00%	12.50%	0.02%
Anthem Inc	ANTM	242.72	463.54	112,508.11	0.35%	0.98%	0.00%	13.00%	0.05%
Trimble Inc	TRMB	251.01	87.19	21,885.39	0.07%	n/a		14.50%	0.01%
CME Group Inc	CME	359.40	228.46	82,107.61	0.26%	1.58%	0.00%	8.50%	0.02%
Juniper Networks Inc	JNPR	325.18	35.71	11,612.21	0.04%	2.24%	0.00%	7.00%	0.00%
BlackRock Inc	BLK	151.92	915.56	139,089.13	0.43%	1.80%	0.01%	11.00%	0.05%
DTE Energy Co	DTE	193.75	119.54	23,161.11	0.07%	2.96%	0.00%	1.00%	0.00%
Nasdaq Inc	NDAQ	167.22	210.01	35,118.29	0.11%	1.03%	0.00%	6.50%	0.01%
Celanese Corp	CE	108.87	168.06	18,296.86	0.06%	1.62%	0.00%	6.50%	0.00%
Philip Morris International Inc	PM	1,556.83	95.00	147,898.66	0.46%	5.26%	0.02%	7.00%	0.03%
salesforce.com Inc	CRM	985.00	254.13	250,318.05	0.78%	n/a		20.00%	0.16%
Ingersoll Rand Inc	IR	407.59	61.87	25,217.28		0.13%			
Huntington Ingalls Industries Inc	HII	40.06	186.74	7,480.99	0.02%	2.53%	0.00%	7.00%	0.00%
MetLife Inc	MET	841.16	62.49	52,564.09	0.16%	3.07%	0.01%	6.50%	0.01%
Under Armour Inc	UA	253.02	18.04	4,564.46		n/a			
Tapestry Inc	TPR	275.14	40.60	11,170.81	0.03%	2.46%	0.00%	10.00%	0.00%
CSX Corp	CSX	2,217.98	37.60	83,396.16	0.26%	0.99%	0.00%	11.50%	0.03%
Edwards Lifesciences Corp	EW	624.33	129.55	80,882.47	0.25%	n/a		13.00%	0.03%
Ameriprise Financial Inc	AMP	111.89	301.66	33,752.74	0.10%	1.50%	0.00%	13.50%	0.01%
Zebra Technologies Corp	ZBRA	53.44	595.20	31,808.08	0.10%	n/a		13.00%	0.01%
Zimmer Biomet Holdings Inc	ZBH	208.91	127.04	26,539.67	0.08%	0.76%	0.00%	8.50%	0.01%
CBRE Group Inc	CBRE	334.67	108.51	36,314.61	0.11%	n/a		10.50%	0.01%
Mastercard Inc	MA	974.71	359.32	350,232.44	1.09%	0.55%	0.01%	13.00%	0.14%
CarMax Inc	KMX	161.87	130.23	21,080.59	0.07%	n/a		12.50%	0.01%
Intercontinental Exchange Inc	ICE	563.40	136.77	77,056.77	0.24%	0.97%	0.00%	8.00%	0.02%
Fidelity National Information Services Inc	FIS	608.94	109.15	66,465.47		1.43%		28.00%	
Chipotle Mexican Grill Inc	CMG	28.14	1,748.25	49,187.01		n/a		22.00%	
Wynn Resorts Ltd	WYNN	115.66	85.04	9,835.56		n/a		27.00%	
Live Nation Entertainment Inc	LYV	224.66	119.69	26,889.56		n/a			
Assurant Inc	AIZ	56.98	155.86	8,880.44	0.03%	1.75%	0.00%	15.50%	0.00%
NRG Energy Inc	NRG	244.84	43.08	10,547.66		3.02%		-1.50%	
Regions Financial Corp	RF	953.28	21.80	20,781.57	0.06%	3.12%	0.00%	9.50%	0.01%
Monster Beverage Corp	MNST	529.14	96.04	50,818.51	0.16%	n/a		11.50%	0.02%
Mosaic Co/The	MOS	370.41	39.29	14,553.41		1.15%		56.50%	
Baker Hughes Co	BKR	871.08	24.06	20,958.18		2.99%			
Expedia Group Inc	EXPE	146.00	180.72	26,385.84		n/a			
Evergy Inc	EVRG	226.99	68.61	15,573.99	0.05%	3.34%	0.00%	8.00%	0.00%
Discovery Inc	DISCA	169.21	23.54	3,983.13	0.01%	n/a		13.50%	0.00%
CF Industries Holdings Inc	CF	214.48	70.78	15,180.54	0.05%	1.70%	0.00%	19.50%	0.01%
Leidos Holdings Inc	LDOS	140.34	88.90	12,476.14	0.04%	1.62%	0.00%	9.00%	0.00%
APA Corp	APA	363.27	26.89	9,768.44		1.86%			
Alphabet Inc	GOOG	317.74	2,893.59	919,403.50		n/a		23.50%	
TE Connectivity Ltd	TEL	326.31	161.34	52,647.34	0.16%	1.39%	0.00%	10.00%	0.02%
Cooper Cos Inc/The	COO	49.41	418.94	20,698.99	0.06%	0.01%	0.00%	19.00%	0.01%
Discover Financial Services	DFS	293.08	115.56	33,867.86	0.11%	1.73%	0.00%	16.00%	0.02%
Visa Inc	V	1,667.42	216.71	361,345.72	1.12%	0.69%	0.01%	12.00%	0.13%
Mid-America Apartment Communities Inc	MAA	115.14	229.44	26,417.26	0.08%	1.90%	0.00%	9.00%	0.01%
Xylem Inc/NY	XYL	180.33	119.92	21,624.57	0.07%	0.93%	0.00%	6.50%	0.00%
Marathon Petroleum Corp	MPC	615.59	63.99	39,391.48		3.63%			

STANDARD AND POOR'S 500 INDEX

		[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Name	Ticker	Shares Outst'g	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Value Line Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
Tractor Supply Co	TSCO	113.82	238.60	27,156.26	0.08%	0.87%	0.00%	11.00%	0.01%
Advanced Micro Devices Inc	AMD	1,207.61	143.90	173,775.08		n/a		30.00%	
ResMed Inc	RMD	145.72	260.48	37,957.93	0.12%	0.64%	0.00%	8.50%	0.01%
Mettler-Toledo International Inc	MTD	22.99	1,697.21	39,012.07	0.12%	n/a		12.50%	0.02%
Copart Inc	CPRT	237.19	151.62	35,962.44	0.11%	n/a		12.00%	0.01%
Albemarle Corp	ALB	116.98	233.77	27,345.48	0.09%	0.67%	0.00%	6.50%	0.01%
Fortinet Inc	FTNT	163.50	359.40	58,761.90		n/a		21.00%	
Moderna Inc	MRNA	405.45	253.98	102,976.19		n/a			
Essex Property Trust Inc	ESS	65.09	352.23	22,925.95		2.37%		-0.50%	
Realty Income Corp	O	565.81	71.59	40,506.55	0.13%	4.13%	0.01%	3.50%	0.00%
Westrock Co	WRK	263.09	44.36	11,670.58	0.04%	2.25%	0.00%	18.50%	0.01%
IHS Markit Ltd	INFO	398.84	132.92	53,013.95	0.16%	0.60%	0.00%	10.50%	0.02%
Westinghouse Air Brake Technologies Corp	WAB	186.82	92.11	17,208.08	0.05%	0.52%	0.00%	9.50%	0.01%
Pool Corp	POOL	40.09	566.00	22,689.81	0.07%	0.57%	0.00%	17.00%	0.01%
Western Digital Corp	WDC	311.62	65.21	20,320.94	0.06%	n/a		9.00%	0.01%
PepsiCo Inc	PEP	1,382.65	173.71	240,180.65	0.75%	2.48%	0.02%	6.50%	0.05%
Diamondback Energy Inc	FANG	181.18	107.85	19,539.72		1.85%			
ServiceNow Inc	NOW	199.00	649.11	129,172.89		n/a		44.50%	
Church & Dwight Co Inc	CHD	244.15	102.50	25,025.17	0.08%	0.99%	0.00%	8.00%	0.01%
Duke Realty Corp	DRE	380.85	65.64	24,998.99		1.71%		-2.00%	
Federal Realty Investment Trust	FRT	77.79	136.32	10,604.20	0.03%	3.14%	0.00%	2.00%	0.00%
MGM Resorts International	MGM	468.96	44.88	21,046.92		0.02%		25.00%	
American Electric Power Co Inc	AEP	503.65	88.97	44,809.92	0.14%	3.51%	0.00%	6.50%	0.01%
SolarEdge Technologies Inc	SEDG	52.52	280.57	14,735.54	0.05%	n/a		19.50%	0.01%
PTC Inc	PTC	117.87	121.15	14,280.19		n/a			
JB Hunt Transport Services Inc	JBHT	105.01	204.40	21,464.86	0.07%	0.59%	0.00%	10.00%	0.01%
Lam Research Corp	LRCX	140.80	719.15	101,255.60	0.31%	0.83%	0.00%	17.50%	0.06%
Mohawk Industries Inc	MHK	67.73	182.18	12,339.42	0.04%	n/a		10.50%	0.00%
Pentair PLC	PNR	165.48	73.03	12,084.86	0.04%	1.15%	0.00%	14.00%	0.01%
Vertex Pharmaceuticals Inc	VRTX	254.25	219.60	55,833.74	0.17%	n/a		18.50%	0.03%
Amcor PLC	AMCR	1,533.17	12.01	18,413.36	0.06%	4.00%	0.00%	15.00%	0.01%
Meta Platforms Inc	FB	2,366.28	336.35	795,897.61		n/a		21.50%	
T-Mobile US Inc	TMUS	1,249.05	115.98	144,865.28	0.45%	n/a		8.50%	0.04%
United Rentals Inc	URI	72.39	332.29	24,055.80	0.07%	n/a		12.50%	0.01%
ABIOMED Inc	ABMD	45.50	359.17	16,341.16	0.05%	n/a		9.50%	0.00%
Honeywell International Inc	HON	688.42	208.51	143,543.08	0.45%	1.88%	0.01%	11.00%	0.05%
Alexandria Real Estate Equities Inc	ARE	154.96	222.96	34,550.77	0.11%	2.06%	0.00%	12.00%	0.01%
Delta Air Lines Inc	DAL	640.01	39.08	25,011.75		n/a		49.00%	
Seagate Technology Holdings PLC	STX	222.64	112.98	25,153.42	0.08%	2.48%	0.00%	15.00%	0.01%
United Airlines Holdings Inc	UAL	323.61	43.78	14,167.69		n/a			
News Corp	NWS	199.63	22.50	4,491.68		0.89%			
Centene Corp	CNC	583.50	82.40	48,080.65	0.15%	n/a		9.50%	0.01%
Martin Marietta Materials Inc	MLM	62.38	440.52	27,480.52	0.09%	0.55%	0.00%	10.50%	0.01%
Teradyne Inc	TER	163.00	163.53	26,656.04	0.08%	0.24%	0.00%	13.50%	0.01%
PayPal Holdings Inc	PYPL	1,174.93	188.58	221,568.30	0.69%	n/a		16.00%	0.11%
Tesla Inc	TSLA	1,004.27	1,056.78	1,061,287.17		n/a			
DISH Network Corp	DISH	290.36	32.44	9,419.18	0.03%	n/a		4.00%	0.00%
Dow Inc	DOW	739.61	56.72	41,950.91		4.94%			
Penn National Gaming Inc	PENN	169.51	51.85	8,789.30		n/a		30.00%	
Everest Re Group Ltd	RE	39.37	273.92	10,783.96	0.03%	2.26%	0.00%	11.00%	0.00%
Teledyne Technologies Inc	TDY	46.66	436.89	20,383.10	0.06%	n/a		15.00%	0.01%
News Corp	NWSA	393.04	22.31	8,768.68		0.90%			
Exelon Corp	EXC	976.76	57.76	56,417.66	0.18%	2.65%	0.00%	5.50%	0.01%
Global Payments Inc	GPN	290.15	135.18	39,222.61	0.12%	0.74%	0.00%	16.50%	0.02%
Crown Castle International Corp	CCI	432.20	208.74	90,218.05	0.28%	2.82%	0.01%	8.50%	0.02%
Aptiv PLC	APTV	270.51	164.95	44,621.28		n/a		21.50%	
Advance Auto Parts Inc	AAP	62.36	239.88	14,957.72	0.05%	1.67%	0.00%	11.00%	0.01%
Align Technology Inc	ALGN	78.85	657.18	51,820.61	0.16%	n/a		17.00%	0.03%
Illumina Inc	ILMN	156.30	380.44	59,462.77	0.18%	n/a		10.00%	0.02%
LKQ Corp	LKQ	291.49	60.03	17,498.20	0.05%	1.67%	0.00%	14.00%	0.01%
Nielsen Holdings PLC	NLSN	358.93	20.51	7,361.59		1.17%			
Zoetis Inc	ZTS	473.13	244.03	115,456.94	0.36%	0.53%	0.00%	12.00%	0.04%
Equinix Inc	EQIX	90.04	845.84	76,160.28	0.24%	1.36%	0.00%	17.00%	0.04%
Digital Realty Trust Inc	DLR	283.79	176.87	50,193.41	0.16%	2.62%	0.00%	8.50%	0.01%
Las Vegas Sands Corp	LVS	763.99	37.64	28,756.58	0.09%	n/a		17.00%	0.02%
Discovery Inc	DISCK	330.15	22.90	7,560.34		n/a			

Notes:
[1] Equals sum of Col. [9]
[2] Equals sum of Col. [11]
[3] Equals ([1] x (1 + (0.5 x [2]))) + [2]
[4] Source: Bloomberg Professional as of December 31, 2021
[5] Source: Bloomberg Professional as of December 31, 2021
[6] Equals [4] x [5]
[7] Equals weight in S&P 500 based on market capitalization [6] if Growth Rate >0% and ≤20%
[8] Source: Bloomberg Professional, as of December 31, 2021
[9] Equals [7] x [8]
[10] Source: Value Line, as of December 31, 2021
[11] Equals [7] x [10]

Docket No. UE 399
Exhibit PAC/308
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Ann E. Bulkley

Risk Premium Approach

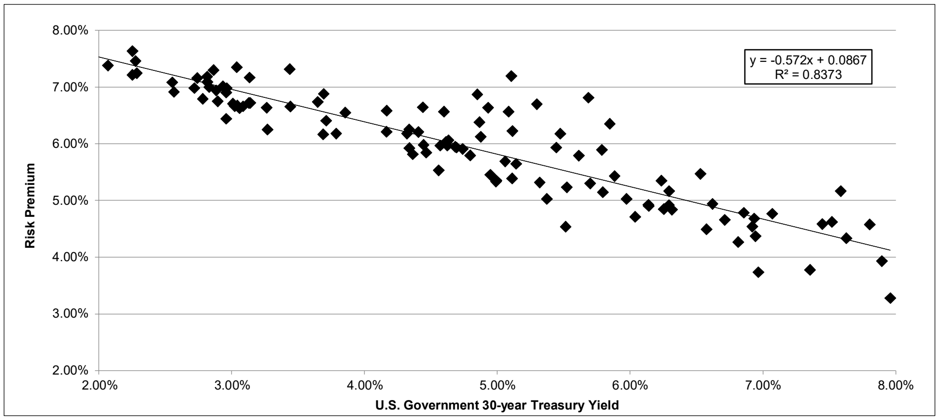
March 2022

Risk Premium -- Vertically Integrated Electric Utilities

	[1] Average Authorized VI Electric ROE	[2] U.S. Govt. 30-year Treasury	[3] Risk Premium
1992.1	12.38%	7.80%	4.58%
1992.2	11.83%	7.89%	3.93%
1992.3	12.03%	7.45%	4.59%
1992.4	12.14%	7.52%	4.62%
1993.1	11.84%	7.07%	4.77%
1993.2	11.64%	6.86%	4.79%
1993.3	11.15%	6.31%	4.84%
1993.4	11.04%	6.14%	4.90%
1994.1	11.07%	6.57%	4.49%
1994.2	11.13%	7.35%	3.78%
1994.3	12.75%	7.58%	5.17%
1994.4	11.24%	7.96%	3.28%
1995.1	11.96%	7.63%	4.34%
1995.2	11.32%	6.94%	4.37%
1995.3	11.37%	6.71%	4.66%
1995.4	11.58%	6.23%	5.35%
1996.1	11.46%	6.29%	5.17%
1996.2	11.46%	6.92%	4.54%
1996.3	10.70%	6.96%	3.74%
1996.4	11.56%	6.62%	4.94%
1997.1	11.08%	6.81%	4.27%
1997.2	11.62%	6.93%	4.68%
1997.3	12.00%	6.53%	5.47%
1997.4	11.06%	6.14%	4.92%
1998.1	11.31%	5.88%	5.43%
1998.2	12.20%	5.85%	6.35%
1998.3	11.65%	5.47%	6.18%
1998.4	12.30%	5.10%	7.20%
1999.1	10.40%	5.37%	5.03%
1999.2	10.94%	5.79%	5.15%
1999.3	10.75%	6.04%	4.71%
1999.4	11.10%	6.25%	4.85%
2000.1	11.21%	6.29%	4.92%
2000.2	11.00%	5.97%	5.03%
2000.3	11.68%	5.79%	5.89%
2000.4	12.50%	5.69%	6.81%
2001.1	11.38%	5.44%	5.93%
2001.2	11.00%	5.70%	5.30%
2001.3	10.76%	5.52%	5.23%
2001.4	11.99%	5.30%	6.70%
2002.1	10.05%	5.51%	4.54%
2002.2	11.41%	5.61%	5.79%
2002.3	11.65%	5.08%	6.57%
2002.4	11.57%	4.93%	6.64%
2003.1	11.72%	4.85%	6.87%
2003.2	11.16%	4.60%	6.56%
2003.3	10.50%	5.11%	5.39%
2003.4	11.34%	5.11%	6.23%
2004.1	11.00%	4.88%	6.12%
2004.2	10.64%	5.32%	5.32%
2004.3	10.75%	5.06%	5.69%
2004.4	11.24%	4.86%	6.38%
2005.1	10.63%	4.69%	5.93%
2005.2	10.31%	4.47%	5.85%
2005.3	11.08%	4.44%	6.65%
2005.4	10.63%	4.68%	5.95%
2006.1	10.70%	4.63%	6.06%
2006.2	10.79%	5.14%	5.65%
2006.3	10.35%	4.99%	5.35%
2006.4	10.65%	4.74%	5.91%
2007.1	10.59%	4.80%	5.80%
2007.2	10.33%	4.99%	5.34%
2007.3	10.40%	4.95%	5.45%
2007.4	10.65%	4.61%	6.04%
2008.1	10.62%	4.41%	6.21%
2008.2	10.54%	4.57%	5.97%
2008.3	10.43%	4.44%	5.98%
2008.4	10.39%	3.65%	6.74%
2009.1	10.75%	3.44%	7.31%
2009.2	10.75%	4.17%	6.58%
2009.3	10.50%	4.32%	6.18%
2009.4	10.59%	4.34%	6.26%
2010.1	10.59%	4.62%	5.97%
2010.2	10.18%	4.36%	5.82%
2010.3	10.40%	3.86%	6.55%
2010.4	10.38%	4.17%	6.21%
2011.1	10.09%	4.56%	5.53%
2011.2	10.26%	4.34%	5.92%
2011.3	10.57%	3.69%	6.88%
2011.4	10.39%	3.04%	7.35%
2012.1	10.30%	3.14%	7.17%
2012.2	9.95%	2.93%	7.02%
2012.3	9.90%	2.74%	7.16%

Risk Premium -- Vertically Integrated Electric Utilities

	[1]	[2]	[3]
	Average Authorized VI Electric ROE	U.S. Govt. 30-year Treasury	Risk Premium
2012.4	10.16%	2.86%	7.30%
2013.1	9.85%	3.13%	6.72%
2013.2	9.86%	3.14%	6.72%
2013.3	10.12%	3.71%	6.41%
2013.4	9.97%	3.79%	6.18%
2014.1	9.86%	3.69%	6.17%
2014.2	10.10%	3.44%	6.66%
2014.3	9.90%	3.26%	6.64%
2014.4	9.94%	2.96%	6.98%
2015.1	9.64%	2.55%	7.08%
2015.2	9.83%	2.88%	6.94%
2015.3	9.40%	2.96%	6.44%
2015.4	9.86%	2.96%	6.90%
2016.1	9.70%	2.72%	6.98%
2016.2	9.48%	2.57%	6.91%
2016.3	9.74%	2.28%	7.46%
2016.4	9.83%	2.83%	7.00%
2017.1	9.72%	3.04%	6.67%
2017.2	9.64%	2.90%	6.75%
2017.3	10.00%	2.82%	7.18%
2017.4	9.91%	2.82%	7.09%
2018.1	9.69%	3.02%	6.66%
2018.2	9.75%	3.09%	6.66%
2018.3	9.69%	3.06%	6.63%
2018.4	9.52%	3.27%	6.25%
2019.1	9.72%	3.01%	6.71%
2019.2	9.58%	2.78%	6.79%
2019.3	9.53%	2.29%	7.24%
2019.4	9.89%	2.25%	7.63%
2020.1	9.72%	1.89%	7.83%
2020.2	9.58%	1.38%	8.20%
2020.3	9.30%	1.37%	7.93%
2020.4	9.56%	1.62%	7.94%
2021.1	9.45%	2.07%	7.38%
2021.2	9.47%	2.25%	7.21%
2021.3	9.27%	1.93%	7.34%
2021.4	9.68%	2.00%	7.69%
AVERAGE	10.64%	4.60%	6.04%
MEDIAN	10.59%	4.63%	6.18%



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.91503
R Square	0.83728
Adjusted R Square	0.83590
Standard Error	0.00420
Observations	120

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.010869	0.010869	601.821596	0.000000
Residual	118	0.002131	0.000018		
Total	119	0.013000			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.0867	0.001135	76.44	0.0000	0.0845	0.0890	0.0845	0.0890
U.S. Govt. 30-year Treasury	(0.5720)	0.023213	(24.64)	0.0000	(0.6179)	(0.5260)	(0.6179)	(0.5260)

	[7] U.S. Govt. 30-year Treasury	[8] Risk Premium	[9] ROE
Current 30-day average of 30-year U.S. Treasury bond yield [4]	1.87%	7.61%	9.47%
Blue Chip Near-Term Projected Forecast (Q2 2022 - Q2 2023) [5]	2.52%	7.23%	9.75%
Blue Chip Long-Term Projected Forecast (2023-2027) [6]	3.40%	6.73%	10.13%
AVERAGE			9.78%

Notes:
[1] Source: Regulatory Research Associates, rate cases through December 31, 2021
[2] Source: Bloomberg Professional, quarterly bond yields are the average of each trading day in the quarter
[3] Equals Column [1] − Column [2]
[4] Source: Bloomberg Professional, 30-day average as of December 31, 2021
[5] Source: Blue Chip Financial Forecasts, Vol. 41, No. 1, January 1, 2021, at 2
[6] Source: Blue Chip Financial Forecasts, Vol. 40, No. 12, December 1, 2021, at 14
[7] See notes [4], [5] & [6]
[8] Equals 0.086737 + (-0.571979 x Column [7])
[9] Equals Column [7] + Column [8]

Docket No. UE 399
Exhibit PAC/309
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Ann E. Bulkley

Capital Expenditures Analysis

March 2022

2022-2026 CAPITAL EXPENDITURES AS A PERCENT OF 2020 NET PLANT

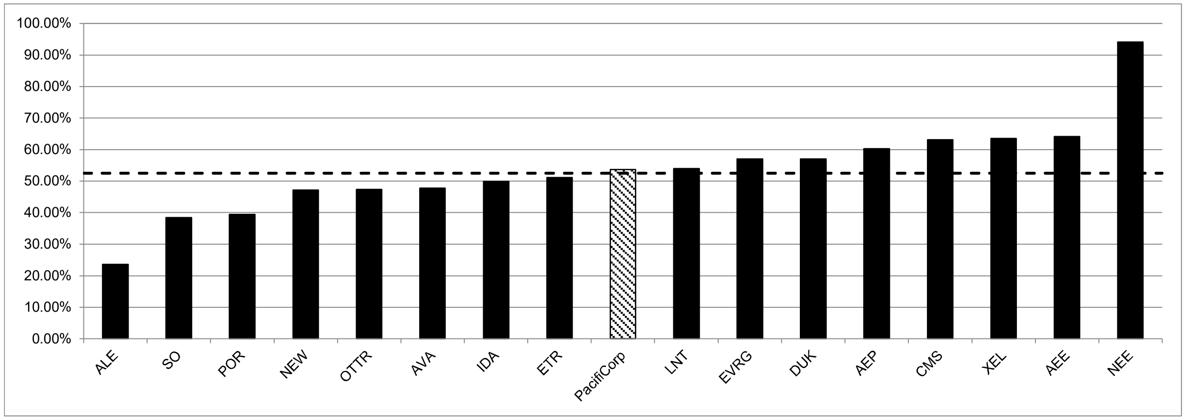
($ Millions)

			[1]	[2]	[3]	[4]	[5]	[6]	[7]	
			2020	2022	2023	2024	2025	2026	2022-26 Cap. Ex. / 2020 Net Plant	
ALLETE, Inc.		ALE								
	Capital Spending per Share			$3.70	$4.10	$4.50	$4.50	$4.50		
	Common Shares Outstanding			52.75	53.38	54.00	54.00	54.00		
	Capital Expenditures			$195.2	$218.8	$243.0	$243.0	$243.0	23.61%	1 ALE
	Net Plant		$4,840.8							
Alliant Energy Corporation		LNT								
	Capital Spending per Share			$5.30	$5.90	$6.50	$6.50	$6.50		
	Common Shares Outstanding			251.00	251.75	252.50	252.50	252.50		
	Capital Expenditures			$1,330.3	$1,485.3	$1,641.3	$1,641.3	$1,641.3	53.99%	10 LNT
	Net Plant		$14,336.0							
Ameren Corporation		AEE								
	Capital Spending per Share			$11.80	$12.28	$12.75	$12.75	$12.75		
	Common Shares Outstanding			265.00	272.50	280.00	280.00	280.00		
	Capital Expenditures			$3,127.0	$3,344.9	$3,570.0	$3,570.0	$3,570.0	64.09%	16 AEE
	Net Plant		$26,807.0							
American Electric Power Company, Inc.		AEP								
	Capital Spending per Share			$15.15	$14.45	$13.75	$13.75	$13.75		
	Common Shares Outstanding			530.00	540.00	550.00	550.00	550.00		
	Capital Expenditures			$8,029.5	$7,803.0	$7,562.5	$7,562.5	$7,562.5	60.28%	13 AEP
	Net Plant		$63,902.0							
Avista Corporation		AVA								
	Capital Spending per Share			$6.50	$6.25	$6.00	$6.00	$6.00		
	Common Shares Outstanding			73.50	76.50	79.50	79.50	79.50		
	Capital Expenditures			$477.8	$478.1	$477.0	$477.0	$477.0	47.82%	6 AVA
	Net Plant		$4,991.6							
CMS Energy Corporation		CMS								
	Capital Spending per Share			$10.35	$9.43	$8.50	$8.50	$8.50		
	Common Shares Outstanding			289.70	292.35	295.00	295.00	295.00		
	Capital Expenditures			$2,998.4	$2,755.4	$2,507.5	$2,507.5	$2,507.5	63.10%	14 CMS
	Net Plant		$21,039.0							

Duke Energy Corporation		DUK								
	Capital Spending per Share			$16.60	$16.05	$15.50	$15.50	$15.50		
	Common Shares Outstanding			770.00	770.00	770.00	770.00	770.00		
	Capital Expenditures			$12,782.0	$12,358.5	$11,935.0	$11,935.0	$11,935.0	57.07%	12 DUK
	Net Plant		$106,782.0							
Entergy Corporation		ETR								
	Capital Spending per Share			$18.95	$19.10	$19.25	$19.25	$19.25		
	Common Shares Outstanding			$205.00	206.50	208.00	208.00	208.00		
	Capital Expenditures			$3,884.8	$3,944.2	$4,004.0	$4,004.0	$4,004.0	51.07%	8 ETR
	Net Plant		$38,853.0							
Evergy, Inc.		EVRG								
	Capital Spending per Share			$8.75	$9.63	$10.50	$10.50	$10.50		
	Common Shares Outstanding			$230.00	230.00	230.00	230.00	230.00		
	Capital Expenditures			$2,012.5	$2,213.8	$2,415.0	$2,415.0	$2,415.0	57.05%	11 EVRG
	Net Plant		$20,106.0							
IDACORP, Inc.		IDA								
	Capital Spending per Share			$7.70	$8.85	$10.00	$10.00	$10.00		
	Common Shares Outstanding			50.45	50.45	50.45	50.45	50.45		
	Capital Expenditures			$388.5	$446.5	$504.5	$504.5	$504.5	49.87%	7 IDA
	Net Plant		$4,709.5							
NextEra Energy, Inc.		NEE								
	Capital Spending per Share			$7.60	$8.30	$9.00	$9.00	$9.00		
	Common Shares Outstanding			1,980	2,003	2,025	2,025.00	2,025.00		
	Capital Expenditures			$15,048.0	$16,620.8	$18,225.0	$18,225.0	$18,225.0	94.05%	17 NEE
	Net Plant		$91,803.0							
NorthWestern Corporation		NEW								
	Capital Spending per Share			$9.70	$8.23	$6.75	$6.75	$6.75		
	Common Shares Outstanding			60.00	61.00	62.00	62.00	62.00		
	Capital Expenditures			$582.0	$501.7	$418.5	$418.5	$418.5	47.23%	4 NEW
	Net Plant		$4,952.9							
Otter Tail Corporation		OTTR								
	Capital Spending per Share			$4.35	$4.55	$4.75	$4.75	$4.75		
	Common Shares Outstanding			$41.70	41.85	42.00	42.00	42.00		
	Capital Expenditures			$181.4	$190.4	$199.5	$199.5	$199.5	47.35%	5 OTTR
	Net Plant		$2,049.3							
Portland General Electric Company		POR								
	Capital Spending per Share			$7.45	$6.85	$6.25	$6.25	$6.25		
	Common Shares Outstanding			89.80	89.90	90.00	90.00	90.00		
	Capital Expenditures			$669.0	$615.8	$562.5	$562.5	$562.5	39.43%	3 POR
	Net Plant		$7,539.0							
Southern Company		SO								
	Capital Spending per Share			$6.35	$6.18	$6.00	$6.00	$6.00		
	Common Shares Outstanding			1,105	1,105	1,105	1,105	1,105		
	Capital Expenditures			$7,016.8	$6,823.4	$6,630.0	$6,630.0	$6,630.0	38.49%	2 SO
	Net Plant		$87,634.0							
Xcel Energy Inc.		XEL								
	Capital Spending per Share			$9.70	$9.85	$10.00	$10.00	$10.00		
	Common Shares Outstanding			544	549	553	553	553		
	Capital Expenditures			$5,276.8	$5,402.7	$5,530.0	$5,530.0	$5,530.0	63.49%	15 XEL
	Net Plant		$42,950.0							
PacifiCorp		PacifiCorp								
	Capital Expenditures [8]			$2,000.70	$3,317.40	$2,501.20	$2,025.00	$2,196.00		
	Net Plant [9]		$22,430.00							
									53.68%	9 PacifiCorp

Notes:
[1] - [6] Value Line November 12, 2021, December 10, 2021, January 21, 2022
[7] Equals (Column [2] + [3] + [4] + [5] + [6]) / Column [1]
[8] Source: Company Provided Data
[9] Source: Company Provided Data

2022-2026 CAPITAL EXPENDITURES AS A PERCENT OF 2020 NET PLANT



Projected CAPEX / 2020Net Plant

Rank	Company		2022-2026
1	ALLETE, Inc.	ALE	23.61%
2	Southern Company	SO	38.49%
3	Portland General Electric Company	POR	39.43%
4	NorthWestern Corporation	NEW	47.23%
5	Otter Tail Corporation	OTTR	47.35%
6	Avista Corporation	AVA	47.82%
7	IDACORP, Inc.	IDA	49.87%
8	Entergy Corporation	ETR	51.07%
9	PacifiCorp	PacifiCorp	53.68%
10	Alliant Energy Corporation	LNT	53.99%
11	Evergy, Inc.	EVRG	57.05%
12	Duke Energy Corporation	DUK	57.07%
13	American Electric Power Company, Inc.	AEP	60.28%
14	CMS Energy Corporation	CMS	63.10%
15	Xcel Energy Inc.	XEL	63.49%
16	Ameren Corporation	AEE	64.09%
17	NextEra Energy, Inc.	NEE	94.05%
	Proxy Group Median		52.53%
	PacifiCorp/Proxy Group		1.02

Notes:
Source: Exhibit PAC/309, pages 1-2 col. [7]

Docket No. UE 399
Exhibit PAC/310
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Ann E. Bulkley

Regulatory Risk Analysis

March 2022

COMPARISON OF PACIFICORP AND PROXY GROUP COMPANIES
RISK ASSESSMENT

				[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
							Non-Volumetric Rate Design				
Proxy Group Company	Operating Subsidiary	Jurisdiction	Service	Fuel Cost Recovery Mechanism	Test Year	Rate Base	Revenue Decoupling	Formula-based rates	Straight Fixed-Variable Rate Design	Non-Volumetric Rate Design	Capital Cost Recovery
ALLETE, Inc.	ALLETE (Minnesota Power)	Minnesota	Electric	Yes	Fully Forecast	Average	No	No	No	No	Yes
Alliant Energy Corporation	Interstate Power & Light Co.	Iowa	Electric	Yes	Historical	Average	No	No	No	No	No
	Interstate Power & Light Co.	Iowa	Gas	Yes	Historical	Average	No	No	No	No	No
	Wisconsin Power & Light Co.	Wisconsin	Electric	Yes	Fully Forecast	Average	No	No	No	No	No
	Wisconsin Power & Light Co.	Wisconsin	Gas	Yes	Fully Forecast	Average	No	No	No	No	No
Ameren Corporation	Ameren Illinois Co.	Illinois	Electric	N/A	Historical	Year End	No	Yes	No	Yes	No
	Ameren Illinois Co.	Illinois	Gas	Yes	Fully Forecast	Average	Partial	No	No	Yes	Yes
	Union Electric Co.	Missouri	Electric	Yes - Sharing Band	Historical	Year End	Partial	No	No	Yes	Yes
	Union Electric Co.	Missouri	Gas	Yes	Historical	Year End	Partial	No	No	Yes	Yes
American Electric Power Company, Inc.	Southwestern Electric Power Co.	Arkansas	Electric	Yes	Historical	Year End	Partial	Yes	No	Yes	Yes
	Indiana Michigan Power Co.	Indiana	Electric	Yes	Fully Forecast	Year End	Partial	No	No	Yes	Yes
	Kentucky Power Co.	Kentucky	Electric	Yes	Fully Forecast	Year End	Partial	No	No	Yes	No
	Southwestern Electric Power Co.	Louisiana	Electric	Yes	Historical	Year End	Partial	Yes	No	Yes	No
	Indiana Michigan Power Co.	Michigan	Electric	Yes	Fully Forecast	Average	No	No	No	No	No
	Ohio Power Co.	Ohio	Electric	N/A	Partially Forecast	Year End	Partial	No	No	Yes	Yes
	Public Service Co. of Oklahoma	Oklahoma	Electric	Yes	Historical	Year End	Partial	No	No	Yes	Yes
	Kingsport Power Co.	Tennessee	Electric	Yes	Fully Forecast	Average	No	No	No	No	No
	AEP Texas	Texas	Electric	N/A	Historical	Year End	No	No	No	No	Yes
	Southwestern Electric Power Co.	Texas	Electric	Yes	Historical	Year End	No	No	No	No	Yes
	Appalachian Power Co.	Virginia	Electric	Yes	Historical	Year End	No	No	No	No	Yes
	Appalachian Power Co./Wheeling Power Co.	West Virginia	Electric	Yes	Historical	Average	No	No	No	No	No
Avista Corporation	Alaska Electric Light and Power Co.	Alaska	Electric	Yes	Historical	Average	No	No	No	No	No
	Avista Corp.	Idaho	Electric	Yes - Sharing Band	Historical	Year End	Full	No	No	Yes	No
	Avista Corp.	Idaho	Gas	Yes	Historical	Year End	Full	No	No	Yes	No
	Avista Corp.	Oregon	Gas	Yes - Sharing Band	Fully Forecast	Year End	Full	No	No	Yes	No
	Avista Corp.	Washington	Electric	Yes - Sharing Band	Historical	Average	Partial	No	No	Yes	No
	Avista Corp.	Washington	Gas	Yes	Historical	Average	Partial	No	No	Yes	No
CMS Energy Corporation	Consumers Energy Co.	Michigan	Electric	Yes	Fully Forecast	Average	No	No	No	No	No
	Consumers Energy Co.	Michigan	Gas	Yes	Fully Forecast	Average	Partial	No	No	No	Yes
Duke Energy Corporation	Duke Energy Florida LLC	Florida	Electric	Yes	Fully Forecast	Year End	No	No	No	No	Yes
	Duke Energy Indiana LLC	Indiana	Electric	Yes	Historical	Year End	Partial	No	No	Yes	Yes
	Duke Energy Kentucky Inc.	Kentucky	Electric	Yes	Fully Forecast	Average	Partial	No	No	Yes	No
	Duke Energy Kentucky Inc.	Kentucky	Gas	Yes	Fully Forecast	Average	Partial	No	No	Yes	No
	Duke Energy Carolinas LLC/Duke Energy Progress LLC	North Carolina	Electric	Yes	Historical	Year End	No	No	No	No	No
	Piedmont Natural Gas Co. Inc.	North Carolina	Gas	Yes	Historical	Year End	Full	No	No	Yes	Yes
	Duke Energy Ohio Inc.	Ohio	Electric	N/A	Partially Forecast	Year End	Partial	No	No	Yes	Yes
	Duke Energy Ohio Inc.	Ohio	Gas	Yes	Partially Forecast	Year End	No	No	Yes	Yes	Yes
	Duke Energy Carolinas LLC/Duke Energy Progress LLC	South Carolina	Electric	Yes	Historical	Year End	No	No	No	No	No
	Piedmont Natural Gas Co. Inc.	South Carolina	Gas	Yes	Historical	Year End	Partial	No	No	Yes	No
	Piedmont Natural Gas Co. Inc.	Tennessee	Gas	Yes	Fully Forecast	Average	Partial	No	No	Yes	Yes
Entergy Corporation	Entergy Arkansas LLC	Arkansas	Electric	Yes	Fully Forecast	Average	Partial	Yes	No	Yes	Yes
	Entergy New Orleans LLC	Louisiana-NOCC	Electric	Yes	Partially Forecast	Year End	Partial	Yes	No	Yes	Yes
	Entergy New Orleans LLC	Louisiana-NOCC	Gas	Yes	Partially Forecast	Year End	No	Yes	No	Yes	No
	Entergy Louisiana LLC	Louisiana	Electric	Yes	Historical	Average	Partial	Yes	No	Yes	Yes
	Entergy Louisiana LLC	Louisiana	Gas	Yes	Historical	Average	Partial	Yes	No	Yes	Yes
	Entergy Mississippi LLC	Mississippi	Electric	Yes	Fully Forecast	Average	Partial	Yes	No	Yes	No
	Entergy Texas Inc.	Texas	Electric	Yes	Historical	Year End	No	No	No	No	Yes
Evergy, Inc.	Evergy Kansas Central Inc	Kansas	Electric	Yes	Historical	Year End	Partial	No	No	Yes	No
	Evergy Metro Inc.	Kansas	Electric	Yes	Historical	Year End	No	No	No	No	Yes
	Evergy Metro Inc	Missouri	Electric	Yes - Sharing Band	Historical	Year End	Partial	No	No	Yes	Yes
	Evergy Missouri West Inc.	Missouri	Electric	Yes - Sharing Band	Historical	Year End	Partial	No	No	Yes	Yes
IDACORP, Inc.	Idaho Power Co.	Idaho	Electric	Yes - Sharing Band	Partially Forecast	Year End	Full	No	No	Yes	No
	Idaho Power Co.	Oregon	Electric	Yes - Sharing Band	Partially Forecast	Average	No	No	No	No	No
NextEra Energy, Inc.	Florida Power & Light Co.	Florida	Electric	Yes	Fully Forecast	Average	No	No	No	No	Yes
	Gulf Power Co.	Florida	Electric	Yes	Fully Forecast	Average	No	No	No	No	Yes
	Pivotal Utility Holdings Inc.	Florida	Gas	Yes	Fully Forecast	Average	No	No	No	No	Yes
	Lone Star Transmission LLC	Texas	Electric	N/A	Historical	Year End	No	No	No	No	Yes
NorthWestern Corporation	NorthWestern Corporation	Montana	Electric	Yes - Sharing Band	Historical	Average	Partial	No	No	Yes	No
	NorthWestern Corporation	Montana	Gas	Yes	Historical	Average	No	No	No	No	No
	NorthWestern Corporation	Nebraska	Gas	Yes	Historical	Year End	No	No	No	No	No
	NorthWestern Corporation	South Dakota	Electric	Yes	Historical	Average	No	No	No	No	No
	NorthWestern Corporation	South Dakota	Gas	Yes	Historical	Average	No	No	No	No	No

Otter Tail Corporation	Otter Tail Power Co.	Minnesota	Electric	Yes		Fully Forecast		Average		No		No		No		No		No
	Otter Tail Power Co.	North Dakota	Electric	Yes		Fully Forecast		Average		No		No		No		No		Yes
	Otter Tail Power Co.	South Dakota	Electric	Yes		Historical		Average		No		No		No		No		Yes
Portland General Electric Company	Portland General Electric Co.	Oregon	Electric	Yes - Sharing Band		Fully Forecast		Year End		Partial		No		No		Yes		Yes
Southern Company	Alabama Power Co.	Alabama	Electric	Yes		Fully Forecast		Average		No		Yes		No		Yes		Yes
	Georgia Power Co.	Georgia	Electric	Yes		Fully Forecast		Average		No		Yes		No		Yes		Yes
	Atlanta Gas & Light Co.	Georgia	Gas	N/A		Fully Forecast		Average		No		Yes		Yes		Yes		Yes
	Northern Illinois Gas Co.	Illinois	Gas	Yes		Fully Forecast		Average		Partial		No		No		Yes		Yes
	Mississippi Power Co.	Mississippi	Electric	Yes		Fully Forecast		Year End		Partial		Yes		No		Yes		No
	Chattanooga Gas Co.	Tennessee	Gas	Yes		Fully Forecast		Average		Partial		Yes		No		Yes		No
	Virginia Natural Gas Inc.	Virginia	Gas	Yes		Historical		Average		Partial		No		No		Yes		Yes
Xcel Energy Inc.	Public Service Co. of Colorado	Colorado	Electric	Yes		Historical		Average		Partial		No		No		Yes		Yes
	Public Service Co. of Colorado	Colorado	Gas	Yes		Historical		Year End		Partial		No		No		Yes		Yes
	Northern States Power Co.-Minnesota	Minnesota	Electric	Yes		Fully Forecast		Average		Partial		Yes		No		Yes		No
	Northern States Power Co.-Minnesota	Minnesota	Gas	Yes		Fully Forecast		Average		No		No		No		No		Yes
	Southwestern Public Service Co.	New Mexico	Electric	Yes		Historical		Year End		No		No		No		No		No
	Northern States Power Co.-Minnesota	North Dakota	Electric	Yes		Fully Forecast		Average		No		No		No		No		Yes
	Northern States Power Co.-Minnesota	North Dakota	Gas	Yes		Fully Forecast		Average		No		No		Yes		Yes		No
	Northern States Power Co.-Minnesota	South Dakota	Electric	Yes		Historical		Average		Partial		No		No		Yes		Yes
	Southwestern Public Service Co.	Texas	Electric	Yes		Historical		Year End		No		No		No		No		Yes
	Northern States Power Co.-Wisconsin	Wisconsin	Electric	Yes		Fully Forecast		Average		No		No		No		No		No
	Northern States Power Co.-Wisconsin	Wisconsin	Gas	Yes		Fully Forecast		Average		No		No		No		No		No
									Revenue Decoupling		Formula-based rates		SFV Rates Design		Non-Volumetric Rate Design		CCRM	
Proxy Group Average			Yes	68	Fully Forec	35	Year End	38	Full	5	Yes	15	Yes	3	Yes	47	Yes	44
			No	0	Partially Fo	7	Average	46	Partial	36	No	69	No	81	No	37	No	40
			N/A	6	Historical	42			No	43								
			Yes- Sharing Banc	10														
			Yes/N/A	88.10%	Forecast	50.00%	Year End	45.24%	RDM	48.81%	Yes	17.86%	Yes	3.57%	Yes	55.95%	CCRM	52.38%
PacifiCorp	PacifiCorp [8]	Oregon	Electric	Yes-Sharing Band		Fully Forecast		Average		No		No		No		No		Yes

Notes:
[1] Data provided by S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated November 12, 2019.
[2] Sources: Regulatory Research Associates, effective as of September 30, 2021
[3] Sources: Regulatory Research Associates, effective as of September 30, 2021

[4] Sources: S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated November 12, 2019. Operating subsidiaries not covered in this report were excluded from this exhibit. NWE Electric MT - Company 2020 Form 10-K. PSCO Electric CO and SO TN - S&P Global Market Intelligence.
[5] Sources: Company Form 10-K, Company Tariffs, S&P Global Market Intelligence
[6] Sources: Company Form 10-K, Company Tariffs, S&P Global Market Intelligence
[7] Equals IF(AND([3]=No, [4]=No, [5]=No), No, Yes)
[8] Sources: S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated November 12, 2019. Operating subsidiaries not covered in this report were excluded from this exhibit.

Docket No. UE 399
Exhibit PAC/311
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Ann E. Bulkley

Capital Structure Analysis

March 2022

CAPITAL STRUCTURE ANALYSIS

		Median of Most Recent 8 Quarters			
Proxy Group Company	Ticker	Common Equity Ratio	Preferred Equity Ratio	Long-Term Debt Ratio	Total Capitalization
ALLETE, Inc.	ALE	56.86%	0.00%	43.14%	100.00%
Alliant Energy Corporation	LNT	51.58%	1.67%	46.75%	100.00%
Ameren Corporation	AEE	52.60%	0.76%	46.65%	100.00%
American Electric Power Company, Inc.	AEP	48.27%	0.00%	51.73%	100.00%
Avista Corporation	AVA	51.08%	0.00%	48.92%	100.00%
CMS Energy Corporation	CMS	51.22%	0.22%	48.56%	100.00%
Duke Energy Corporation	DUK	52.81%	0.00%	47.19%	100.00%
Entergy Corporation	ETR	46.85%	0.11%	53.04%	100.00%
Evergy, Inc.	EVRG	59.61%	0.00%	40.39%	100.00%
IDACORP, Inc.	IDA	53.86%	0.28%	45.86%	100.00%
NextEra Energy, Inc.	NEE	61.11%	0.00%	38.89%	100.00%
NorthWestern Corporation	NWE	47.43%	0.00%	52.57%	100.00%
Otter Tail Corporation	OTTR	53.13%	0.00%	46.87%	100.00%
Portland General Electric Company	POR	47.81%	0.00%	52.19%	100.00%
The Southern Company	SO	54.23%	0.58%	45.19%	100.00%
Xcel Energy Inc.	XEL	54.04%	0.00%	45.96%	100.00%
Median		52.71%	0.00%	46.81%	
Maximum		61.11%	1.67%	53.04%	
Minimum		46.85%	0.00%	38.89%	

Notes:
[1] Ratios are weighted by actual common capital, preferred capital, and long-term debt of the operating subsidiaries.
[2] Electric operating subsidiaries with data listed as N/A from S&P Capital IQ Pro have been excluded from the analysis.

Docket No. UE 399
Exhibit PAC/400
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Michael G. Wilding

March 2022

TABLE OF CONTENTS

ATTACHED EXHIBIT

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 Michael G. Wilding. My business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My title is Vice President, Energy Supply Management.

Q. Briefly describe your education and business experience.

A. I received a Master of Accounting from Weber State University and a Bachelor of Science degree in accounting from Utah State University. As Vice President, Energy Supply Management (ESM), my responsibilities include directing PacifiCorp's front office organization in commercial and trading activities. ESM is responsible for commercially managing PacifiCorp's diverse generation portfolio. This includes the electric and natural gas hedging, term and day-ahead trading, real-time trading and system balancing. Prior to assuming my current position in February 2021, I worked on various regulatory projects including general rate cases, the multi-state process (MSP), and net power cost (NPC) filings. I have been employed by PacifiCorp since 2014.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have filed testimony in proceedings before the Public Utility Commission of Oregon (Commission), and the public utility commissions in California, Idaho, Utah, Washington, and Wyoming.

II. PURPOSE OF TESTIMONY

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

A. My testimony addresses the persistent under-recovery of net power costs and proposes two modest changes to the mechanisms through which the Company has the opportunity to recover its NPC. First, I propose a rate-year update to the transition adjustment mechanism (TAM) and the inclusion of more accurate hydrological information. Second, I propose certain modifications to the power cost adjustment mechanism (PCAM).

III. NPC BACKGROUND

Q. Please describe how PacifiCorp recovers its Oregon-allocated NPC.

A. In Oregon, PacifiCorp forecasts a level of NPC for the following calendar year (test year) through the TAM. PacifiCorp uses its Aurora model to forecast NPC for the test year. This forecast level of NPC is recovered through Schedule 201 during the test - year. In the year following the test year, PacifiCorp files a PCAM, which is a mechanism that allows for recovery or return of un-forecasted deviations in NPC. PacifiCorp has never triggered a rate change through the PCAM.

Q. Why are NPC reset annually?

A. In approving annual power cost updates through the TAM, the Commission has recognized that "it is important to update the forecast of power costs included in rates to account for new information, *e.g.,* on expected market prices for electricity and natural gas, and for new…purchase power contracts" and that "[i]f the forecast is not updated each year, then [the utility] will be exposed to more than normal business risk."[1] NPC can vary significantly year-to-year for a variety of reasons, including changes to loads, fuel costs, market prices, and renewable resource availability. This variability makes it difficult to accurately forecast NPC for ratemaking purposes.

Q. Please briefly describe the TAM.

A. The purpose of the TAM is to capture costs associated with direct access and prevent unwarranted cost shifting between cost-of-service customers and customers that elect direct access service.[2] Significantly, the TAM also sets PacifiCorp's Oregon-allocated NPC for the upcoming year.[3] The direct access transition adjustments are calculated by comparing the value of energy used to serve direct access loads with the cost-of-service rate under the customers' specific energy-only tariff. The Commission adopted an annual NPC update to ensure that both the value of freed-up energy and the cost-of-service rate are calculated for the same period using the same data. The Commission has articulated the importance of accurate NPC modeling in the TAM:

> PacifiCorp's TAM is an annual filing in which PacifiCorp projects the amount of [NPC] to be reflected in customer rates for the following year, as well as to set transition charges for customers electing to move to direct access. The TAM effectively removes regulatory lag for the company because the forecasts are used to adjust rates. For that reason, the accuracy of the forecasts is of significant importance to setting fair just and reasonable rates. Our goal, therefore, is to achieve an accurate forecast of PacifiCorp's [NPC] for the upcoming year.[4]

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[1] *In the matter of Portland General Elec. Co., Request for a General Rate Revision,* et al, Docket Nos. UE 180, UE 181, and UE 184, Order No. 07-015 at 18 (Jan. 12, 2007).
[2] *In the matter of Pacific Power & Light Company (dba PacifiCorp) Request for a General Rate Increase in the Company's Oregon Annual Revenues*, Docket No. UE 170, Order No. 05-1050 at 21 (Sept. 28, 2005).
[3] *In the matter of PacifiCorp, dba Pacific Power 2008 Transition Adjustment Mechanism*, Docket No. UE 191, Order No. 07-446 at 2 (Oct. 17, 2007).
[4] *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).

Q. Please briefly describe PacifiCorp's PCAM authorized by the Commission.

A. Commission Order 12-493 approved a PCAM to allow PacifiCorp to recover the difference between actual PCAM costs incurred to serve customers and the base PCAM costs established in PacifiCorp's annual TAM filing.[5] PCAM costs include NPC, other revenues, and federal production tax credits (PTC). As the Commission observed when it adopted a PCAM for Portland General Electric Company, the PCAM has been designed so that the utility "will bear normal business risk associated with actual power costs varying from forecast."[6]

Q. Please describe the relationship of the TAM and PCAM.

A. Each year the PCAM compares the NPC collected from Oregon customers in rates set in the TAM to the actual Oregon-allocated NPC. The PCAM variance, however, is subject to an asymmetrical deadband between a $30 million under-collection and a $15 million over-collection, a symmetrical sharing band where the Company absorbs 10 percent of the variance outside the deadband, and finally a symmetrical earnings test where the collection or refund of a PCAM variance is limited to amounts that will bring PacifiCorp to within 100 basis points of the Company's authorized return on equity (ROE). Additionally, the amortization of deferred amounts is capped at six percent of the revenue for the preceding calendar year.

IV. RATE-YEAR UPDATE FOR THE TAM

Q. Please describe the change PacifiCorp is proposing in the TAM.

A. PacifiCorp is proposing a limited update to take place during the rate year. This

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[5] *In the matter of PacifiCorp, dba Pacific Power, Request for a General Rate Case*, Docket No. UE 246, Order No. 12-493 (Dec. 20, 2012).
[6] Order No. 07-015 at 17-19.

update would update to the latest official forward price curve, include the latest short-term purchases and sales, and the most recent hydrologic forecast for the test-year.

Q. How will the Rate-Year Update work?

A. PacifiCorp will update Schedule 201 rates during the rate year with a filing that occurs on March 1. Similar to the final TAM filing, PacifiCorp will file the information, workpapers, and tariff sheets supporting the Rate-Year Update with a NPC forecast based on the updated information outlined above. After Staff and interested parties have sufficient time to review, the Commission would approve the update, with a rate effective date of April 1.

Q. Why is PacifiCorp proposing the Rate-Year Update?

A. The purpose of the Rate-Year Update is to update NPC to incorporate the latest information and costs that are necessary to meet PacifiCorp's resource adequacy requirements for the Western Power Pool's (WPP) Western Resource Adequacy Program (WRAP). It also notable that WPP WRAP program is also currently proposed by Commission Staff as a standard in Oregon's resource adequacy program.[7] By February 28 of each year, PacifiCorp will have completed the process to cure any issues with capacity deficiencies for the summer of the rate year for the WRAP. Additionally, PacifiCorp will be close to the March 31 submittal date for the winter period in the WRAP which begins on November 1 of the rate year. Therefore, the Rate-Year Update will allow PacifiCorp to update NPC for any new short-term contracts that were necessary to meet WRAP resource adequacy requirements for the summer, and PacifiCorp will also have good information on meeting the winter

[7] *Investigation into Resource Adequacy in the State*, Docket No. UM 2143, Staff Straw Proposal (Oct. 15, 2021).

resource adequacy requirements as well. Additionally, this update will occur in spring, which means the NPC forecast will allow the incorporation of the latest forward prices and hydrologic conditions.

Q. Is PacifiCorp proposing to update Direct Access Rates in the Rate-Year Update?

A. No, PacifiCorp is not proposing changes to the Direct Access Rates that would occur outside the Direct Access pricing period. The purpose of the Rate-Year Update is to capture the acquisition of any resources or transactions to meet the Company's resource adequacy requirements and set the TAM rates as accurately as possible. 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.

V. CHANGES TO THE TAM GUIDELINES

Q. Will the Rate-Year Update require changes to the TAM guidelines?

A. Yes. The TAM guidelines will need to be updated to allow for a Rate-Year Update and to include using forecast hydro generation in place of the normalized hydro generation that is used today for the Lewis River hydro project.

Q. What other changes is PacifiCorp proposing to the TAM guidelines?

A. To increase the accuracy of hydro generation in the TAM, PacifiCorp is proposing to replace normalized forecast data with more accurate, rate year specific hydrologic information as an input to calculate hydro generation in the rebuttal, indicative, final, and Rate-Year Updates for the TAM. Hydro generation has a significant impact on PacifiCorp NPC and by incorporating rate year hydrologic data, like the official forward price curve, market transactions and updates, PacifiCorp will be providing a more accurate NPC forecast.

Q. How Does PacifiCorp currently develop its normalized hydrological forecast?

A. PacifiCorp develops its hydrological forecast in a three-step process. The first step estimates normalized annual flow forecast for the Merwin plant. Historical annual median flow is calculated based on the flow data available since 1929 and used as the normalized annual flow forecast for the Merwin plant. The second step estimates normalized monthly flow forecast for the Merwin, Yale and Swift plants. Monthly median flows for the Merwin plant are calculated based on the 10-year monthly flow data. Their relative sizes are used to subdivide the normalized annual flow forecast into the normalized monthly flow forecasts. For each month, the relative flow for the Yale and Swift plants to the Merwin plant is also estimated, and used to determine the normalized monthly flow forecast for the Yale and Swift plants. The third step estimates normalized weekly generation forecasts. The Vista DSS model, which is set up for the Lewis River project, is run using the normalized monthly flow forecast as one of the inputs, and produces normalized weekly generation forecasts. Past TAM filings have used these normalized forecasts.

Q. Is PacifiCorp proposing to use an independent third-party source for the forecast hydrologic information?

A. Yes, for the Lewis River hydro project, PacifiCorp is proposing to use information from the Northwest River Forecast Center (NWRFC), and from the National Oceanic and Atmospheric Administration (NOAA), which produces a rolling 12-month hydrological forecast. This is the same source of hydrologic information that is used by the Idaho Power Company for its March update in their annual power cost update.[8]

Q. What is the specific hydrologic information that will be used?

A. In line with current practice, the Company will use historical monthly streamflow data, estimated for each key project site, to develop its forecasts based on normalized data. For the Final Update in November, the 12-month Monthly Water Supply Volume Forecasts published by the NWRFC of the NOAA will be used to overwrite the January to November forecast values. This updated forecast will provide more exact streamflow data than the normalized estimates used in the initial forecast in the rate year. Since the December period of the normalized data is not updated in this forecast, PacifiCorp will use the Seasonal Outlooks for Temperature and Precipitation published by the Climate Prediction Center of NOAA for December if its warranted. For the Rate-Year Update in February, the updated data will be reviewed and compared with Monthly Water Supply Volume Forecast by NWRFC, Stream Forecast from the Natural Resources Conservation Service of the United States Department of Agriculture as well as Seasonal Hydro Forecast provided by Upstream Tech, the river forecast company that PacifiCorp contracts to support the Lewis River project, in order to ensure we are using the most current hydrological forecasts available.

[8] *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).

Q. Which hydro resources will use forecasted hydrological forecasts as input the hydro generation modeling?

The Lewis River hydro generation resources (Swift, Yale and Merwin) will utilize forecasted hydrology as an input to hydro generation modeling.

Q. How will this information be incorporated in the Aurora forecast?

A. Currently, hydro generation data is pre-processed outside of the Aurora model utilizing the normalized forecast. Hydro generation is input into Aurora as a fixed generation schedule. To accommodate the switch from the normalized forecast for January to November to the proposed rate year rolling forecast data, the Aurora input files for the hydro generation would be updated with a new generation forecast utilizing forecasted hydrology as part of the Company's standard input update process for the Final Update.

Q. How will integration of this data lead to a more accurate NPC forecast in the TAM?

A. Hydrological conditions and operational requirements change over time, so using the most current hydrologic data and forecasts available rather than normalized data accumulated over many years is expected to produce more relevant and accurate generation forecasts for the given rate year.

Q. Is the hydro forecast in the spring better than ones in the winter?

A. Yes, snow accumulation and the melt processes play a key role in the Lewis basin hydrology. Snowpack accumulated in the winter is the major source of water for the surface runoff during the snowmelt season and the groundwater flow during the dry season. Historically, snowpack around the Lewis basin often peaks around early

April. Therefore, hydrologic information available in the spring, including snowpack conditions and spring weather forecast, could provide valuable information to improve the hydro forecast for the Lewis basin in the snowmelt and following dry seasons. This means that the hydrologic forecast that is included in the Rate-Year Update will provide the most accurate information for the TAM.

Q. How will the hydrologic information be incorporated into the various updates?

A. Based on the availability of the data, the initial TAM filing will still use normalized data, however, the subsequent filings use various update forecasts. Using the 2024 TAM as an example, the table below provides a summary of how the hydro information will be incorporated into the various updates.

Table 1

2024 TAM Filing	Month	Forecast Hydro Period	Normalized Hydro Period
Initial	April 2023	N/A	Jan-Dec 2024
Rebuttal	July 2023	Jan-May 2024	Jun – Dec 2024
Final Update	November 2023	Jan-Sept 2024	Oct-Dec 2024
Rate-Year Update	March 2024	Jan-Dec 2024	N/A

Q. Is PacifiCorp proposing other changes to the TAM Guidelines?

A. Yes, as part of this general rate case, PacifiCorp is taking the opportunity to incorporate the elements from various TAM Orders into the TAM Guidelines to allow for the codification of all the changes that have occurred since the TAM Guidelines were originally adopted. In Exhibit PAC/401, PacifiCorp has provided a draft of these revised TAM Guidelines that detail the changes that have been proposed and the source of those proposed changes.

VI. PCAM CHANGES

Q. What are the changes PacifiCorp is proposing to the PCAM?

A. PacifiCorp is proposing three changes to the structure of the PCAM:

1. PacifiCorp is proposing to adjust the deadbands to be symmetrical by moving the upper deadband from $30 million to $15 million;
2. Setting the earnings test at PacifiCorp's authorized ROE; and
3. PacifiCorp may propose that the NPC costs of certain months be recovered outside the deadbands, sharing bands, and earnings test.

Q. The Commission denied PacifiCorp's proposed changes to the PCAM in PacifiCorp's last general rate case. Why is PacifiCorp again proposing changes to the PCAM?

A. When the Commission declined to adopt PacifiCorp's proposed changes to the PCAM mechanism, it was noted that "PacifiCorp has not demonstrated a fundamental change in the risk balance between customers and the company that occurs with its power costs."[9] During the last general rate case, there was a lot of time spent on PacifiCorp's modeling of NPC and the systematic under-recovery of NPC. Admittedly, the Company did not address the "fundamental change in the risk balance between customers and the company." However, the loss of dispatchable generation across the West and the consequential change in the market has fundamentally altered the risk balance on power costs. PacifiCorp is proposing these changes as consistent

[9] *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).

with the purpose of the PCAM, which is to allow adjustment for "unusual events and [to] capture power cost variances that exceed those considered normal business risk for the utility."[10] I intend to address the risk balance and show that it has indeed shifted and warrants small but fair changes to the PCAM.

Q. At a high level, how have the operating and market environments the Company is operating in changed over the past decade?

A. While there have been likely too many changes impacting PacifiCorp and the entire utility sector to mention them all, some of the key changes are related to resource mix, supply and demand, macroeconomic factors, technology adoption and change, environmental policy changes, as well as climate change related impacts and associated mitigation strategies. Additionally, the Western Energy Imbalance Market (EIM), operated by the California Independent System Operator (CAISO) was launched in 2014 and has seen extensive growth in members and benefits. Similarly, electrification of transportation and building has not only become mainstream but is part of the Company's resource strategy. The Company's 2021 Integrated Resource Plan (IRP) provides a detailed illustration of the above mentioned and other factors. Regional resource adequacy assessments highlight that there are resource adequacy risks through the mid-2020s. The addition of variable energy resources replacing traditional "baseload" resources may act to tighten market supply. There are risks to whether the market is available to purchase power and risks to the price will impact NPC for customers. Energy policies in the western states have been enacted to lower emissions. Climate change is impacting summer and winter loads forecasts. It is also

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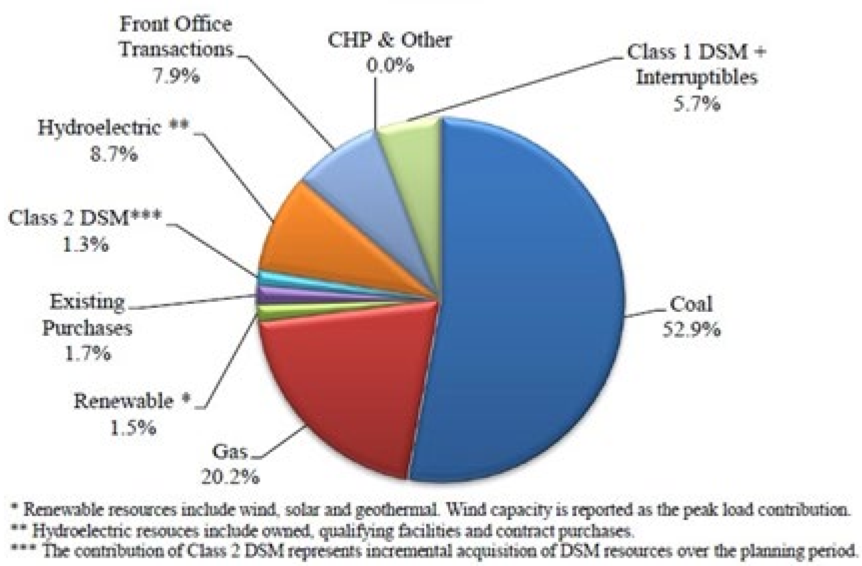
[10] *In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Case*, Docket No. UE 246, Order No. 12-493 at 13 (Dec. 20, 2012).

impacting renewable solar and wind resources generation, natural gas generation, as well as hydro generation to serve loads.

Q. How has PacifiCorp's resource mix changed since 2013?

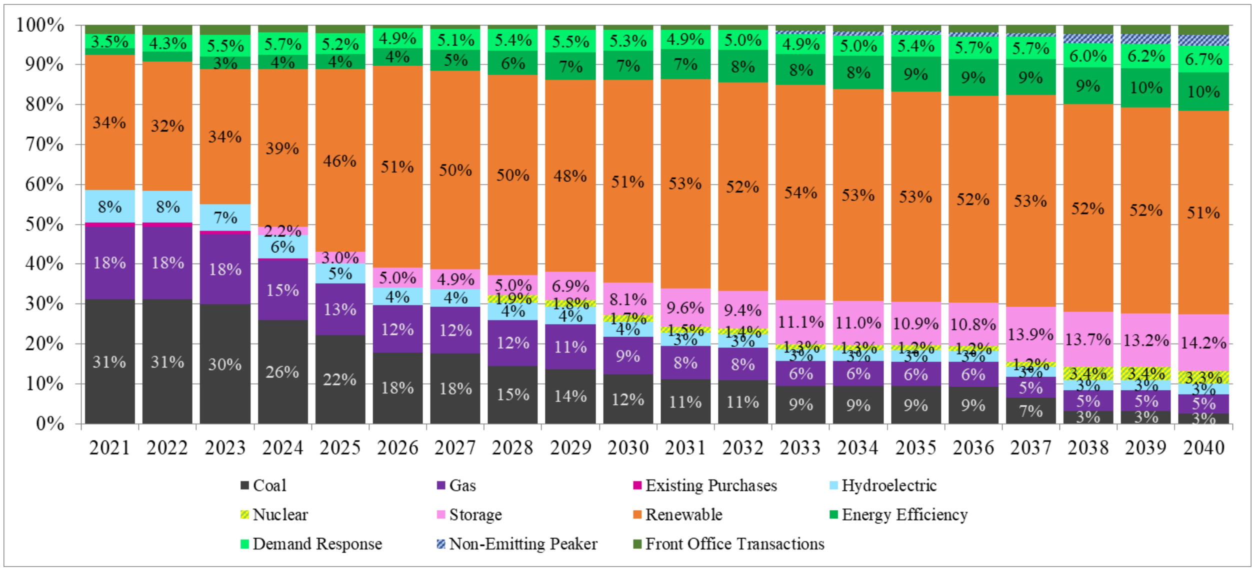
A. In 2013, more that 70 percent of the Company's capacity mix was made up of dispatchable thermal resources. After adding in, hydro, front-office transactions, and long-term purchases more than 90 percent of the Company's capacity mix was from sources with firm energy delivery schedules. In contrast, in 2022, only 49 percent of the Company's capacity mix is from dispatchable thermal resources, and 32 percent is from renewable resources. While renewable resources are cost-effective for customers and carry many benefits, they do not have firm energy delivery schedules. Figure 1 and Figure 2 below presents the Company's capacity mix in 2013 and capacity mix forecast from the 2021 IRP.

Figure 1: PacifiCorp's 2013 Capacity Mix[11]



[11] *In the matter of PacifiCorp, dba Pacific Power, 2013 Integrated Resource Plan*, Docket No. LC 57, PacifiCorp's 2013 Integrated Resource Plan at 229 (Apr. 30, 2013).

Figure 2: PacifiCorp 2021 Capacity Mix[12]



Q. Have the changes in the Company's resource portfolio affected the risk balance between customers and the Company with respect to power costs? Please explain.

A. Yes. There is substantially more uncertainty in 2022 as PacifiCorp relies on cost-effective variable energy resources. Additionally, PacifiCorp has substantially less control over power costs than it did in 2013.

In 2013, a capacity mix with a firm energy delivery schedule meant there was less uncertainty in power costs. As coal made up 52 percent of the capacity mix a significant portion of power costs could be contracted through coal supply agreements thus protecting the Company and customers to changes in market prices. Additionally, significant amounts of generation output were not dependent upon

[12] *In the matter of PacifiCorp, dba Pacific Power, 2021 Integrated Resource Plan*, Docket No. LC 77, PacifiCorp's 2021 Integrated Resource Plan at 305 (Sept. 1, 2021).

weather. The greatest uncertainty of the Company's generation was the risk of an unplanned outage.

In 2022, this is no longer the case. Variable energy resources such as wind and solar provide several benefits to customers, notably low-cost power with environmental benefits, but they present unique complexities and challenges to hedging, balancing, and operation of the system. Unlike coal, natural gas, and certain hydroelectric resources that can be dispatched to follow changes in customer demands, these resources are non-dispatchable. They generate power intermittently when the wind blows or the sun shines.

The growing penetration of renewable energy has created significant hourly volatility to the supply of energy. This, along with the retirement of firm thermal generation capacity, has resulted in wide swings in the value of energy across a given day. Output from variable energy resources (VERS) cannot be controlled, in contrast to a traditional resource mix of dispatchable resources that could be controlled and where variability of those resources largely stemmed from outages. The traditional resource mix lent itself better to dead bands and sharing bands as the Company has some ability to prevent unplanned outages, whereas the Company has no control over the wind or sun to fuel variable resource generation.

Electric utilities across the west, including the Company, have and will continue to acquire significant additional variable energy resources, which increase the challenge of hedging and balancing the system. These factors have increased the complexity and difficulty and costs of balancing the system. Customers enjoy the benefits of these low-cost and zero emission resources, but absent changes to the

PCAM, do not adequately share the costs the Company must incur to respond to the variable nature of these resources.

Q. Has the western United States seen a similar shift in the greater resource mix?

Yes. As illustrated in Figure 3 below, even at the greater Western Energy Coordinating Council (WECC)-wide level, the resource capacity mix between 2010 and 2019 demonstrates growth in solar and wind along with a reduction in base load capacity (defined by WECC to include coal, gas, geothermal and nuclear).

Figure 3: 2010–2019 Capacity by State[13]

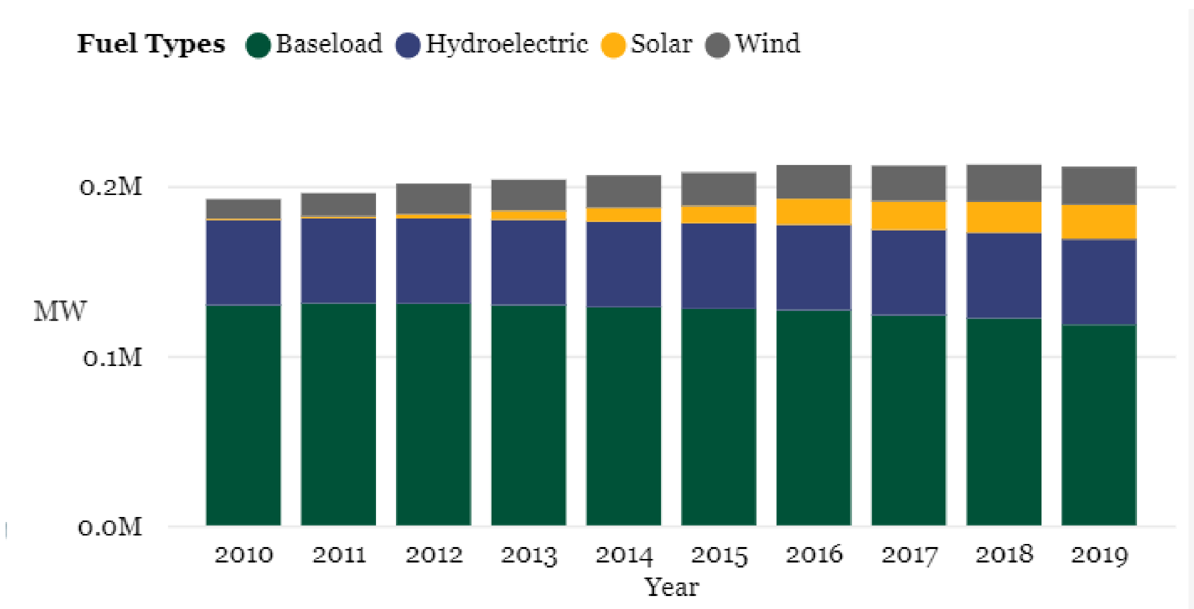


Figure 4 and Figure 5 below illustrate the historical change in regional capacity for the WECC Northwest Region and the WECC's Rocky Mountain Region, both of which are relevant to the Company's resource footprint. While the resource fleet differs by region, both regions have witnessed significant changes in the makeup of the regional generation resources.

[13] *Capacity by State, State of the Interconnection,* WESTERN ELECTRICITY COORDINATING COUNCIL, https://www.wecc.org/epubs/StateOfTheInterconnection/Pages/Capacity-by-State.aspx.

Figure 4[14]

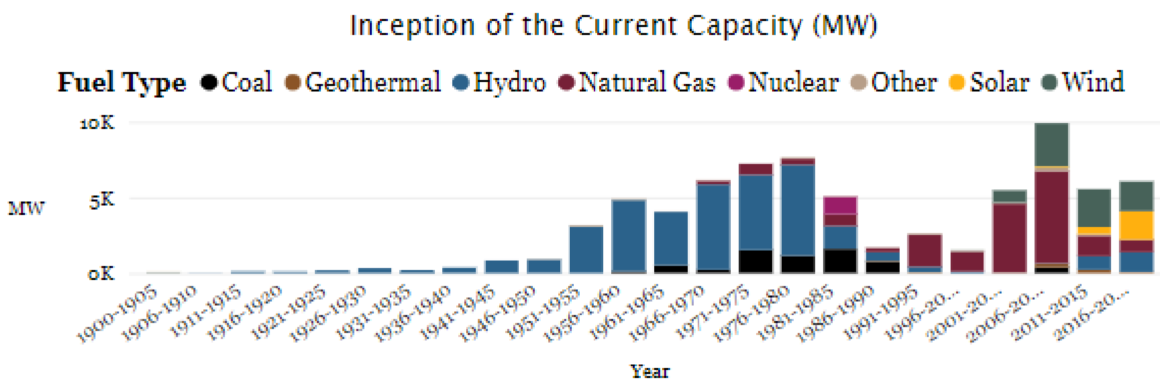
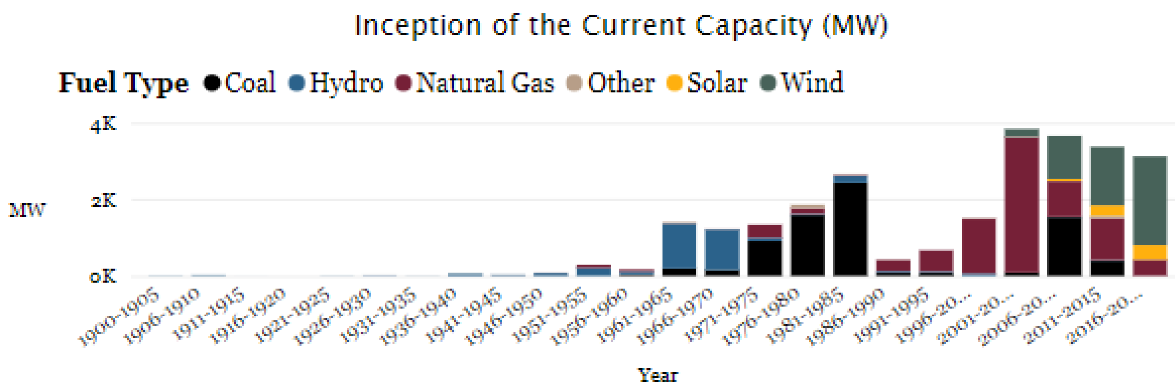


Figure 5[15]



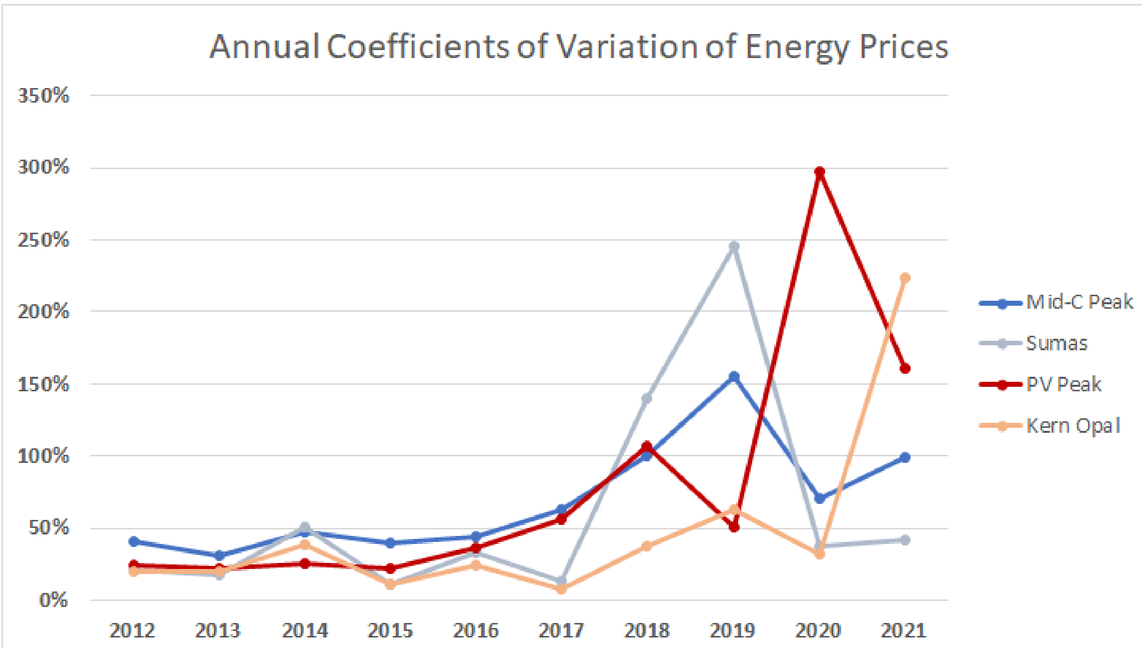
Q. How has the change in the regional resource mix impacted electric and natural gas markets?

The increasing amounts and relative proportions of non-dispatchable variable energy resources have increased the complexity of hedging and balancing activities for the entire region. Power and natural gas markets have seen a marked increase in volatility of supply and demand and the resulting impact on market transaction prices. Figure 6 shows the annual coefficient of variation of daily spot market prices for the

[14] *Capacity, State of the Interconnection,* WESTERN ELECTRICITY COORDINATING COUNCIL, https://www.wecc.org/epubs/StateOfTheInterconnection/Pages/Capacity.aspx.
[15] *Id.*

power and gas markets the Company most frequently transacts in. As Figure 6 depicts, there has been a substantial change in volatility across the markets that PacifiCorp participates in since 2017.

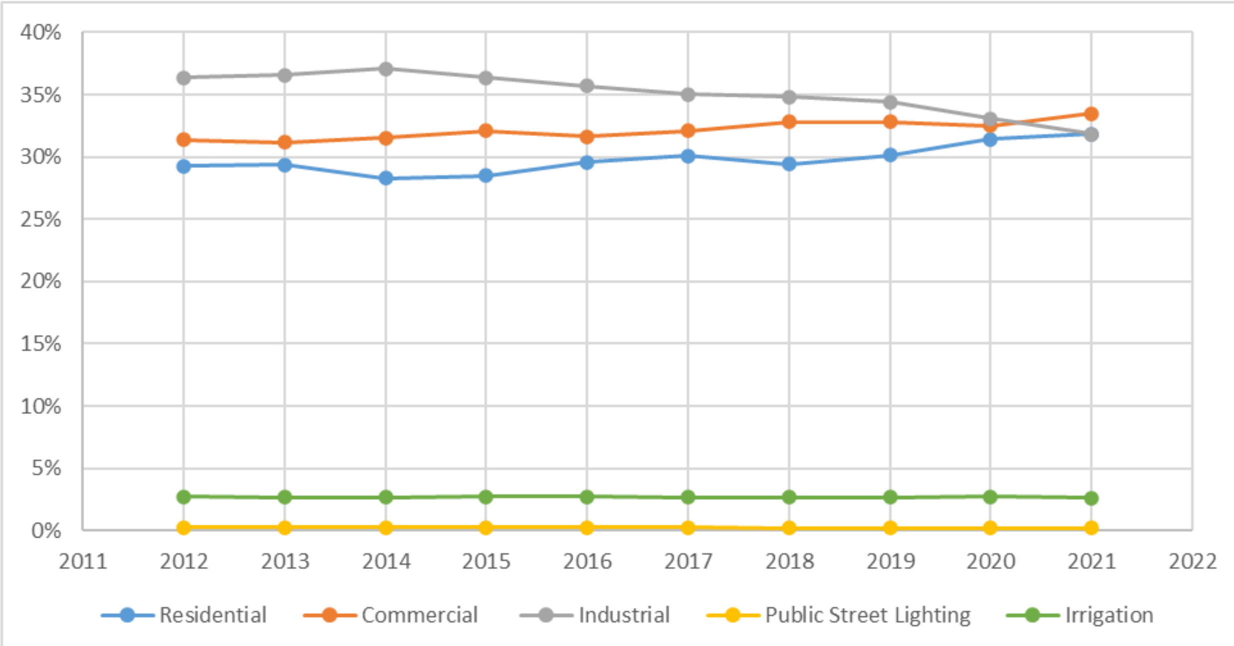
Figure 6



Q. Please summarize the key changes in customer demands from 2012 to 2021.

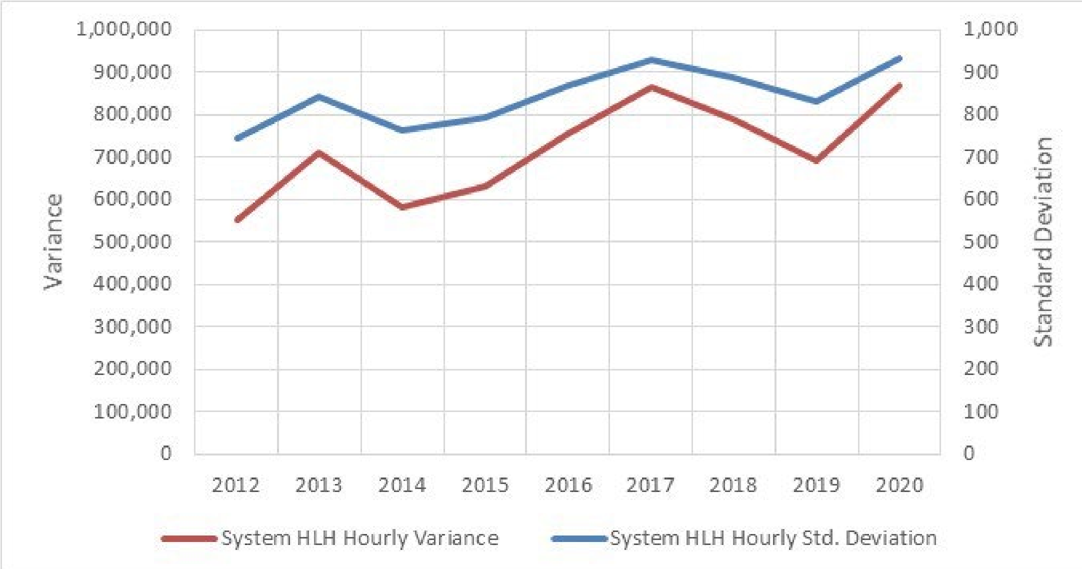
A. The Company has observed the composition of load served has been changing over time. Figure 7 presents the composition of loads by class for PacifiCorp's total system. As illustrated, over the past decade, the proportion of residential and commercial loads have increased, while the proportion of industrial loads have declined over time.

Figure 7: Actual Retail Sales Class Composition for PacifiCorp's full system (2012 – 2021)



Collectively, these factors have resulted in larger load volatility given the lower load factors of residential and commercial loads. Industrial loads tend to have less fluctuation throughout the year. Specifically, since 2012, the volatility of the hourly system load for heavy load hours (HLH), as indicated by the variance and the standard deviation, show a clear upwards trend (Figure 8).

Figure 8: Total Company Heavy Load Hour Hourly System Load Variability (2012 – 2020)



Q. Why does the change in retail load composition hourly load variability represent a shift in power cost risk balance?

A. It represents another input to the Company's resource management equation that has shown an increase in variability over the past 10 years. Having loads with greater volatility results in more expensive hedging costs.

Q. How do the changes in the Company's resource portfolio and changes in customer demands affect the company's ability to forecast power costs?

A. As the certainty of generation and demand forecasts decreases, so does the ability to accurately forecast actual power costs. The fewer dispatchable resources at a company's disposal, the less certainty exists around the ultimate cost to serve load. That is because absent very large-scale energy storage, total costs depend increasingly on the timing between VERS generation and customer load. Periods of low VERS generation and high load result in large volumes of power subject to spot market prices. The same applies to periods of high VERS generation and low customer loads.

Q. How does the Company hedge its power and natural gas price risk?

A. The Company forecasts power and natural gas positions based on all available information (loads, renewable resources, thermal plant availability, etc.). Natural gas price risk is hedged primarily with swap contracts. These contracts provide a financial hedge where the Company pays a fixed price to a counterparty and in return receives an index settlement price for a predetermined volume of natural gas. The settlement price becomes known in the final days before the contract month. However, this settlement price may still differ from balancing transaction prices the Company must engage in on a daily basis for operations.

Power is hedged primarily with fixed-price physical "on-peak" and "off-peak" contracts, typically at the Mid-Columbia or Palo Verde market hubs for the west and east sides of the system, respectively. An "on-peak" forward purchase or sale results in the transfer of an equal volume of power for the sixteen "on-peak" hours each Monday through Saturday excluding holidays. An "off-peak" forward purchase or sale results in the transfer of an equal volume of power for the eight "off-peak" hours each Monday through Saturday and all 24 hours of a Sunday or a holiday. These "on-peak" and "off-peak" products are liquid and readily available. Products of narrower groupings of hours are not available in sufficient quantity for hedging.

Q. Have the instruments available to the Company to hedge changed materially from 2012 to 2022?

A. No. Despite the increased volatility in size and value of individual hours throughout the day, power hedges are still purchased or sold in on-peak, and off-peak blocks.

Q. Has the complexity to hedge power costs changed from 2012 to 2022?

A. Yes. As the hourly load and resource balance of the Company's portfolio sees wider variations in hourly open positions, these instruments are increasingly less effective in providing flat (balanced load and resource) positions. If traders wish to purchase on-peak forward hedges to provide price protection for the highest peak hours of a month, these transactions, with equal volumes across all on-peak hours create significant additional length in hours other than the highest peak hours. As delivery nears, this creates additional challenges to balance the system by dispatching resources down or selling the excess energy in hours with more surplus energy, often at a substantially lower price than paid for the entire block. Conversely, if traders purchase a lower quantity to avoid excess length across these hours, this may leave the highest peak hours short. Purchasing these highest peak hours in the spot market can be very expensive as supply and demand forces often cause extreme spikes in the price of power, spikes that have increased in size and frequency as all utilities struggle with uncontrollable changes in VERS output and increasingly volatile loads. Lastly, this could cause reliability risk as there is no guarantee that the energy is in fact available when needed.

Q. How does moving to a symmetrical $15 million deadband in the PCAM help PacifiCorp to rebalance the risk between customers and the Company in light of the changed conditions described above?

A. This adjustment was inspired by Staff's testimony on alternative adjustments to the PCAM from PacifiCorp's last general rate case, where Staff noted that making the deadbands symmetrical "would allow customers and shareholders to share costs and risks."[16] Staff also suggested reducing the size of the deadbands,[17] which would also increase the likelihood of adjustments to the mechanism. Incorporating these two adjustments would help rebalance the risk between the Company and customers by allowing PacifiCorp a better opportunity to recover the significant deviations from forecast NPC.

Q. Please explain PacifiCorp's proposal to set the PCAM earnings test at PacifiCorp's authorized ROE?

A. Currently, the PCAM earnings test is set at 100 basis points of PacifiCorp's authorized ROE. This means that if PacifiCorp's earned ROE is within plus or minus 100 basis points of the authorized ROE, there will be no recovery from or refund to customers. PacifiCorp is proposing to change the earnings test so that the 100 basis point collaris removed, but PacifiCorp's recovery of costs in the PCAM is capped when the authorized ROE is reached. Additionally, if PacifiCorp will be providing a credit to customers under the PCAM, that credit is capped at PacifiCorp's ROE instead of being capped at 100 basis points above the ROE.

[16] *In the Matter of PacifiCorp d/b/a Pacific Power, Request for a General Rate Revision*, Docket No. UE 374, Staff/2400, Gibbens/32 (Jul. 24, 2020).
[17] *Id.* at Staff/2400, Gibbens/31.

Q. Does PacifiCorp's proposal still provide a mechanism that is consistent with the purposes identified by the Commission?

A. Yes, by setting the earnings test at PacifiCorp's authorized ROE, and keeping the deadbands, it still ensures that rate adjustments only occur for significant NPC variations. Additionally, the earnings test would now prevent the PCAM from allowing the utility to earn beyond its authorized ROE.

Q. Please explain PacifiCorp's final proposed change to the PCAM.

A. The final adjustment is intended to introduce more flexibility into the PCAM mechanism. It allows the Company to identify certain specific and unusual months that resulted in significant costs and therefore a significant deviation from the NPC baseline forecast for that month. The Company can then propose to recover the costs of those unusual months through the PCAM mechanism but outside the deadbands, sharing bands, and earnings test.

Q. How does PacifiCorp propose this change would function in the PCAM mechanism?

A. PacifiCorp would identify a month that resulted in unusual or significant costs that deviate from the forecast and would propose the recovery of those costs that deviated from the NPC forecast when the PCAM filing is made on May 15. PacifiCorp would bear the burden of showing that these costs were appropriate for recovery outside the deadbands, sharing bands, and earnings test. Stakeholders could then review the costs and present testimony to the Commission opposing or supporting PacifiCorp's proposal, and the Commission would then determine whether they are appropriate for recovery on a case-by-case basis.

Q. Can you provide an example of a significant and unusual month that resulted in a large deviation from baseline net power costs??

A. Yes. On October 9, 2018, the Enbridge natural gas pipeline that transports natural gas produced in the Western Canadian Sedimentary Basin to consumers in British Columbia (B.C.) and, through interconnecting pipelines, the Northwestern United States (U.S.), experienced a massive rupture. The pipeline was brought back into service in late October 2018, however, at a reduced capacity until testing of the many segments of the pipeline were completed. Spot natural gas prices at the Sumas B.C.-U.S. border trading point traded as high as $159 per million British thermal units on days of intense demand due to cold weather and reduced natural gas supply in the first quarter of 2019.

The pipeline rupture and reduced operating capacity impacted electricity prices primarily at the Mid-Columbia power market hub, but also increased electricity prices and natural gas prices at other trading points where PacifiCorp transacts. PacifiCorp has one natural gas-fired generator—the Chehalis plant—that is sourced from the Sumas natural gas hub. Due to the pipeline rupture, and cold weather impacting B.C. and the Northwest there were times of limited availability of natural gas flowing to the Sumas gas hub. With the inability to fully utilize the Chehalis plant in part due to strong natural gas demand from residential and commercial customers in B.C. due to weather conditions, PacifiCorp was faced with more market purchases during times of much higher prices at Mid-Columbia which ultimately increased NPC.

In February of 2019, an extreme cold event was forecasted early in the month and combined with limited hydro resources being available in the region significantly increased power prices. These conditions resulted in a significant deviation from forecast net power costs in February of 2019. Specifically, there was a $12.0 million (Oregon-allocated) deviation from forecasted NPC for that month in the PCAM.[18]

Q. Can you describe how this event is outside the normal business risk associated with NPC?

A This catastrophic event and corresponding rise in natural gas prices was not forecastable and was completely outside the Company's control. The current structure of the PCAM inappropriately balances the risk between the customers and the Company. PacifiCorp's proposal to recover actual NPC outside the restrictions of the PCAM during aberrant months can help restore the balance.

VII. EIM AND WRAP FEES

Q. Are there any new fees associated with PacifiCorp's participation in regional organizations that are going to be included in base rates?

A. Yes, PacifiCorp is proposing to include fees related to the EIM Body of State Regulators (BOSR) and the WPP WRAP in base rates.

Q. Please explain the purpose of the EIM BOSR.

A. The EIM BOSR is a body that addresses the regional nature of the EIM through the EIM governance process. The purpose of the EIM BOSR is to provide "a forum for state commissioners to (1) select a voting member of the EIM Governing Body Nominating Committee, (2) learn about and discuss the EIM and CAISO markets,

[18] *In the Matter of PacifiCorp d/b/a Pacific Power, 2019 Power Cost Adjustment Mechanism*, Docket No. UE 379, PAC/101, Webb/1 (May 15, 2020).

and (3) express a common position in CAISO stakeholder processes or to the EIM Governing Body on EIM issues."[19]

Q. Please explain the new fee that is associated with the EIM BOSR?

A. As described by the EIM BOSR, the fee supports the BOSR's expenses and support the body's goal that "consistent, and informed regulator engagement on regional market operations and developments is crucial to efficient and sustainable markets that deliver public benefits."[20] The Oregon-allocated portion of PacifiCorp's fee is $23,463.

Q. What is the WPP WRAP?

A. As I discuss earlier in my testimony, the WPP WRAP is the new regional resource adequacy initiation that is being implemented by many utilities and power producers across the west to ensure that the region is better able to plan for our regional resource adequacy needs.

Q. Please explain the WPP WRAP Fee.

A. There are three main components of the WRAP fee. First is facilitation and coordination services, including the use of staff resources related to facilitation and coordination services provided by WPP Corporation in connection with the Phase 3A Scope of Work. Secondly, WPP will bill to the participants the expenses the WPP Corporation incurs directly to perform the Phase 3A Scope of Work, including costs associated with contracting for a Program Operator. Finally, there are binding

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[19] *EIM BOSR Energy Imbalance Market Body of State Regulators*, WESTERN INTERSTATE ENERGY BOARD ofpc2022), https://www.westernenergyboard.org/energy-imbalance-market-body-of-state-regulators/.
[20] *2022 Business Plan and Budget*, WESTERN ENERGY IMBALANCE MARKET BODY OF STATE REGULATORS (Oct. 15, 2021) *available at* https://www.westernenergyboard.org/wp-content/uploads/EIM-BOSR-2022-Business-Plan-and-Budget-15-Oct-2022.pdf.

program preparation costs including preparation for Federal Energy Regulatory Commission filings, setting up an independent board and preparing the WPP Corporation to undertake the obligations required to house the program as a public utility under the Federal Power Act. The Oregon-allocated cost of this fee is $260,703.

VIII. CONCLUSION

Q. Please summarize your recommendation to the Commission.

A. The Commission should adopt PacifiCorp's proposal to allow for a Rate-Year Update and incorporate more accurate hydrologic data in the TAM. Additionally, the balance of risk around NPC has shifted substantially since the PCAM was originally adopted, and as a result, PacifiCorp has proposed modest changes to the PCAM mechanism. PacifiCorp recommends that these changes be adopted. Finally, I recommend that the Commission authorize certain new fees around participation in important regional organizations be included in base rates.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 399
Exhibit PAC/401
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Michael G. Wilding

Proposed Transition Adjustment Mechanism Guidelines

March 2022

PACIFICORP
OREGON TRANSITION ADJUSTMENT MECHANISM (TAM)
General Guidelines

PacifiCorp's (PacifiCorp or the Company) Transition Adjustment Mechanism (TAM) is an annual filing with the objective to update the forecast net power costs (NPC) 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.

When filed on a stand-alone basis, the TAM is intended to be narrower and more streamlined than when the TAM is filed in or processed concurrently with a general rate case. In any case, parties to the TAM proceeding should have a full opportunity to review, challenge and litigate issues raised in the case. Parties may address the issue of whether a particular TAM proceeding should have three rounds of testimony or five at the prehearing conference.

Issues related to the prudence of contracts, the appropriate modeling of contracts and known and measurable changes to inputs for existing methodologies are within the proper scope of a stand-alone TAM proceeding. Nothing in these guidelines prevents any Party, including the Company, from advocating in a future general rate case or other proceeding other than a stand-alone TAM, that the TAM should be eliminated or revised.

A. NPC

Commented [A1]: New Section included for clarification.

NPC includes the amounts booked to the following Federal Energy Regulatory Commission (FERC) accounts:

FERC Account	Description
Account 447	Sales for resale, excluding revenues that are not modeled in the NPC forecast
Account 501	Fuel, steam generation; excluding costs that are not modeled in the NPC forecast
Account 503	Steam from other sources
Account 547	Fuel, other generation
Account 555	Purchased power, excluding the Bonneville Power Administration (BPA) residential exchange credit pass-through if applicable
Account 565	Transmission of electricity by others.

B. Initial Filing – Forecast NPC

Each year, the Company will make an Initial Filing to forecast NPC for the following calendar year, and set direct access transition adjustments for the following calendar year. In any future TAM filings after UE 400, the Initial Filing will be consistent with the following provisions:

1. At least 30 days prior to the Initial Filing, the Company will provide a pre-filing notice of substantial changes to the methodologies used to forecast NPC. The Company will include in its TAM filing a justification for each substantial change in forecast methodology, calculation of cost elements, or other major data input changes. For each change, where practical, the Company will also provide workpapers that contain a side-by-side comparison of NPC forecast model results with and without the proposed change.

Commented [A2]: Order No. 09-432

2. The Company will include in the NPC forecast the variable costs and dispatch benefits of new resources that are not eligible for inclusion in the Renewable Adjustment Clause in its NPC in stand-alone TAM proceedings, irrespective of whether the fixed capital costs of the new resource are already included in rates, if: (a) the Company acquired the resource prior to April 1st of the year of the stand-alone TAM filing, or (b) the Company built the resource and it was used and useful prior to April 1st of the year of the stand-alone TAM filing.

Commented [A3]: Order No. 09-432

3. The prudence of the decision to build or acquire the resource may be determined in the stand-alone TAM proceeding prior to including the variable costs and dispatch benefits in rates. The Company will provide notice to the parties if a new resource subject to this section will be included in the TAM filing by March 1st of the year of the stand-alone TAM filing.

4. The Initial Filing will include updates to all of the NPC components identified in Section A. These costs will be based on the Company's most recent official forward price curve, forecast load and allocation factors. In a stand-alone TAM filing, the Company will also update other revenues that are tracked in FERC Account 456 - Other Electric Revenue. When a TAM is filed in or processed concurrently with a general rate case, this element may be included in the TAM or the general rate case. Additionally, the TAM forecast will include production tax credits (PTC).

5. In the Initial Filing the Company will identify and provide adequate support for all known contracts it expects to be updated or added in the Rebuttal and Final Updates. The Company may update or add a contract not identified in the Initial Filing if the Company demonstrates that it has followed the notification procedures in Section A4 of these guidelines and: (1) the new contract or contract update is based upon new information of which the Company reasonably became aware after the NPC study for the Initial Filing was completed; or (2) the omission resulted from a mistake that occurred despite the Company's reasonable diligence in meeting its

obligations under this Section. The Company will also identify any contracts modeled in the test period under which the Company has made a liquidated damages claim.

6. 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 summary of all identified corrections or omissions to the components included in the Initial Filing 15 business days before Staff and Intervenor Direct Testimony is due.

7. The Company will provide access to the NPC model to Parties when it makes its Initial Filing, provided that the Party has entered into a confidentiality agreement with the Company or is subject to a protective order applicable to the relevant TAM or general rate proceeding. The Company agrees to provide an Aurora license to Commission Staff and intervenors for the TAM. PacifiCorp will provide all inputs, data, model settings, additional constraints, and any other modeling changes that are identical to those included in the Aurora model runs used for the Company's TAM application. The Parties preserve their right to challenge the confidential designation of any documents or data.

Commented [A4]: Order No. 20-392

8. The Company agrees to conduct one Aurora model run per intervenor, so long as the request is reasonable and the Company has reasonable time to complete the request during future NPC forecast mechanism proceedings.

Commented [A5]: Order No. 20-392

9. The Company will provide workpapers and other supporting documents as specified in Attachment A.

10. The Parties agree to ask the Commission to make the protective order for the next TAM an ongoing protective order which will continue to be effective in future TAM proceedings.

11. The Company agrees to provide testimony in the initial TAM or other NPC forecast filing regarding the prudence of any Coal Supply Agreements (CSA) that were entered into after its reply testimony of the previous year's NPC forecast proceeding. PacifiCorp will notify Parties in the event of the execution of a CSA following the Company's initial testimony but prior to conclusion of the NPC forecast filing and work with Parties to identify the appropriate review timeline, regulatory process and rate implementation.

12. The Company will provide workpapers in the filing to support the depreciable lives of Bridger Coal Company assets.

Commented [A6]: Order No. 20-392

13. In future power cost forecast proceedings, the Company agrees to provide the Commission for the most recent past actual calendar year: for each hour of the sales period: the $/megawatt-hour (MWh) of bilateral trades total wholesale sales revenue($); total energy delivered (MWh) through wholesales sales; hourly generation logs for

PacifiCorp owned generation; and monthly generation unit production costs ($/MWh). If the Company joins expanded markets in the future such as the proposed California Independent System Operator Extended Day-Ahead Market, the Company agrees to work with intervenors to identify additional wholesale sales data to be provided in future forecast NPC filings.

Commented [A7]: Order No. 20-392

14. The Company will show the output (MWh) and PTC benefits ($) for its wind fleet. The Company will explain its grossed-up PTC value used for the PTC benefits explain and quantify the other NPC benefits from the wind projects, whether the wind output displaces the Company's higher cost generation, or excess wind output is forecast to be sold to the market with revenues that benefit customers.

15. Within 30 days of the Initial Filing, PacifiCorp will deliver to the Parties a sample calculation of Schedule 296 as applicable to customers currently served under rate schedules 30 and 48 (Primary).

Commented [A8]: Order No. 20-392

16. These Guidelines do not limit the ability of other Parties to propose updates consistent with these Guidelines after the Company's Initial Filing.

C. Rebuttal Update Filing – Forecast NPC

At the time the Company makes its Rebuttal Update Filing, it will include an update to forecast NPC consistent with the following provisions:

1. The Company will update the following NPC components, subject to the Guidelines:

    a. Most recent official forward price curve.

    b. New power, fuel and transportation/transmission contracts, both physical and financial, and updates to existing contracts. These contracts include:

        i. wholesale electric sales and purchase contracts that are for long term firm sales and purchases, short term firm sales and purchases, or exchanges and storage with and without energy or capacity prices;

        ii. coal and natural gas sales, purchases and transportation contracts;

        iii. wheeling contracts; and

        iv. coal contracts for mines directly or indirectly owned by the Company.

        v. The latest hydrology condition forecast available from the National Oceanic and Atmospheric Administration's (NOAA) Northwest River Forecast Center (NWRFC);

Commented [A9]: New Section – See Testimony

These transactions may have fixed prices or prices linked to market indexes. They may require physical deliveries or be settled financially *(e.g.,* swaps). Contracts must be independent and verifiable.

2. In its Rebuttal Update Filing, the Company may make corrections to or address omissions in the components included in the Initial Filing. The Company may make corrections or address omissions in the components included in the Rebuttal Update Filing within five business days of the date of filing of the Rebuttal Update. The Company agrees to provide notice of any impending correction promptly after the discovery of the error and agrees to correct all errors and omissions within five business days of the initial Rebuttal Update Filing.

3. Parties reserve all of their procedural rights, including the right to submit data requests and seek postponement of the hearing, related to the correction of the Rebuttal Update Filing.

4. The Company will provide workpapers and the other supporting documents as specified in Attachment A.

D. Final Updates – Forecast NPC

The Company will file Final Updates to forecast NPC and calculate transition adjustments as follows, subject to the Guidelines:

1. At least five business days prior to the direct access window, the Company will:

    a. File an update to forecast NPC, incorporating the following:

        i. Commission-ordered adjustments;

        ii. Forward Price Curve from within nine days of the filing date;

        iii. New contracts, or updates to existing contracts. These contracts include: (a) wholesale electric sales and purchase contracts that are for long term firm sales and purchases, short term firm sales and purchases, or exchanges and storage with and without energy or capacity prices; and (b) natural gas sales and purchase contracts. These transactions may have fixed prices or prices linked to market indexes. They may require physical deliveries or be settled financially (e.g., swaps);

        iv. The latest hydrology condition forecast available from the NOAA NWRFC;

    b. Post indicative transition adjustments for Schedules 294 and 295;

Commented [A10]: New Section – See Testimony

c. Provide indicative supply service NPC rates (to be Schedule 201); and

d. Provide an attestation that will confirm that all contracts executed prior to the contract lockdown date have been included in the Indicative Filing and will identify any exceptions and the reason why such contracts were excluded. The attestation will also include a statement confirming that, for the executed power purchase agreements with new qualifying facilities (QFs) included in the TAM, PacifiCorp has a commercially reasonable good faith belief that these QFs will reach commercial operation during the rate effective period based on the information known to the Company as of the contract lockdown date. This attestation does not require the Company to opine on the commercial viability of any QF.

Commented [A11]: Order No. 10-363 and Order No. 14-331

2. On November 15, in accordance with OAR 860-038-0275(1), the Company will:

   a. File an update to NPC incorporating the forward price curve from within seven days of the filing date.

   b. Post final transition adjustments for Schedules 294 and 295.

      i. Transition Adjustments in Schedules 294 and 295 will be calculated based on the Final Update and consistent with the modification to the calculation described in Section 15 of the Stipulation adopted by the Commission in Order 08-543 in Docket UE-199 and modified so that any remaining monthly thermal generation that is backed down for assumed direct access load will be priced at the simple monthly average of the California-Oregon Border (COB) price, the Mid-Columbia price, and the avoided cost of thermal generation as determined by Aurora The monthly COB and Mid-Columbia prices will be applied to the heavy load hours or light load hours separately. The existing balancing account mechanisms will remain in effect.

   c. Provide supply service NPC rates (to be Schedule 201)

3. The Company will provide workpapers and other supporting documents for both the Indicative and Final Update filings as specified in Attachment A.

4. <u>Challenges to Final Updates</u>. Without waiving any procedural rights, the Parties agree to make a good faith effort to follow the following procedures for challenges to the Final Updates and compliance filing. Staff and Intervenors retain their procedural rights to raise any issue regarding the Company's Final Updates to the Commission prior to and during the Commission public meeting, including filing for a deferral of costs related to the final TAM updates or requesting that a portion of the TAM be allowed subject to refund.

a. PacifiCorp agrees to make a good faith effort to respond to all discovery requests after the Indicative Filing in five business days.

b. At least 10 business days before the Commission public meeting scheduled immediately prior to the effective date of the compliance filing, a Party will make a good faith effort to provide notice to the Parties of any potential concerns with the Company's Final Updates. The notice will identify the specific elements of the Updates that are relevant to the potential challenge and provide an explanation of the Party's concern.

c. No more than five business days after receiving the Party's notice, the Company will provide an initial response to the Parties regarding the concerns raised in the notice and the Parties will work to reach resolution of the issue.

d. If the matter is not resolved by the Parties prior the Commission public meeting, the Parties may make recommendations to the Commission at the public meeting to set a process to resolve the matter, if additional process is required. The recommendations may include that a specific amount of the tariff change will be subject to deferral until the Commission resolves the matter through additional process.

e. The Company will not oppose the filing of a deferral of any limited and specific cost which is identified by the Parties at least 10 business days before the Commission public meeting. Specifically, the Company will not challenge the deferral on the basis that it fails to meet the Commission's standards for deferred accounting as initially set forth in Order No. 05-1070 (docket UM 1147), including issues related to the materiality of the filing and a showing of substantial harm. The Company otherwise retains the right to object to subject to refund or deferral treatment.

f. The Parties agree to request a schedule that will result in a Commission decision within 90 days of the effective date for new rates for any additional process after the Commission public meeting.

g. If the final Commission decision on any challenges to the Final Updates results in changes to the transition adjustments approved in Schedules 294 and 295, the Company may reflect in the direct access balancing account any difference between the approved transition adjustments and the transition adjustments that would have been in effect consistent with the Commission's decision on the challenged items.

Commented [A12]: Order No. 10-363 and 13-474

E. Rate Year TAM Update

Commented [A13]: New Section – See Testimony

1. On March 1 of the rate year (after the Final Update), the Company will file the Rate Year Update filing to update Schedule 201 rates to account for the following updates:

   a. The latest forward price curve available to the Company;

b. New contracts, or updates to existing contracts. These contracts include: (a) wholesale electric sales and purchase contracts that are for long term firm sales and purchases, short term firm sales and purchases, or exchanges and storage with and without energy or capacity prices; and (b) natural gas sales and purchase contracts. These transactions may have fixed prices or prices linked to market indexes. They may require physical deliveries or be settled financially (e.g., swaps);

c. The latest hydrology condition forecast available from the NOAA NWRFC;

2. These rates will take effect April 1, and any challenges will follow the process laid out in the preceding section D. 4.

F. Rate Design

1. In the Company's current general rate case, proposed NPC are unbundled from other generation costs. All NPC will be collected through a new Schedule 201, Annual Power Cost Adjustment, which will be applied as a rider to Schedule 200. Schedule 200 will continue to collect other generation costs.

2. In any future TAM filed in or processed concurrently with a general rate case, the TAM rate design test year will be the general rate case rate design test year. In a stand-alone TAM, the TAM rate design test year will be the forecast test year during which the Schedule 201 rates will be effective.

3. In any future TAM filed in or processed concurrently with a general rate case, proposed Schedule 201 revenues by rate schedule will be determined by spreading the total forecast NPC for the test year to the rate schedules in the same manner as the revenues for Schedule 200 are spread to the rate schedules: based on the functionalized revenue requirement as determined by the Commission based upon a Cost of Service study, or by the method proscribed by the Commission in the most recent general rate case or Commission proceeding regarding rate spread and rate design.

4. In any future stand-alone TAM, Proposed Schedule 201 revenues by rate schedule will be determined by spreading the total forecast NPC for the test year to the rate schedules based upon each schedule's proportion of "Present Schedule 201 revenues." "Present Schedule 201 revenues" for the test year shall reflect the projected test year sales forecasts. Proposed Schedule 201 rate design shall reflect the method prescribed by the Commission in the most recent general rate case or other Commission proceeding regarding rate spread and rate design.

G. TAM Filings Made in or Processed Concurrently with a General Rate Case

1. If the Company files a general rate case prior to April 1 in a given year, then the Company may file the TAM before April 1. If the Company chooses not to file a TAM prior to April 1, then it must file on April 1. If the TAM is filed on a stand-alone basis,

it will be filed no later than April 1. In order to accommodate the direct access window that begins November 15, the TAM may be bifurcated from the full general rate case in order to allow for a Commission decision by November 1. Bifurcation of the TAM does not alter any provision below.

2. When a TAM is filed in or processed concurrently with a general rate case, the Company or any Party may propose changes to how the Company's Rate Mitigation Adjustment or other rate spread tools should operate in a stand-alone TAM filing made before the TAM is again filed in or processed concurrently with a general rate case.

3. When a TAM is filed in or processed concurrently with a general rate case, the TAM will be subject to the Update Filings identified above and the agreements on workpapers and other supporting documents specific in Attachment A.

H. Other Provisions

1. These guidelines do not limit the ability of the Company or other Parties to propose changes to these guidelines, including changes to the cost elements that will comprise NPC in stand-alone TAM proceedings or in future general rate cases.

REDACTED
Docket No. UE 399
Exhibit PAC/500
Witness: Timothy J. Hemstreet

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Direct Testimony of Timothy J. Hemstreet

March 2022

TABLE OF CONTENTS

I. INTRODUCTION AND QUALIFICATIONS

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

A. My name is Timothy J. Hemstreet. My business address is 825 NE Multnomah Street, Suite 1800, Portland, Oregon 97232. My title is Managing Director of Renewable Energy Development for PacifiCorp.

Q. Please describe your education and professional experience.

A. I hold a Bachelor of Science degree in Civil Engineering from the University of Notre Dame in Indiana and a Master of Science degree in Civil Engineering from the University of Texas at Austin. I am also a Registered Professional Engineer in the state of Oregon. Before joining PacifiCorp in 2004, I held positions in engineering consulting at CH2M HILL (now Jacobs Engineering, Inc.) and environmental compliance at RR Donnelley Norwest, Inc. Since joining PacifiCorp, I have held positions in environmental policy and compliance, engineering, project management, and hydroelectric project licensing and program management. In 2016, I assumed a role in renewable energy development, focusing on PacifiCorp's wind repowering effort, and assumed my current role in June 2019, in which I oversee the development of renewable energy resources that enhance and complement PacifiCorp's existing renewable energy resource portfolio.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have previously sponsored testimony in California, Idaho, Oregon, Utah, Washington, and Wyoming.

II. PURPOSE OF TESTIMONY

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

A. The purpose of my testimony is to provide an overview of the TB Flats Wind Project and provide an update on the status of the project.

Q. Did the Company include the TB Flats Wind Project in its recent general rate case in docket UE 374 (2021 Rate Case)[1]?

A. Yes. The TB Flats Wind Project was included in the Company's revenue requirement in the 2021 Rate Case, and the Commission found the project prudent and in the public interest; however, as a result of the construction delays associated with the coronavirus pandemic, the project could not be completed in 2020 and only costs associated with turbines that achieved commercial operation by December 20, 2020, were included in rates. When it became apparent that full completion of the project would not occur by June 30, 2021, the Company met with parties in the 2021 Rate Case to discuss the best means of reflecting the full cost of the project in customer rates and as a result of those discussions determined that it would seek recovery for the remaining project costs in its next general rate case.

III. TB FLATS WIND PROJECT

Q. Please provide a brief overview of the TB Flats Wind Project.

A. TB Flats is a 500-megawatt (MW) wind generation facility and associated infrastructure, located on approximately 41,000 acres of leased private and state land in Carbon and Albany Counties, Wyoming. The facilities consist of 132

[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).

wind turbine generators (WTGs), an electrical collector system, collector substations, access roads, meteorological towers, an operations and management building, communication equipment, and supervisory control and data acquisition control equipment.

Q. What are the details of the technologies that are used in this project?

A. The TB Flats Wind Project uses modern WTG equipment supplied by Vestas-American Wind Technology, Inc. (Vestas), consisting of 28 Vestas model V110-2.0 WTGs and 104 Vestas model V136-4.3 WTGs. The Vestas WTGs are pitch-regulated upwind turbines with active yaw, gearboxes and three-bladed rotors. The V110-2.0 WTG has a 2.0 MW generator capacity, a rotor with a 110-meter diameter, and a hub height of 80 meters. The V136-4.3 WTG has a 4.3 MW generator capacity, a rotor with a 136-meter diameter, and a hub height of 82 meters. The WTGs use a microprocessor-controlled pitch control system that allows the WTGs to operate with a variable rotor speed to help maintain output at or near their rated power.

Q. Please describe any changes to the Company's existing utility plant/system that were necessary to integrate the TB Flats Wind Project with the Company's system.

A. Integration of the TB Flats Wind Project required the completion of specific interconnection facilities and network upgrades to allow the project to interconnect to the Company's electrical transmission system. The interconnection facilities consisted of circuit breakers and metering at the point of interconnection and the network upgrades consisted of the installation of new breakers and corresponding bus and relay upgrades at the Shirley Basin substation, and a new transmission line from the Shirley Basin substation to the Aeolus substation.

Q. What is the current construction status of the TB Flats Wind Project?

A. All of the 132 WTGs have been erected and commissioned, and the project is serving customers.

Q. What was the impact of the coronavirus pandemic on construction at the TB Flats Wind Project?

A. The pandemic caused severe delays in the delivery of wind turbine equipment to the project. The pandemic first impacted the production of wind turbine components and electrical parts sourced by the turbine supplier from Asia, where the impacts of the pandemic were first experienced and factory shutdowns occurred. These impacts then spread to European manufacturing facilities producing wind turbine components necessary for the project. Ultimately, the wave of global manufacturing shutdowns affected domestic WTG manufacturing and assembly facilities. When production resumed, adherence to worker safety protocols and reduced workforce slowed productivity. In addition to the shutdown of manufacturing facilities, impacts to logistics were experienced that delayed the movement of manufactured components to final WTG manufacturing and assembly facilities located in Colorado, and from those facilities to the project site. When equipment was received, it often was not able to be delivered to the site in an efficient manner to support the construction sequence for the project given the logistics constraints that were being experienced. Due to the turbine equipment delivery delays, 28 WTGs were unable to be delivered to the site during the 2020 construction season in time to allow for their erection in 2020 prior to the onset of winter weather conditions and high wind speeds that preclude efficient delivery, construction, commissioning, and maintenance activities.

In addition to the delays associated with receiving wind turbine components to the project site, construction productivity was also affected. Worker safety protocols implemented in conformance with public health guidelines reduced productivity, slowing construction efforts. Labor resources were also limited by adherence to crew quarantine protocols following documented coronavirus exposures, as well as reduced staffing levels as a result of fewer workers being able or willing to work under the health and safety protocols required. At times, experienced work crews needed to be quarantined and less experienced crews that required additional training were needed. The net result of these impacts was that the project could not be completed in 2020 as planned and construction efforts were delayed into the fall and winter period. This resulted in work being conducted when there were increased wind speeds and less favorable weather conditions, which limited the periods when workers were able to access the wind turbines to complete construction and commissioning activities. Winter conditions, including ice and snow, also slowed construction progress and turbine erection activities were halted during the winter period when high wind speeds and site access limitations due to snow and ice did not allow work to proceed.

Q. What steps did the Company take to mitigate the impact of the pandemic on the project and address the construction delays?

A. First and foremost, the Company worked with its contractors to implement recommended worker safety and public health protocols as that guidance became available to keep work crews healthy and limit transmission of the virus among and between work crews. New work methods were established to enable work to proceed while limiting the number of workers that needed to be physically proximate and to reduce mixing among the work crews. The Company also worked closely with the turbine supplier to track changing WTG production and shipping schedules so that adjustments could be made to match available labor and equipment on the project with available equipment deliveries. The construction sequencing was also changed to keep available work crews busy even though all of the equipment necessary to complete a WTG may not have been available at a particular turbine location. The Company also worked to increase construction efficiencies by using available equipment across the three wind projects in Wyoming (TB Flats, Ekola Flats, and Foote Creek I) that were using similar Vestas V136 WTG equipment in 2020 so that construction was not halted due to a lack of parts that were available at another project. The Company also worked with Vestas to evaluate changes to shipping and logistics plans to determine the most efficient means to advance the project.

Q. When was construction at the TB Flats Wind Project completed?

A. Turbine commissioning activities proceeded throughout the winter of 2020-2021 when weather conditions allowed, and significant construction progress resumed in the spring of 2021. Delivery of the final 28 WTGs to the project site was completed in May 2021 and turbine erection activities were able to continue as wind speeds dropped. Turbine erection and commissioning proceeded into the summer and the final WTGs at the project were placed into commercial operation on July 26, 2021.

Q. What are the final project costs associated with the TB Flats Wind Project?

A. The final project costs reflected in this filing are approximately $[redacted] million. This is slightly higher than the projected cost of $[redacted] million that was reflected and approved by the Commission in the 2021 Rate Case. The increase in forecasted costs is due to construction delays attributed to disruption in the worldwide supply chain caused by the coronavirus pandemic. This resulted in delay of project completion into 2021 and resulting project costs associated with that delay. These costs included higher costs associated with turbine supply, balance of plant construction, internal project management and construction oversight, capitalized property taxes, and higher Allowance for Funds Used During Construction costs, which were partially offset by savings on budgeted items. Ms. Sherona L. Cheung explains the revenue requirement treatment in the 2021 Rate Case and the Company's request in this application.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 399
Exhibit PAC/600
Witness: Richard A. Vail

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Richard A. Vail

March 2022

TABLE OF CONTENTS

ATTACHED EXHIBITS

Exhibit PAC/601—Goshen to Sugarmill to Rigby 161 kV Transmission Line Project

Exhibit PAC/602—Jordanelle to Midway 138 kV Transmission Line Project

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 Richard A. Vail. My business address is 825 NE Multnomah Street, Suite 1600, Portland, Oregon 97232. My present position is Vice President of Transmission. I am responsible for transmission system planning, customer generator interconnection requests and transmission service requests, regional transmission initiatives, capital budgeting for transmission, transmission and distribution project delivery, and administration of the Open Access Transmission Tariff (OATT).

Q. Please describe your education and professional experience.

A. I have a Bachelor of Science degree with Honors in Electrical Engineering with a focus in electric power systems from Portland State University. I have been Vice President of Transmission for PacifiCorp since December 2012. I was Director of Asset Management from 2007 to 2012. Before that position, I had management responsibility for a number of organizations in PacifiCorp's asset management group including capital planning, maintenance policy, maintenance planning, and investment planning since joining PacifiCorp in 2001.

II. PURPOSE OF TESTIMONY

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

A. The purpose of my testimony is to describe PacifiCorp's transmission system and the benefits it provides to Oregon customers. PacifiCorp's transmission system is designed to reliably transfer electric energy from a broad array of generation resources to load. PacifiCorp's interconnection to other balancing authority areas

(BAAs) and participation in the Energy Imbalance Market (EIM) provide access to markets and promote affordable and reliable service to PacifiCorp's customers. Further, all transmission system capacity increases provide benefits to customers by increasing reliability and allowing more generation to interconnect to serve customer load, as well as allowing PacifiCorp flexibility in designating generation resources for reserve capacity to comply with mandatory reliability standards.

I also specifically describe PacifiCorp's major capital investment projects for new transmission systems included in this rate case. My testimony demonstrates that the Company has made prudent decisions related to these projects and that these investments result in an immediate benefit to PacifiCorp's customers in Oregon. I recommend that the Public Utility Commission of Oregon (Commission) find these investments prudent and in the public interest.

III. OVERVIEW OF PACIFICORP'S TRANSMISSION SYSTEM AND INVESTMENT DRIVERS

Q. Please briefly describe PacifiCorp's transmission system.

A. PacifiCorp owns and operates approximately 17,700 miles of transmission lines ranging from 46 kilovolts (kV) to 500 kV across multiple western states. PacifiCorp has nearly two million customers with approximately 631,000 customers located in Oregon.

For convenience in load and resource planning, PacifiCorp groups its local area transmission and distribution system into load areas. These load areas are regions in which the PacifiCorp system is generally contiguous within the load area, while a set of transmission constraints and boundaries separate the load area from other portions of the PacifiCorp system. In Oregon, PacifiCorp generally has three primary load areas: Southern Oregon, Central Oregon, and the Willamette Valley. These primary load areas are further divided into 23 sub-areas within Oregon for planning purposes when evaluating the capability of the PacifiCorp system to meet the load and resource requirements of its customers.

Q. Please describe PacifiCorp's responsibility for maintaining reliability on its transmission system.

A. In 1996, the Federal Energy Regulatory Commission (FERC) issued Order No. 888,[1] which required that transmission system owners provide non-discriminatory access to their transmission systems. PacifiCorp is obligated under its OATT to plan its transmission system for the open access of all transmission customers. Through the OATT Attachment K local planning process and the FERC Order 1000 regional and inter-regional planning processes, PacifiCorp participates in open stakeholder planning processes covering its entire transmission footprint. These planning processes result in system plans that incorporate economics, reliability, and public policy inputs and requirements. PacifiCorp must also coordinate with other entities in the region for transmission planning purposes as required under FERC Order 1000.[2] In addition to these more general requirements, PacifiCorp also must comply with the specific requirements of the mandatory reliability standards approved by FERC.

[1] *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Pub. Util.; Recovery of Stranded Costs by Pub. Util. and Transmitting Utilities*, Order No. 888, 61 FR 21540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996), order on reh'g, Order No. 888-A, 62 FR 12274 (Mar. 14, 1997), FERC Stats. & Regs. ¶ 31,048 (1997), order on reh'g, Order No. 888-B, 81 FERC ¶ 61,248 (1997), order on reh'g, Order No. 888-C, 82 FERC ¶ 61,046 (1998).
[2] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Pub. Util.*, Order No. 1000, 76 FR 49842 (Aug. 11, 2011), FERC Stats. & Regs. ¶ 31,323 (2011), order on reh'g, Order No. 1000-A, 139 FERC ¶ 61,132 (2012), order on reh'g, Order No. 1000-B 141 FERC ¶ 61,044 (2012).

Q. Who establishes transmission reliability standards?

A. FERC directs the North American Electric Reliability Corporation (NERC) to develop reliability standards to ensure the safe and reliable operation of the Bulk Electric System (BES) in the United States in a variety of operating conditions. On April 1, 2005, NERC established a set of transmission operations reliability standards. A subset of the transmission reliability standards are the transmission planning standards (TPL Standards). The purpose of the TPL Standards is to "establish Transmission system planning performance requirements within the planning horizon to develop a BES that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies."[3] The TPL Standards, along with regional planning criteria (*i.e.*, regional planning criteria established by the Western Electricity Coordinating Council (WECC)) and utility-specific planning criteria, define the minimum transmission system requirements to safely and reliably serve customers.

Q. How does PacifiCorp ensure compliance with the TPL Standards?

A. The Company plans, designs, and operates its transmission system to meet or exceed NERC Standards for BES and WECC regional standards and criteria. To ensure compliance with applicable TPL Standards, PacifiCorp conducts an annual system assessment to evaluate the performance of the Company's transmission system and to identify system deficiencies. The annual system assessment is comprised of steady-

[3] *See* http://www.nerc.com/files/tpl-001-4.pdf.

state, stability, and short circuit analyses[4] to evaluate peak and off-peak load seasons in the near-term (one-, two-, and five-year) and long-term (10-year) planning horizons. The assessment is performed using power flow base cases maintained by WECC and developed in coordination among all transmission planning entities in the Western Interconnection. These base cases include load and resource forecasts along with planned transmission system changes for each of the future year cases and are intended to identify future system deficiencies to be mitigated.

As part of the annual system assessment, corrective action plans are developed to mitigate identified deficiencies, and may prescribe construction of transmission system reinforcement projects or, as applicable, adoption of new operating procedures. In certain instances, operating procedures prescribing action to change the configuration of the transmission system can prevent deficiencies from occurring when there are two back-to-back (N-1-1) (or concurrent) transmission system events. However, the use of operating procedure actions has limitations. In particular, actions taken in connection with operating procedures that are designed to protect the integrity of the larger integrated transmission system in the Western Interconnection of the United States can lead to large numbers of customers being at risk of an outage upon the occurrence of the second of two back-to-back (N-1-1) events. An effective corrective action plan is critical to ensuring system reliability so that large numbers of customers are not subjected to avoidable outage risk.

[4] Analyses consist of taking a normal system (N-0) and applying events (N-1, N-1-1, N-2, etc.) within each category (P0, P1, P2, P3, etc.) listed within the TPL Standards in order to identify system deficiencies. Example: An N-1-1 event describes two transmission system elements being out of service at the same time, but due to independent causes. An example of an N-1-1 event would be a planned outage of one 230 kV transmission line followed by an unplanned outage of any element in the system being used to continue service with the initial element out.

Q. Is compliance with the reliability standards optional?

A. No. The reliability standards are a federal requirement, subject to oversight and enforcement by WECC, NERC, and FERC. PacifiCorp is subject to compliance audits every three years and may be required to prove compliance during other NERC or WECC reliability initiatives or investigations. Failure to comply with the reliability standards could expose the Company to penalties of up to $1 million per day, per violation. Accordingly, and as described more fully later in my testimony, compliance with reliability standards is a major driver for the new capital investments in PacifiCorp's system transmission assets identified in and supported by my testimony.

Q. Please identify other drivers that are relevant to the capital investments in PacifiCorp's transmission system described in your testimony.

A. There are several other drivers that inform whether PacifiCorp will build new transmission facilities, including increased demand for transmission capacity, requests for transmission service, and the age and condition of existing transmission facilities. The specific drivers for the projects addressed in my testimony are described in more detail later in my testimony.

IV. OVERVIEW OF INVESTMENTS DESCRIBED IN TESTIMONY

Q. What specific transmission system investments are you addressing in your testimony?

A. My testimony addresses PacifiCorp's major new transmission system projects included in this general rate case filing. Specifically, my testimony addresses the following projects:

1. Goshen to Sugarmill to Rigby 161 kV Transmission Line Project

The Goshen to Sugarmill to Rigby 161 kV transmission line rebuild of an existing 69 kV line from Goshen substation to Sugarmill substation and then construction of a new 161 kV line from Sugarmill substation to Rigby substation located in the southeast Idaho area, as shown in the map attached in Exhibit PAC/601; and

2. Jordanelle to Midway 138 kV Transmission Line Project

The Jordanelle to Midway 138 kV transmission line project constructed nine miles of 138 kV transmission line between Midway and Jordanelle substations in Utah, as shown in the map attached in Exhibit PAC/602.

Q. **What are the projected costs associated with these transmission investments and their associated in-service dates?**

A. Table 1 identifies the specific projects and associated costs and in-service dates.

TABLE 1

Project	Total Company Cost ($m)	In-Service Date
Goshen-Sugarmill-Rigby 161kV Transmission Line Project	$23.2m	July 2022
Jordanelle-Midway 138kV Transmission Line Project	$21.9m	December 2021

These amounts include costs associated with engineering, project management, materials and equipment, construction, right-of-way (including rights acquired by condemnation), and an allowance for funds used during construction. These costs are also shown in the testimony and exhibits of Ms. Sherona L. Cheung. The in-service dates are based on the best available information at the time of preparing this case.

Q. Please briefly describe the benefits associated with these investments.

A. The benefits associated with these investments include increased load serving capability, enhanced reliability, conformance with NERC Reliability Standards, improved transfer capability within the existing system, relief of existing congestion, and interconnection and integration of new wind resources into PacifiCorp's transmission system. These benefits will be described more fully below.

Q. Will PacifiCorp's OATT transmission customers pay for some of these assets?

A. Yes, through OATT transmission charges. The Company's current transmission formula rate (included in PacifiCorp's OATT) was approved by FERC in Docket No. ER11-3643.[5] The Company's transmission formula rate is updated annually with the annual transmission revenue requirement (ATRR) that represents the annual total cost of providing firm transmission service over the test year. The ATRR calculation incorporates all transmission system investments by the Company, a return on rate base, income taxes, expenses, and certain revenue credits, among other specific elements and adjustments. Transmission assets, including new transmission capital, are included in the ATRR, weighted by months in service. The ATRR is converted into a rate by dividing the ATRR by firm transmission demand. All third-party revenues for transmission service (along with third-party revenues for ancillary services) are included as revenue credits in the calculation of rates in each of the Company's state retail jurisdictions.

[7] *In re PacifiCorp*, 143 FERC ¶ 61,162 (May 23, 2013) (letter order approving settlement agreement establishing formula rate).

Q. Please explain how network upgrade cost allocation works under the OATT.

A. In accordance with its OATT, when PacifiCorp receives a request for generation interconnection or transmission service, the Company completes studies to determine what new facilities or upgrades to existing facilities are required to accommodate the request. The studies identify the facilities and upgrades required and classify the asset additions required to support the service into two categories: direct assigned or network upgrade. Direct assigned assets are those assets that only benefit or are used solely by the customer requesting generator interconnection or transmission service. Those costs are directly assigned and paid for by that customer and will not be included in either the Company's ATRR or retail rate base. Network upgrades, on the other hand, are those assets that benefit all customers using the transmission system. Costs associated with network upgrades are investments by the transmission provider and are included in PacifiCorp's ATRR[6] and retail rate base.

V. GOSHEN TO SUGARMILL TO RIGBY 161 KV TRANSMISSION LINE PROJECT

Q. Please describe the investment for the Goshen to Sugarmill to Rigby 161 kV Transmission Line Project.

A. The Goshen to Sugarmill to Rigby 161 kV Transmission Line Project constructs approximately 44 miles of new transmission lines from the Goshen to Sugarmill and Sugarmill to Rigby substations located in the southeast Idaho area. Substation

[8] For generation interconnection customers, those customers may be required to pay the initial cost of network upgrades, subject to refund through credits to invoiced charges for transmission service and full refund of any remaining amounts after 20 years. *See* Section 11.4 of PacifiCorp's Standard Large Generator Interconnection Agreement (OATT Attachment N, Appendix 6 and available at http://www.oasis.oati.com/woa/docs/PPW/PPWdocs/20190601_OATTMASTER.pdf); *see also* Standardization of Generator Interconnection Agreements and Procedures, Order No. 2003-B, 109 FERC ¶ 61,287 (Dec. 20, 2004).

expansion will be required at Goshen, Sugarmill, and Rigby substations to accommodate the new 161 kV positions and associated structures and equipment, as shown on the map attached in Exhibit PAC/601. The project consists of two sequences of work. The first work sequence, completed in 2020, was to construct approximately 24 miles of the new Goshen to Sugarmill #2 161 kV transmission line and perform the required substation construction at Goshen and Sugarmill substations to terminate the new transmission line at both ends. This first work sequence was included and approved for recovery in the Company's last rate case proceeding, docket UE 374.[7]

The second work sequence consists of constructing approximately 20 miles of the new Sugarmill to Rigby #2 161 kV line and performing the required substation construction at Goshen and Sugarmill substations to terminate the new transmission line at both ends of the line.

As part of this project, PacifiCorp entered into a joint ownership agreement with Idaho Falls Power to construct 12 miles of new 161 kV shared transmission line from the corner of Lincoln Road and Hitt Road to Idaho Falls Power's future Paine Substation. Idaho Falls Power had much of this line already permitted and was able to secure final permits with the assistance of PacifiCorp while reducing time and costs required for PacifiCorp to secure permitting for a separate line. PacifiCorp will own and pay 51 percent of this line segment. Idaho Falls Power completed this portion of the line in December 2021. PacifiCorp expects to complete the line to Rigby substation by July 2022.

[7] *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).

Q. Please explain why this investment in the Goshen to Sugarmill to Rigby 161 kV Transmission Line Project is needed and beneficial.

A. The need for the Goshen to Sugarmill to Rigby 161 kV line was identified in the 2016 Goshen Area Planning Study to address projected overloads on the Goshen to Sugarmill 161 kV line and Goshen to Rigby 161 kV line, in addition to low voltage at Rigby and Sugarmill substations that manifest under heavy loading conditions. Projected peak summer load conditions in 2021 in the Rigby-Sugarmill area indicate that under normal operating conditions (N-0) the Goshen to Sugarmill 161 kV line was expected to load to 100 percent of its continuous rating of 201 megavolt amperes (MVA) and the Rigby and Sugarmill substations 161 kV bus voltage is expected to reach its minimum limit of 0.95 per unit. Additionally, the projected load growth exacerbates several existing N-1 conditions in the area. Based on 2021 load, loss of the Goshen to Sugarmill 161 kV line causes the Goshen to Rigby 161 kV line to overload to 179 percent of its four-hour emergency rating and can result in excessively low voltage down to 0.68 per unit in the Rigby-Sugarmill area. The loss of the Goshen to Rigby 161 kV line can cause the Goshen to Sugarmill 161 kV line to overload to 111 percent of its four-hour emergency rating of 255 MVA, overload to 102 percent of its 30-minute emergency rating of 279 MVA and can cause low voltage down to 0.88 per unit at Rigby substation. The Goshen to Sugarmill 161 kV line and Goshen to Rigby 161 kV line are operated radially during summer heavy loading periods to mitigate the risk of violating NERC Standard TPL-001-4 category P0 (N-0), P1 (N-1) and P6 (N-1-1) performance requirements due to transmission capacity deficiencies in the area. Operating radially puts approximately 150 megawatts (MW) of load at risk for N-1 loss of either the Goshen to Sugarmill 161 kV line or the Goshen to Rigby 161 kV line and 300 MW at risk for N-1-1 loss of any two transmission lines.

The new Goshen to Sugarmill to Rigby 161 kV line will increase load serving capacity in the Rigby to Sugarmill area by 250 MVA that will allow the transmission lines between Goshen, Sugarmill, and Rigby substations to operate in a normal loop configuration and eliminate N-1 thermal overload and low voltage issues on the remaining transmission line and substation. Benefits also include elimination of the N-0 overload risk, improved load service reliability under N-1 conditions, and resolution of most N-1-1 issues present in the area.

Q. Did PacifiCorp consider alternatives to investing in the Goshen to Sugarmill to Rigby 161 kV Transmission Line?

A. Yes. The first alternative in lieu of the Goshen to Sugarmill to Rigby 161 kV line that PacifiCorp considered was a project to construct a new approximately 35-mile-long Goshen to Rigby 345 kV line with 1272 aluminum conductor steel-reinforced (ACSR) cable and add a new 450 MVA capacity or larger 345/161 kV transformer at the Rigby substation. Work involved expanding both the Goshen and Rigby substation yards to accommodate the new facilities consisting of at least two 345 kV breakers at Goshen, one 345 kV breaker at Rigby and at least two 161 kV breakers at the Rigby 161 kV substation. This alternative was rejected since the estimated cost of the project was about $17.0 million higher than the chosen project to construct the new Goshen to Sugarmill to Rigby 161 kV transmission line. The alternative was estimated to be $57.7 million.

A second alternative considered was to construct an approximately 61-mile-long Antelope to Rigby 161 kV transmission line with 1272 ACSR cable or larger. Work involved expanding both the Antelope and Rigby substation yards to accommodate the new facilities consisting of at least two 161 kV breakers at Antelope and at least two 161 kV breakers at Rigby. A new 161 kV line from Antelope would provide a new source into the Rigby to Sugarmill area apart from Goshen substation; however, planning studies indicated that by adding the Antelope to Rigby 161 kV line, the N-1 loss of the Goshen to Sugarmill 161 kV line would still cause thermal overload and low voltage issues in the area and that load shedding and radialization of the Rigby to Sugarmill area would still be required. This alternative was rejected since the estimated cost of the project was about $8.0 million higher than the new Goshen to Sugarmill to Rigby 161 kV transmission line and that a new Antelope to Rigby 161 kV transmission line does not resolve the loading and voltage issues in the Rigby to Sugarmill area. The alternative was estimated to be $48.0 million.

A third alternative considered was to construct approximately 22.8 miles of a 161 kV transmission line from the Meadow Creek wind farm substation to Sugarmill and Rigby substations to create a looped transmission source back to Goshen substation. Work involved constructing approximately 5.9 miles of new single circuit 161 kV transmission line from Meadow Creek to a new tap location, using the existing right of way to construct 4.5 miles of double-circuit line from the new tap location to Sugarmill substation, and construct 12.4 miles of new single-circuit 161 kV line from the new tap location to Rigby substation. Work also included converting Meadow Creek's 161 kV substation yard into a new three breaker ring bus, installation of at least two 161 kV breakers at Sugarmill and Rigby substations, rebuilding the Goshen to Wolverine Creek to Jolly Hills to Meadow Creek 161 kV line with 1557 ACSR cable (approximately 32.4 miles), rebuilding the remaining three miles of 795 all-aluminum conductor (AAC) cable on the Goshen to Sugarmill 161 kV line, and adding a 161 kV bus tie breaker at Rigby to facilitate sectionalizing post N-1. Currently, the Goshen wind farms are radial from the Goshen 161 kV substation. Once looped through the Rigby and Sugarmill substations, a detailed voltage control study would be required to coordinate the wind farms and shunt devices in the area. Since the existing radial wind farm line is owned and operated by third parties, an agreement to use or buy the facilities would need to be negotiated. This alternative was rejected since the estimated cost of the project was about $8.2 million higher than the new Goshen to Sugarmill to Rigby 161 kV transmission line and required significant coordination with third parties to deliver the project. The alternative was estimated to be $48.5 million.

The last alternative considered was to loop the existing Goshen to Jefferson 161 kV transmission line in and out of the Bonneville substation. Work involved converting the Bonneville substation into a 161 kV breaker and one-half configuration, constructing an approximately 27-mile-long 161 kV line from Bonneville to Rigby substation with at least 1557 ACSR cable. Work also involved expanding both the Rigby substation yards to accommodate a new 161 kV line position consisting of at least two 161 kV breakers at the Rigby substation. Adding this new Bonneville to Rigby 161 kV line does not improve N-1 and N-1-1 issues in the area and therefore is not considered as a viable alternative. The estimate for this project was $33.2 million. Additional projects would be required to address the N-1 and N-1-1 issues. These projects include reconductoring 32 miles of Goshen to Rigby 161 kV line, reconductoring 16 miles of Sugarmill to Rigby 161 kV line, and reconductoring 3.5 miles of 795 AAC cable on existing Goshen to Sugarmill 161 kV line. Additionally, a new Goshen to Sugarmill 161 kV line would be required to mitigate the low voltage and voltage swings caused by the loss of the existing Goshen to Sugarmill 161 kV line. The estimate to reconductor these lines was $6.6 million and the estimate to construct a new Goshen to Sugarmill 161 kV line was $13.3 million. This alternative was rejected since the estimate for the new Bonneville to Rigby 161 kV line and supporting projects was about $12.7 million higher than the recommended new Goshen to Sugarmill to Rigby 161 kV transmission line project. The alternative was estimated to be $53.1 million.

VI. JORDANELLE TO MIDWAY 138 KV TRANSMISSION LINE PROJECT

Q. Please describe the investment for the Jordanelle to Midway 138 kV Transmission Line Project.

A. The Jordanelle to Midway 138 kV transmission line project constructed 9 miles of 138 kV transmission line between the Midway and Jordanelle substations in northwestern Wasatch County Utah. This project also included installation of two 138 kV breakers at Midway substation; the addition of 18 miles of optical ground wire between Hale and Midway substation; updates of the Naughton remedial action scheme (RAS); addition of a voltage transformer in Silver Creek and Hale substations; and protection and control upgrades at affected substations. The line siting partially followed Heber Light and Power's (HLP) existing 46 kV line across the Heber Valley. The structures are owned by PacifiCorp and, for portions, HLP will have circuits and other facilities attached to PacifiCorp structures. HLP's paid contributions in aid of construction for their facilities and Midway City's paid contribution for excess costs to underground a portion of the line.

Q. Please explain why this investment in the Jordanelle to Midway 138 kV Transmission Line Project is needed and beneficial.

A. In 2011, as part of ongoing contingency and growth studies it was identified that an outage of the Cottonwood to Snyderville 138 kV line creates a voltage collapse of the looped Summit and Wasatch County system when the area load is above 190 MW. The same outage creates voltage below the transmission voltage guideline of .90 when loading is above 175 MW. In 2020, the area was projected to be above 190 MW for 156 hours and above 175 MW for 620 hours. In addition, Utah Associated Municipal Power Systems (UAMPS) on behalf of HLP submitted a load forecast that put them above the system capability under N-1 conditions (loss of the Hale to Midway 138 kV line) by the year 2019 (approximately 42.9 MW of HLP load). At the time HLP was served at 46 kV from the Midway substation. An official request for a 138 kV delivery point was made. HLP plans to install a 138-46 kV transformer to provide redundancy to their 46 kV system and split HLP's 46 kV load between the two sources.

Q. Did PacifiCorp consider alternatives to investing in the Jordanelle to Midway 138 kV Transmission Line?

A. Yes, an alternative project was to construct a second 138 kV 19-mile line from Hale substation in Utah County to Midway substation and install a second Midway 138-46 kV 75 MVA transformer. Although a second line from Hale and second transformer at Midway would raise the system radialization limit to 225 MW, the 138 kV voltage at the Snyderville substation during the loss of the Cottonwood to Snyderville 138 kV line is the limiting factor. This alternative was rejected due to the estimated cost coming in higher than the preferred option and the resulting radialization limit was 20 MW lower than the preferred option. In addition, the construction and permitting of a new 138 kV line through Provo Canyon was deemed to be more difficult.

VII. CONCLUSION

Q. Please summarize your recommendation to the Commission.

A. I recommend that the Commission determine that the projects stated above will provide benefits to Oregon customers and are therefore prudent and in the public interest.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 399
Exhibit PAC/601
Witness: Richard A. Vail

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

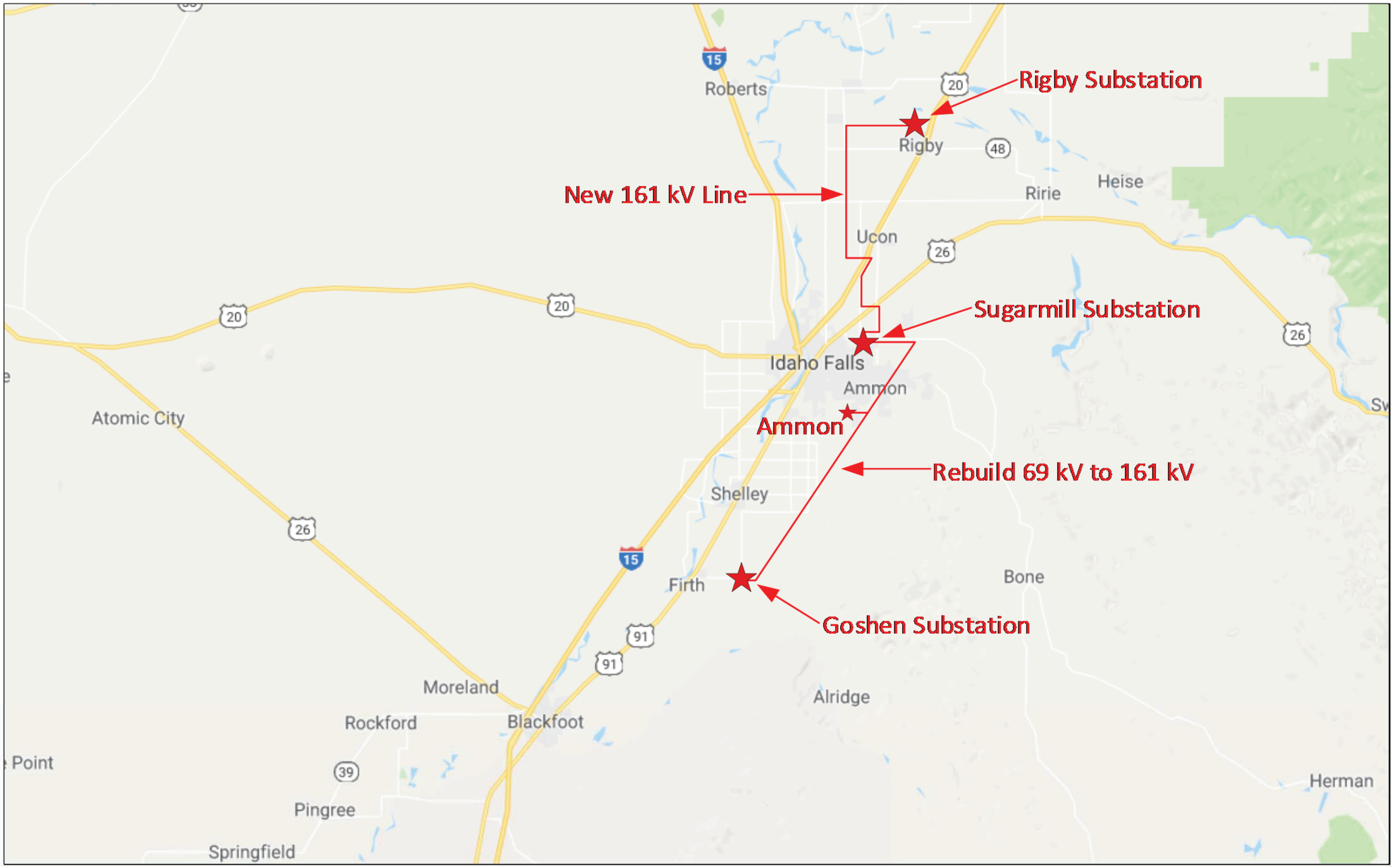
PACIFICORP

Exhibit Accompanying Direct Testimony of Richard A. Vail

Goshen to Sugarmill to Rigby 161 kV Transmission Line Project

March 2022

Goshen-Sugarmill-Rigby
161 KV Transmission Line Project Area



Docket No. UE 399
Exhibit PAC/602
Witness: Richard A. Vail

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

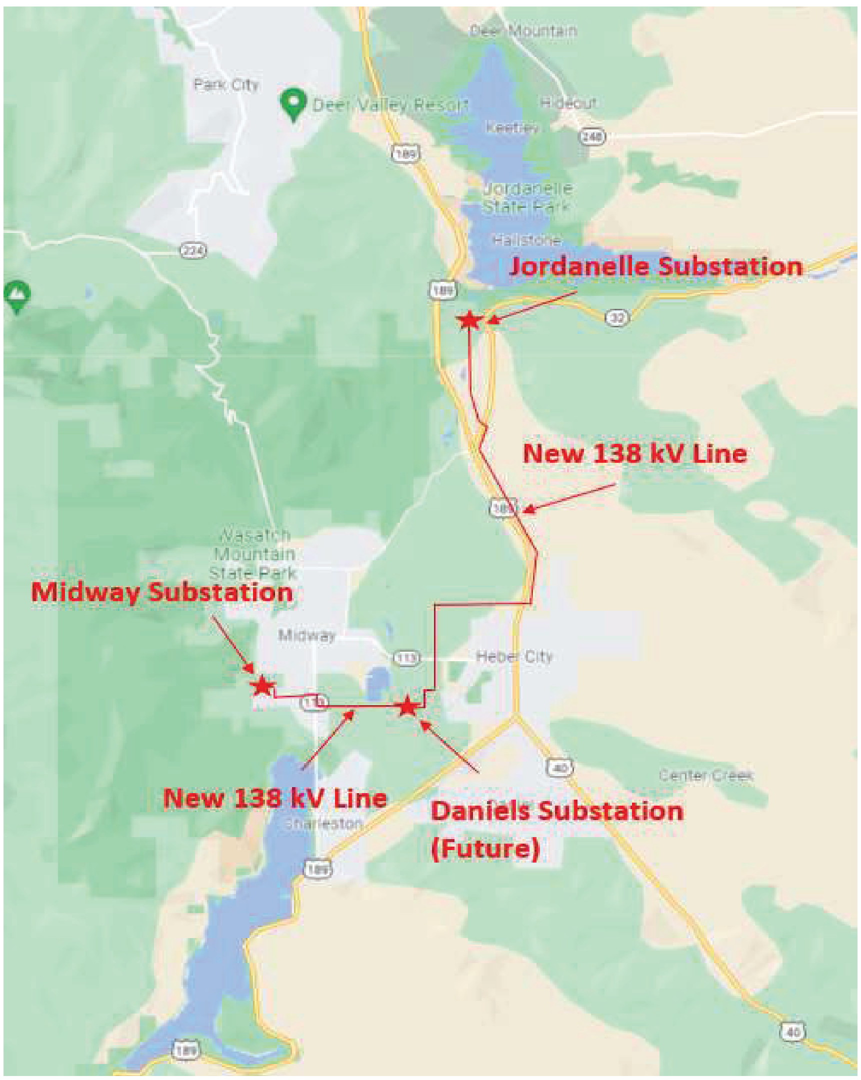
PACIFICORP

Exhibit Accompanying Direct Testimony of Richard A. Vail

Jordanelle to Midway 138 kV Transmission Line Project

March 2022

Jordanelle-Daniels-Midway
138 KV Transmission Line Project Area



Docket No. UE 399
Exhibit PAC/700
Witness: Allen Berreth

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Allen Berreth

March 2022

TABLE OF CONTENTS

ATTACHED EXHIBITS

Exhibit PAC/701—PacifiCorp Service Territory with FHCA

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 Allen Berreth. My business address is 825 NE Multnomah Street, Suite 1700, Portland, Oregon 97232. My present position is Vice President of Transmission and Distribution Operations for PacifiCorp. I am responsible for the departments that support the operations, maintenance, and construction of PacifiCorp's transmission and distribution systems; such as Asset Management, Investment Delivery, Finance, Real Estate, GIS, Facilities, Vegetation Management, and Wildfire Mitigation Planning.

Q. Briefly describe your education and professional experience.

A. I have a Bachelor of Science degree in Electrical Engineering with a focus in electric power systems from the University of Idaho and a Masters of Business Administration from Utah State University. I have been Vice President of Transmission and Distribution Operations since October 2020. Prior to my current position, I have held positions in delivery assurance, asset management, work planning, business improvement, and field engineering since joining PacifiCorp in 1998.

Q. Have you testified in previous regulatory proceedings?

A. Yes, I have testified previously in Washington.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe PacifiCorp's wildfire related transmission and distribution investments and vegetation management expenses included in this rate case. I support the Company's incremental investments in wildfire mitigation to address the risks posed by the increased frequency, severity, and costs of wildfires to customers, employees, and Company facilities. My testimony also supports an increase to baseline vegetation management spend due to cost escalations, and proposes changes to the Wildfire Mitigation and Vegetation Management Cost Recovery Mechanism (WMVM) to improve its effectiveness and functionality. I recommend that the Commission approve these new investments and proposed changes as prudent and in the public interest.

III. BACKGROUND ON WILDFIRE RISK IN OREGON

Q. How have the risks associated with wildfires evolved in PacifiCorp's service territories?

A. There has always been some degree of wildfire risk across PacifiCorp's service territories, including in Oregon. This risk is inherent to operating an electric utility and is elevated for utilities in the Western United States where climates are arid year-long in some areas, or seasonally in others. However, the frequency, severity, and costs of catastrophic wildfires are increasing across the West. Recent experiences with catastrophic and tragic wildfires have resulted in an even greater focus on wildfire risk mitigation by public utilities in the region.

Q. Please describe Senate Bill (SB) 762 and the Wildfire Protection Plans (WPPs).

A. On July 19, 2021, Governor Brown signed SB 762 into law. SB 762 requires that public utilities file with the Commission risk-based WPPs that include means for mitigating wildfire risk, balancing costs with the resulting reduction of risk, and preventive actions and programs to minimize risk of utility facilities causing a wildfire.[1] This law allows for recovery of all reasonable costs and prudent investments made by a public utility to implement a WPP and also allows for the recovery of those costs through an automatic adjustment clause.[2] PacifiCorp filed its WPP on December 30, 2021.

Q. What are the elements of the WPP?

A. PacifiCorp is adapting to the changes in wildfire risk through adoption of accelerated and enhanced wildfire mitigation measures that conform with Oregon legislation, including SB 762, for utility wildfire mitigation. PacifiCorp identified key goals to help inform its wildfire mitigation approach: 1) minimize the risk of wildfires from PacifiCorp equipment; 2) promptly address any problems attributed to PacifiCorp equipment if they do occur; 3) be prepared to address wildfires from other sources; and 4) respond when a wildfire puts utility equipment at risk. PacifiCorp took these goals and engaged in an extensive modeling process to develop a risk-based approach to achieving them. This risk-based approach facilitates smart investments targeted to places on PacifiCorp's system where they will have the most impact and ensures that PacifiCorp's human capital is also deployed in areas where they will have the greatest impact. These targeted investments are incremental to PacifiCorp's investment in the ordinary course of its business and will meaningfully reduce the wildfire risk on the Company's system.

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[1] *See* ORS 757.963.
[2] ORS 757.963(8).

Q. Please describe how the risk of wildfire has been modeled in PacifiCorp's service territory.

A. PacifiCorp recognizes that if certain weather and fuel conditions are present, a disruption of normal operations on the electrical network, called a "fault", can result in the ignition of a fire. Under certain weather conditions and in the vicinity of wildland fuels, such an ignition can grow into a harmful wildfire, potentially even growing into a catastrophic wildfire causing great harm to people and property. PacifiCorp's risk analysis reviews fire history, the recorded causes of the fires, the acreage impact of the fires, and when in the year the fires typically occur. Using that information, the risk analysis identifies the logic for a risk-informed method to strategically address utility wildfire risks. PacifiCorp patterned its wildfire risk modeling on the methodology developed after a long and iterative process in California. To take advantage of the experience learned through that process, PacifiCorp engaged REAX Engineering Inc., a fire-science engineering firm, to identify areas of elevated wildfire risk, designated as Fire High Consequence Areas (FHCA).

The data and process used in PacifiCorp's analysis are as follows:

1) Topography of the land, including elevation, slope, and aspect;
2) Fuel data which quantify fuel loading, fuel particle size, and other quantities needed by fire models to calculate the rate of spread;
3) Weather Research and Forecasting, which is a hybrid of weather modeling and surface weather observations (including temperature, relative humidity, wind speed/direction, and precipitation);

4) Historical fire weather days spanning the period from January 1, 1979, through December 31, 2017;

5) Estimated live fuel moisture;

6) Ignition modeling, using Monte Carlo simulated ignition scenarios; and

7) Fire spread modeling.

In addition, potential impact was considered by factoring population density. In general, if population density did not correlate to fuel and fire weather history, an area would not be considered a candidate for FHCA designation. A final confirmation exercise was completed by evaluating the FHCA against historical fire perimeters (which are the final recorded footprint for any given fire), existing Company facility equipment, and the Company's service territories. The resulting FHCA and PacifiCorp's service territories are shown in Exhibit PAC/701.

Q. Based on this wildfire risk modeling, what components of PacifiCorp's system have been identified as existing in a FHCA?

A. Based on the wildfire risk modeling conducted in PacifiCorp's service area, a large portion of PacifiCorp's service territory in southern Oregon, northern California and parts of Washington and Utah are identified as having sections inside the FHCA and are candidates for wildfire mitigation project investments.

IV. WILDFIRE MITIGATION CAPITAL COSTS

Q. What are the planned capital costs for the wildfire mitigation projects in 2021 and 2022?

A. Table 1 below describes the specific wildfire mitigation capital costs by breakdown of activity.

Table 1: Wildfire Mitigation System Hardening Program Capital Costs*

Investment Category	Mitigation Program(s) Included	Description of Program	Purpose/Risk Being Mitigated	Planned Capital Costs through 2022
Oregon Distribution	System Hardening: Line Rebuild	Distribution line rebuilds including all or parts of the following: installation of covered conductor, transition to underground, pole replacements, and conductor replacements	Reduce equipment failure that may ignite a wildfire along with increased resiliency to a wildfire occurrence	$27,237,149
	System Hardening: Advanced Protection & Control	Replace electro-mechanical relays protecting distribution lines in FHCA with modern microprocessor relays that provide more accurate data and faster relaying	Increasing ability to locate where a fault occurred on a line which could result in increased patrol time	
	System Hardening: Pole mounted overcurrent and overvoltage protection replacement	Replacement of fuses, lightning arrestors and cutouts throughout the FHCA with non-expulsion type equipment	Reduce equipment failure that may ignite a wildfire along with increased resiliency to a wildfire occurrence	
Transmission	System Hardening: Line Rebuild	Transmission line rebuilds including all or parts of the following: installation of covered conductor, tree wire, pole replacement, and conductor replacements	Reduce equipment failure that may ignite a wildfire along with increased resiliency to a wildfire occurrence	$7,443,032
Oregon Situs	Situational Awareness	Invest in tools, software, and hardware to incorporate real time weather data, implement a risk forecasting and impact-based fire weather model, and inform key decision making and protocols.	Develop a dynamic risk assessment tool to inform investment scenarios, initiative prioritization, and overall decision making to manage risk	$1,700,000[3]
Total				$36,380,181

*Transmission costs provided reflect the Oregon allocation of total-company costs.

[3] Capital investment in situational awareness will be recovered through the deferral accounting requested in the Company's application in Docket No. UM 2221 instead of this general rate case filing.

I discuss these mitigation programs included in system hardening and situational awareness in more detail below.

A. System Hardening

Q. Please explain what system hardening is in the context of the Company's wildfire mitigation efforts.

A. System hardening is an engineered response to an identified risk to the electrical system. System hardening includes retrofitting specific devices or components within the system to make it more resilient and may also include the wholesale replacement of legacy equipment when retrofitting is not a viable solution. I will describe some of the system hardening that PacifiCorp is and will be engaging in to mitigate wildfire risks in more detail below.

Q. How do these system hardening projects reduce the threat of wildfire?

A. PacifiCorp's system hardening projects focus on reducing the potential that the power system is the source of ignition by creating a spark during a fault event. A significant ignition driver on electrical systems is contact from foreign objects (trees, wildlife, mylar balloons, etc.) that can result in high-energy and high-temperature arcing between two conductors or between one conductor and the ground.

Q. What hardening efforts on distribution systems reduce potential ignitions?

A. All of the Company's wildfire mitigation programs applied to distribution systems work to either prevent ignitions or control the potential events to limit overall impact. The key programs included in system hardening of distribution systems include the line rebuild project, implementation of advanced protection and control schemes through equipment upgrades, and the replacement of pole mounted overcurrent and overvoltage protection equipment such as expulsion fuses.

B. Line Rebuild Program

Q. Please explain what the line rebuild program is in the context of wildfire mitigation.

A. A key hardening effort for wildfire mitigation is the line rebuild program where targeted lines or portions of lines are either moved, removed, transitioned to underground, or retrofitted with more resilient materials such as covered conductor to mitigate the risk of contact related faults on overhead conductor. Currently, the majority of the program includes retrofitting existing lines with covered conductor. Covered conductor, unlike bare conductor, is designed to withstand incidental contact with vegetation, other debris, and even the ground in a wire down event. The program will involve more than replacing existing bare conductor with covered conductor. Poles will be replaced as necessary based on loading assessments of existing poles where covered conductor is to be installed. This is because covered conductor is heavier than bare conductor and, under the combination of ice and wind, has a larger diameter which results in further additional pole loading. A secondary benefit to covered conductor is an improvement in reliability. In certain applications standard pole mounted overcurrent and overvoltage protection equipment, such as fuses, lightning arrestors, and cutouts, will be replaced within the FHCA with non-expulsion type equipment to eliminate any melted fuse material from falling to the ground when operated.

Q. Is it standard practice for PacifiCorp to install covered conductor, non-expulsion fuses, or composite material distribution poles?

A. No. Standard overhead circuit construction uses bare conductor and wood poles that balance safety, reliability, and costs. The installation of covered conductor, non-expulsion fuses, and composite material poles are in direct response to increased wildfire risk and are specifically designed to accelerate and improve mitigation of catastrophic wildfires associated with PacifiCorp's system.

Q. How do transmission line rebuilds help mitigate and protect against wildfire risk?

A. Rebuilding transmission lines helps to reduce equipment failures and incidental contacts that pose a risk of wildfire ignition. Such equipment failures, while infrequent occurrences, could result in substantial arc energy that can result in wildfire ignition. Due to the cross-country nature of many portions of PacifiCorp's system (particularly on the local transmission network) the risk of ignition sources is heightened. For example, in Oregon, trees outside of the vegetation managed corridors that are particularly tall, or located on slopes, result in increased risk of fall-in contacts. Rebuilding transmission lines in areas where this risk is heightened allows PacifiCorp to install covered conductor and improve structures. Respectively, such measures will reduce the probability of a fault event and improve resiliency to the extent rebuilt structures can better withstand localized wildfire events.

Q. What criteria did the Company use to select areas in the FHCA to replace existing conductor with covered conductor?

A. PacifiCorp targeted areas within the FHCA to determine what areas in its system were at elevated risk based on proximity to population centers, historic weather patterns, and vegetation. Covered conductor was selected for use where there is risk of incidental contacts, such as large branches or trees striking the phase conductors.

Q. Are there reliable measurements or metrics the Company can use to determine how successful the use of covered conductor is in mitigating wildfire risks over time?

A. Yes, although such measurements will not be immediately informative. Over time, the Company anticipates that comparisons of fault rates resulting from incidental tree contacts for the areas where covered conductor is employed versus the same areas before replacement with the covered conductor will demonstrate the effectiveness of this measure.

Q. What kind of monitoring does the Company plan to use to ensure that the use of covered conductor is meeting expectations in the absence of such metrics?

A. As noted in my response to the preceding question, the Company will track fault rates resulting from incidental tree contacts on rebuilt sections. This information will enable the Company to compare faults both before and after installation of covered conductor to better understand how successful it has been in mitigating wildfire risks over time. Unfortunately, the data needed to quantitatively provide useful metrics for such a comparison will not be available for several years.

C. Advanced Protection and Control

Q. Please explain what advanced protection and control measures are in the context of wildfire mitigation.

A. Advanced protection involves the deployment of sophisticated protection control strategies, particularly advanced relay technologies on distribution and transmission lines. In the context of wildfire risk mitigation, these protection control strategies involve the device operations that take place when fault events occur. In contrast to the wildfire mitigation strategies discussed above, which relate to limiting the occurrence of fault events, advanced protection and control strategies relate to limiting the length and magnitude of a fault event. Specifically, the window of time after fault events represents the time when electrical system facilities pose the highest risk of igniting adjacent fuel, which could result in a wildfire. Reducing the time between when a fault occurs and that fault condition is cleared may reduce the risk of igniting adjacent fuel.

Q. Please describe the differences between legacy electro-mechanical relays and modern microprocessor relays.

A. Unlike an electro-mechanical relay, microprocessor relays are able to exercise programmed functions nearly immediately (near the speed of light), which results in much faster device response during fault conditions. Microprocessor relays also allow for greater customization to address environmental conditions through multiple settings groups; they are also better able to incorporate complex logic to execute specific operations. Also, in contrast to electro-mechanical relays, microprocessor relays retain event logs that provide data for fault location and later analysis.

Q. Will these modern microprocessor relays provide the Company more data regarding line contacts and other faults on the system than the electro-mechanical relays currently used on PacifiCorp's system?

A. Yes. These new relays will capture a variety of event logs, including waveforms during fault events.

Q. How will the additional data provided by these new relays help the Company in its wildfire mitigation efforts?

A. In addition to faster fault clearing schemes, these relays improve response times since they can identify locations where disturbances emanate from, which will be used by field and office teams to assess these situations. PacifiCorp will also use this data during investigations of events to ensure that the devices performed consistent with the programmed settings and to evaluate other wildfire mitigation technologies.

D. Replacement of Pole Mounted Overcurrent and Overvoltage Protection Equipment

Q. Please explain what the replacement of pole mounted overcurrent and overvoltage protection equipment means in the context of wildfire mitigation.

A. The replacement of pole mounted overcurrent and overvoltage protection equipment includes the proactive replacement of all expulsion type fuses, lightning arrestors, and cutouts in the FHCA.

Q. Is it standard practice to use non-expulsion type fuses and lightning arrestors?

A. No. Non-expulsion type fuses and lightning arrestors are not standard practice.

Q. How does the replacement of expulsion type fuses and lightning arrestors help mitigate and protect against wildfire risk

A. Overhead expulsion fuses serve as one of the primary system protection devices on the overhead system. The expulsion fuse has a small metal element within the fuse body that is designed to melt when excessive current passes through the fuse body, interrupting the flow of electricity to the downstream distribution system. Under certain conditions, the melting action and interruption technique will expel an arc out of the bottom of the fuse tab. To reduce the potential for ignition as a result of fuse operation, PacifiCorp has identified alternate methodologies and equipment that do not expel an arc for installation within the FHCA.

E. Situational Awareness

Q. Please explain what situational awareness is in the context of the Company's wildfire mitigation efforts.

A. Having a sophisticated, dynamic risk model grounded in situational awareness is pertinent to ensure electric utilities know when, where, how, and why to take action to mitigate the risk of wildfire. PacifiCorp's approach to situational awareness includes the acquisition of data to run real time, daily simulations, forecast and assess the risk of potential or active events to inform operational strategies, response to local conditions, and influence decision making. Decision making could include the implementation of augmented protection and control schemes or activation of additional resources for supplemental patrols to assess local conditions.

Q. What key investments need to be made to support this approach toward situational awareness?

A. To support the development of a robust, repeatable, dynamic risk assessment tool, a combination of investments must be made including the acquisition of data, collection of company owned data through new devices, storage and processing of data, and mapping or visualization of data into dashboards and tools. Software, hardware, data storage, data management, and data processing tools must be purchased to move forward an enterprise type solution with built in redundancy.

Q. What capital expenditures overall will the Company make through 2022 with respect to system hardening and situational awareness?

A. As shown in Table 1, through 2022, PacifiCorp will make capital expenditures of approximately $27,237,149 in its Oregon distribution system and $7,443,032 Oregon-allocated in its transmission system on system hardening. The additional situational awareness investment of $1,700,000 (Oregon allocated) is not included in this filing and will be recovered through the Company's WPP deferral request in docket UM 2221.

Q. Please describe the benefits of PacifiCorp's wildfire mitigation investments.

A. Proactively investing in wildfire mitigation projects in identified FHCAs reduces the risk of catastrophic fire caused by PacifiCorp's facilities, directly benefiting PacifiCorp customers. In addition, reducing the risk of catastrophic fire benefits fire response agencies, preserves customer property and Company facilities, and minimizes the cost of rebuilding.

Q. How do PacifiCorp's wildfire mitigation efforts relate to the Company's standard safety and compliance activities?

A. Many of the wildfire mitigation strategies I discuss above go beyond standard utility practice. For example, PacifiCorp does not, in the normal course, install covered conductor. These measures are in direct response to changing best practices for mitigating wildfire and are incremental to work PacifiCorp would do in the ordinary course of its business. Similarly, activities such as replacement of existing equipment (replacing distribution poles with composite material poles, replacing electro-mechanical relays, etc.) are now informed by the potential for the replacement to mitigate wildfire risk, location of the existing equipment within FHCA, and may involve accelerated replacements.

V. WILDFIRE MITIGATION INCREMENTAL EXPENSE

Q. Are the capital investments described above the only type of investments being made in Oregon to mitigate wildfire risk?

A. No. As mentioned above, PacifiCorp filed its first WPP on December 30, 2021. This plan reflects a comprehensive approach to mitigating the risk of wildfires and includes increased capital investment as well as operating expense to move forward critical maintenance programs. Table 2 below describes the specific incremental wildfire mitigation expense planned in 2023 by breakdown of activity due to an increase in scope above legacy programs.

Table 2: Wildfire Mitigation System Hardening Program Incremental Annual Expense

Investment Category	Programs / Incremental Scope Included	2023 Planned Spend Total Co. ($)[4]	2023 Planned Spend OR Alloc. ($)
WMP Transmission (Non-Vegetation Management)	• Annual asset inspections in the FHCA • Annual Enhanced Inspections (Infrared) inspections in the FHCA	$148,000	$38,584
WMP Distribution (Non-Vegetation Management)	• Annual asset inspections in the FHCA • Transition from a 10-yr to a 5-yr detail inspection cycle in the FHCA (100% increase in annual detailed inspections) • Situational awareness (Described above in testimony) • Stakeholder and community engagement • Plan monitoring	$4,207,676	$4,207,676
WMP Vegetation Management - Transmission	• Annual vegetation management inspections in the FHCA • Implementation of new maintenance cycles	$470,636	$124,261
WMP Vegetation Management - Distribution[5]	• Annual vegetation management inspections in the FHCA • Radial pole clearing of subject poles in the FHCA • Implementation of new maintenance cycles	$15,289,309	$15,289,309
TOTAL		**$20,121,621**	**$19,659,830**

A. Asset Inspections

Q. How do asset inspections mitigate wildfire risk?

A. Inspection and correction programs are the cornerstone of a resilient system. These programs are tailored to identify conditions that could result in premature failure or potential fault scenarios, including situations in which the infrastructure may no

[4] Planned incremental wildfire mitigation spend in this table includes Oregon's allocation only but reflects the same planned spend and programs included in PacifiCorp's 2022 WPP.
[5] This spend is not due to escalation of existing vegetation management costs but is incremental spend due to increased scope and activities.

longer be able to operate per code or engineered design, or may become susceptible to external factors, such as weather conditions. The existing inspection and correction programs are effective at maintaining regulatory compliance and managing routine operational risk. They also mitigate some wildfire risk by identifying and correcting conditions which, if uncorrected, could potentially ignite a fire. Recognizing the growing risk of wildfire, PacifiCorp is supplementing its existing programs to further mitigate the growing wildfire specific operational risks and create greater resiliency against wildfires. These changes are meant to increase the frequency of inspections or how assets are inspected to accelerate identification and correction of conditions.

Q. What are these specific changes?

A. PacifiCorp's asset inspection program involves three primary types of inspections: (1) visual assurance inspection; (2) detailed inspection, and (3) pole test & treat. Legacy inspection cycles, which dictate the frequency of inspections, are set by PacifiCorp asset management to align with state specific compliance requirements. In general, visual assurance inspections are conducted more frequently, to quickly identify any obvious damage or defects that could affect safety or reliability. Detailed inspections have a more detailed scope of work, so they are performed less frequently than visual assurance inspections. The frequency of pole test & treat is based on the age of wood poles, and such inspections are typically scheduled in conjunction with certain detailed inspections. Regarding distribution, PacifiCorp is proposing to move from a two-year cycle to an annual frequency for visual assurance inspection in the FHCA and from a 10-year cycle to a five-year cycle for detailed inspections in the

FHCA, effectively increasing the number of each type of inspection annually in the FHCA by 100 percent over legacy programs. PacifiCorp also plans to introduce new, annual enhanced inspections annually on overhead transmission in the FHCA.

Q. What are enhanced inspections?

A. PacifiCorp's enhanced inspection utilizes alternate technologies to identify hot spots, equipment degradation, and potentially substandard connections that are not detectable through a visual inspection. Infrared data is gathered using a helicopter flying over the designated lines within the FHCA near peak loading intervals and is performed incrementally to existing inspection programs.

Q. How do these enhanced inspections mitigate wildfire risk?

A. Hot spots on power lines identified through infrared data gathering can be indicative of loose connections, deterioration, and/or potential future fault locations. Therefore, identification and removal of hot spots on overhead transmission lines can prevent further deterioration, reduce the potential for equipment failure and faults, and reduce ignition probability related to equipment failure.

Q. Are asset inspections the only proposed change to mitigate wildfire risk?

A. No. PacifiCorp is also proposing enhancing programs in the areas of situational awareness, which is already described above in my testimony, stakeholder and community engagement, plan monitoring, and vegetation management.

B. Stakeholder and Community Engagement

Q. What is stakeholder and community engagement in the context of wildfire mitigation?

A. PacifiCorp plans to employ a multi-pronged approach for community engagement and outreach with the goal of providing clear, actionable, and timely information to customers, community stakeholders, public safety partners, and regulators. Over the past several years, the Company has engaged customers and the general public on the topic of wildfire safety and preparedness through a variety of tactics and intends to continue enhancing this outreach including webinars, in-person forums, targeted paid media campaigns, press engagement, distributed print materials, social media updates, and communication through owned channels such as bill messages and website content, among others. Regarding coordination with public safety partners, PacifiCorp plans to continue implementing tabletop and function exercises to enhanced collaboration and prepare for emergencies.

Overall, the wildfire safety and preparedness community and stakeholder engagement plan will continue to mature year-over-year as additional feedback and regulatory guidance is incorporated to broaden engagement and outreach outside of traditional engagement methods.

C. Plan Monitoring

Q. How does incremental plan monitoring reduce the risk of wildfires?

A. As previously stated in my testimony, PacifiCorp's WPP reflects a comprehensive approach to mitigating the risk of wildfires and impacts many programs and departments across the Company. To successfully deliver the plan and obtain the plan objectives of reducing wildfire risk, additional resources are needed to develop, implement, and monitor the plan and the various programs or projects included. Specific examples include meteorologists, emergency managers, program managers, program controllers, and analysts to name a few. These key resources are critical to ensuring the timely and quality completion of the program elements such as community outreach, public safety partner coordination and planning, situational awareness, asset inspections, and vegetation management.

D. Wildfire Mitigation Vegetation Management

Q. How does vegetation management relate to reducing wildfire risks?

A. Vegetation management is generally recognized as a significant strategy in any WPP. Vegetation contacting a power line is a potential source of fire ignition. Thus, reducing vegetation contacts reduces the potential of an ignition originating from electrical facilities. While it is impossible to eliminate vegetation contacts completely, at least without radically altering the landscape near power lines, a primary objective of PacifiCorp's existing vegetation management program is to minimize contact between vegetation and power lines by addressing grow-in and fall-in risks. This objective is in alignment with core WPP efforts, and continuing dedication to administering existing programs is a solid foundation for PacifiCorp's WPP efforts. To supplement the existing program, PacifiCorp vegetation management is implementing additional WPP strategies in Oregon.

Q. What are these strategies being implemented?

A. The focus of PacifiCorp's vegetation management efforts generally includes pruning and tree removals. PacifiCorp prunes trees to maintain a safe distance between tree limbs and power lines. PacifiCorp also removes trees that pose an elevated risk of falling into a power line. In Oregon, this has traditionally been completed on distribution facilities with a four-year cycle. To address the growing risk of wildfires in Oregon, PacifiCorp plans to transition to a three-year cycle for all vegetation management work.

In addition to the transition to a three-year cycle discussed above, PacifiCorp's vegetation management specifically targets risk reduction in the FHCA with three distinct strategies. First, PacifiCorp vegetation management will conduct annual vegetation inspections on all lines in the FHCA, with correction work also completed based on inspection results. Second, PacifiCorp will use increased minimum clearance distances for distribution cycle work completed in the FHCA. Third, PacifiCorp plans to complete annual pole clearing on subject equipment poles located in the FHCA.

Q. How does this compare to PacifiCorp's existing or legacy vegetation management program?

A. Prior to the development of the WPP, PacifiCorp already had a vegetation management program in place. While the legacy program contained similar elements and objectives to the strategies just described, the incremental efforts reflect a shift change in strategy and the costs reflect the incremental spend needed to accomplish the new tasks and work to meet the objectives of the increase in scope. As such, it should be viewed as incremental to baseline or legacy vegetation management programs.

Q. How is PacifiCorp proposing to change that mechanism in light of the recently passed legislation on WPPs?

A. As discussed below, PacifiCorp is proposing to modify that mechanism so it will only cover vegetation management costs. PacifiCorp will not recover future wildfire mitigation costs through that mechanism, but instead will propose a new mechanism in the future consistent with the requirements of SB 762 for the recovery of those costs. Please refer to the testimony of Company witness Ms. Joelle R. Steward for a more detailed explanation of SB 762 and the changes to the WMVM.

VI. VEGETATION MANAGEMENT

A. Increases in Baseline Vegetation Management Costs

Q. Is PacifiCorp proposing an increase in baseline vegetation management costs?

A. Yes. Additional spending has been identified for the legacy vegetation management due to cost escalation and change in program activities. Different than the wildfire mitigation spending, which reflects an increase in scope to accomplish additional work within the FHCAs and reduce the risk of wildfire, this spend has been identified due to the increase in costs experienced to accomplish the core work of the program, including the shift to a three-year cycle. PacifiCorp's forecast costs in this case reflect updates to the expenses PacifiCorp has seen over the past year to meet its vegetation management goals and reflect the ongoing cost to implement PacifiCorp's vegetation management program outside the scope of the wildfire mitigation spending covered under SB 762 implementation.

Q. Can you provide some examples of what is driving the increased costs for PacifiCorp's vegetation program?

A. Similar to the wildfire vegetation management discussion above, the focus of PacifiCorp's vegetation management efforts generally includes pruning and tree removals. PacifiCorp prunes trees to maintain a safe distance between tree limbs and power lines. PacifiCorp also removes trees that pose an elevated risk of falling into a power line. In Oregon, this has traditionally been completed on distribution facilities with a four-year cycle. To address the growing risk of wildfires in Oregon, PacifiCorp plans to transition to a three-year cycle for all vegetation management work. The volume of tree removals that pose an elevated risk of falling into a power line has also increased in recent years, which has increased the associated costs. In addition, increased labor costs have also been experienced as the market for vegetation management workers has become more competitive. This has not only increased the base labor costs for the vegetation management program as a whole but has also increased costs for labor premiums to attract additional travel crews to the area.

Q. What is the impact of these increased costs on the operation and maintenance (O&M) included for vegetation management in base rates?

A. PacifiCorp is proposing to increase baseline O&M for vegetation management from $30 million to $50 million.

Q. Despite this cost increase, what steps is the Company taking to control costs while still achieving the goals of the program?

A. PacifiCorp is implementing two strategies for cost control and delivering on the goals of the vegetation management program as described above. The first strategy is increasing the number of internal company foresters that coordinate the vegetation management activity within a geographic area. This will increase oversight of both program efficiencies and deliverables. The second strategy is implementing an internal vegetation management audit team that will bolster the quality assurance reviews of the program. This will also help drive program performance in terms of productivity, efficiency, and cost of program deliverables.

B. Changes to the WMVM

Q. Please describe the WMVM that was approved in PacifiCorp's last general rate case as it relates to wildfire mitigation.

A. The WMVM provides for the possible recovery of prudent wildfire mitigation and vegetation management costs between rate cases through a separate recovery mechanism. Under the mechanism, PacifiCorp would be allowed to recover up to $6.6 million in wildfire mitigation and vegetation management costs over what was included in base rates based on the number of probable violations identified in the subsequent years vegetation audit and the company's earnings. The audit would cover all of PacifiCorp's Oregon system, not just those lines that were worked the year before, or since the mechanism was created. PacifiCorp would have to have fewer than 75 probable violations in the subsequent year audit to recover its costs, unless the Company is significantly underearning. PacifiCorp, however, could recover expenses above the incremental $6.6 million based on a less restrictive earnings test and larger violation criteria.

Q. Is PacifiCorp proposing changes to the WMVM?

A. Yes, PacifiCorp is proposing revisions to improve the operation of the WMVM with regards to vegetation management. There are two main reasons behind PacifiCorp's proposal. First, the WMVM needs to be revised to address the recent wildfire legislation, SB 762. PacifiCorp has separately sought to defer costs for activities addressed in the Company's WPP, and will seek to recover those costs through an automatic adjustment clause, in line with the language in the statute providing for recovery of all costs incurred by the utility. This modification is discussed by Ms. Steward in her testimony. Second, the WMVM, as currently configured, only allows PacifiCorp to recover all of its costs if it either spends only up to what is included in base rates or spends an enormous amount to send crews to every line every year to ensure there are less than 75 probable violations found in the audit the following year. Neither option is in the interest of customers because limiting spending does not promote reliability and spending the amounts required to trim every line-mile every year increases rates unnecessarily. Accordingly, PacifiCorp proposes changes to incentivize incremental spending to promote a robust vegetation management program and provide for recovery of larger increases in spending if they provide significant reductions in violations.

Q. Is PacifiCorp proposing other revisions to the WMVM, beyond the structural changes discussed above?

A. Yes, PacifiCorp is proposing four changes to improve the efficiency and functioning of this mechanism:

1) Modification of the violation criteria for the level of violations.

2) Modification of the Safety Staff audit to verifiable violations on lines trimmed within two years.

3) Modification of the basis point penalty to a sharing percentage.

4) Full recovery of costs due to inflation and new regulatory mandates.

Q. Why is PacifiCorp proposing to modify the violation criteria for the level of the violations?

A. In reviewing the violation levels that Staff has proposed for Portland General Electric Company (PGE), PacifiCorp noted that Staff has proposed violation levels that are set at exactly twice the number of violations for each violation level when compared to those that were set for PacifiCorp. For example, while violation level one is 75 violations for PacifiCorp, Staff proposed to set that level at 150 violations for PGE.[6] While PacifiCorp and PGE are two different utilities with very different service territories, the level of violations for PGE is not so dramatically different from PacifiCorp as to justify twice the number of violations per violation level. Therefore, PacifiCorp proposes that the number of violations corresponding to each violation level be doubled consistent with Staff's proposal for PGE.

Q. What are the modifications that PacifiCorp is proposing to Safety Staff's audit?

A. PacifiCorp is proposing two modifications to Safety Staff's audit. First, the current mechanism's violation levels are based on probable violations, and this is inappropriate. Any violation that is used to prevent recovery of reasonable and prudent vegetation management costs should be verified. Second, audit results from lines that are not trimmed within the cycle covered by the vegetation management

[6] *In the Matter of the Application of Portland General Electric for a General Rate Revision*, Docket No. UE 394, Staff/600, Dloughy/28 (Oct. 25, 2021).

mechanism should not be included as violations. Any audit of the program, as a whole, can only be valid once the utility goes through a full cycle for all rights-of-way. Otherwise, audit results from outside recently worked lines result in a penalty to the utility unless it spends the money to trim every line every year. This is additionally consistent with how Safety Staff limits its audit of overhead facilities to only those facilities that were inspected allowing for the two-year correction time period to have occurred before the audit.

Q. Please explain PacifiCorp's proposal to modify the basis point penalty percentage.

A. PacifiCorp is proposing to modify basis point penalty percentage to a sharing percentage penalty. Instead of imposing an earnings test on recovery, it is more appropriate to create a sharing mechanism, whereby a greater level of violations results in otherwise prudent expenditures partially shifting to shareholders if violations do not meet the criteria.

Q. Please explain PacifiCorp's proposal to allow for full recovery of costs related to inflation and regulatory mandates.

A. Costs related to inflation and new regulatory mandates are entirely outside of PacifiCorp's control. Therefore, it is not appropriate that the Company be denied recovery of these costs. A utility should be encouraged to adopt new programs in response to regulatory requirements as soon as possible. Additionally, the recent increase in costs due to inflation and labor costs, along with general competition across the industry for skilled vegetation management companies, puts a substantial amount of risk on the utility. As a result, PacifiCorp proposes that the recovery of those costs occur on a dollar-for-dollar level outside of the performance-based limitations that are described above. PacifiCorp proposes to calculate the annual inflation based on IHS Markit indices. These costs would then be included in the Company's annual filing as a separate line item for full recovery, subject to review by parties.

Q. How would PacifiCorp's proposal compare to the current WMVM?

A. Table 3, below, compares the current program and the program proposed by PacifiCorp.

Table 3: Comparison of the Current WMVM to PacifiCorp's Proposed Mechanism

CURRENT MECHANISM			
$30m	Base Rates		
$30m - $36.645m	Recovery based on earnings test	**Number of Violations**	**Earnings Test**
		0 - 74	NONE
		75 – 149	- 100 BP
		150 - 199	- 150 BP
		200+	- 200 BP
>$36.645m	Recovery based on earnings test	**Number of Violations**	**Earnings Test**
		0 - 149	NONE
		150+	- 50 BP
Violations	System Audit (includes lines not inspected in current cycle)		
	All Probable Violations		

PROPOSED MECHANISM				
$50m	Base Rates	Increase to transition to a 3-year cycle program and address inflationary cost pressures		
$50m - $58m	Recovery based on sharing bands	**Number of Violations**	**Sharing Bands**	
		0-150	NONE	- Actual Violations - Line inspected in cycle
		151-300	95/5	
		300-500	90/10	
		>500	80/20	
>$58m	Recovery based on sharing bands	**Number of Violations**	**Sharing Bands**	
		0-74	NONE	- Actual Violations - Line inspected in cycle
		>74	50/50	
Violations	Lines in cycle audit (lines inspected within the term of the mechanism)			
	Actual Violations			
Exceptions	Inflation Adjustment			
	Changes in Regulatory Requirements after setting base rates			
Outside of Mechanism	$15.8m (WPP)	Subject to balancing account treatment per SB 762		

VII. CONCLUSION

Q. Please summarize your recommendation to the Commission.

A. My testimony demonstrates that there can be significant costs and impacts to the Company and its customers associated with wildfires. Therefore, it is prudent for PacifiCorp to make incremental investments in wildfire mitigation projects to reduce the risk of wildfires caused by its facilities in its service territories, especially as wildfires have grown in frequency and severity in the West. Additionally, my testimony details the increases in costs for vegetation management, and changes to the WMVM to improve its effectiveness and functionality. I recommend the Commission approve these investments and proposed changes.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 399
Exhibit PAC/701
Witness: Allen Berreth

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Allen Berreth

PacifiCorp Service Territory with FHCA

March 2022

RISK-BASED APPROACH: Fire High Consequence Areas (FHCA)

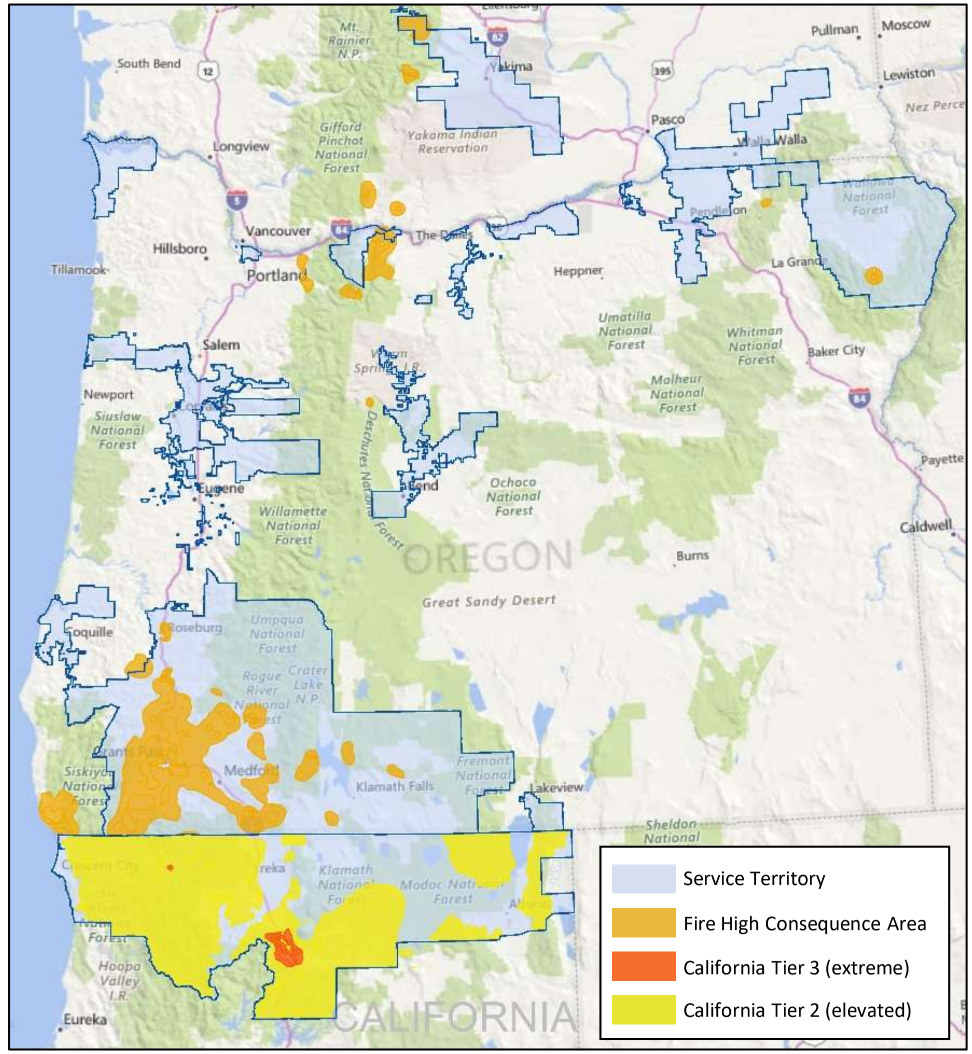
- Utilizing the same modeling concepts used in California, areas were identified in Oregon and Washington where there is an elevated risk of utility-associated wildfires to ***occur*** and ***spread rapidly***, and where communities face an elevated risk of damage or harm from wildfires

- Per state requirement in California, Tier 3 and Tier 2 are shown regardless if facilities exist in the area; making the impact of Tier 2 seem larger than it is

- In Oregon and Washington, a similar methodology was used to identify FHCAs

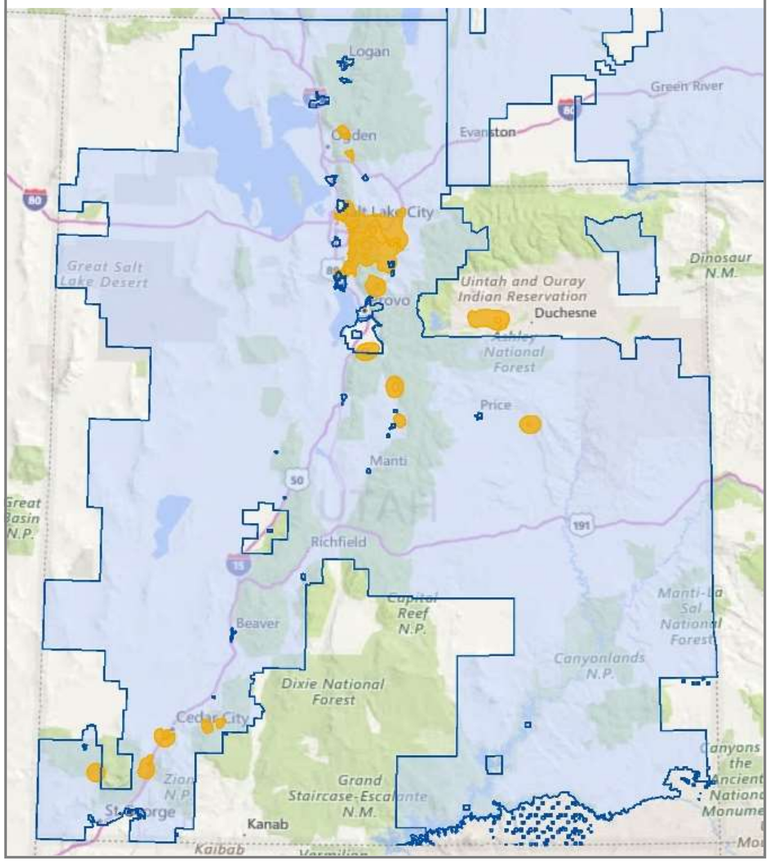
- FHCAs are used to prioritize wildfire mitigation initiatives, such as, increased inspections, system hardening and proactive de-energization

Washington, Oregon, California Service Territory

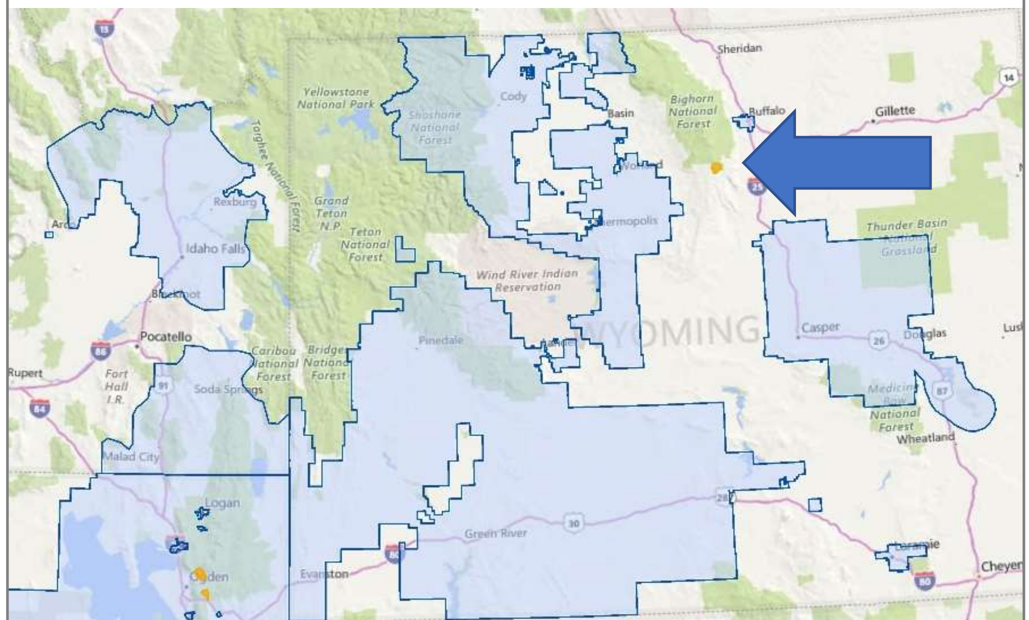


RISK-BASED APPROACH: Fire High Consequence Areas (FHCA)

Utah Service Territory



Wyoming / Idaho Service Territory



Service Territory	
Fire High Consequence Area	

Docket No. UE 399
Exhibit PAC/800
Witness: Erik Anderson

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Erik Anderson

March 2022

TABLE OF CONTENTS

ATTACHED EXHIBITS

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 Erik Anderson, and my business address is 825 NE Multnomah Street, Suite 2000, Portland, Oregon 97232. I am currently employed as the Strategic Manager of Renewable Energy and Emerging Technology with PacifiCorp.

Q. Please describe your education and professional experience.

A. I received a Bachelor of Science degree in Liberal Studies from Portland State University in 2005, and a Juris Doctorate degree from the Northwestern School of Law at Lewis and Clark College in 2010. My current position focuses on policies and programs that facilitate the development of customer sited energy resources as well as the development of voluntary renewable programs. Prior to my current position I was the Customer Generation Manager at PacifiCorp.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your direct testimony?

A. The purpose of my testimony is to describe PacifiCorp's proposed voluntary renewable energy tariff (VRET) for nonresidential customers, which is proposed in Schedule 273, Accelerated Commitment Tariff (ACT). I have included proposed Schedule 273 as Exhibit PAC/801. I also explain how the program satisfies the design conditions approved in Public Utility Commission of Oregon (Commission) Order 16-251[1] and subsequently modified by Order 21-091.[2]

Q. Please summarize your recommendation in this proceeding.

A. I recommend that the Commission approve PacifiCorp's proposed Schedule 273.

Q. Is approval of specific customer agreements part of the Company's proposal in this proceeding?

A. No. Currently, PacifiCorp is not seeking approval of a specific customer agreement, resource selection or credit value. Instead, PacifiCorp will seek approval of those items through compliance filings as customer specific agreements are finalized.

III. OVERVIEW OF THE ACT

Q. Please summarize PacifiCorp's ACT.

A. As explained by Ms. Joelle R. Steward, the ACT program will provide customers the opportunity to accelerate the decarbonization of their energy supply by facilitating the development of new renewable energy facilities. Through specified renewable resources that are incremental additions to those selected for system use, PacifiCorp will provide bundled renewable energy and the corresponding renewable energy certificates (RECs) sufficient to meet the customers' goals. PacifiCorp will leverage existing competitive procurement processes to identify potential projects eligible for ACT. This will allow the Company to identify a variety of resources that meet

[1] *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).
[2] *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.

customer expectations while minimizing costs and maximizing overall system benefits.

Q. Is the proposed ACT designed to avoid cost-shifting between participants and non-participants?

A. Yes. The ACT has a few key components which are designed to avoid cost shifting from participants to non-participants.

First, ACT participants will remain on their current rate schedule and any applicable riders or supplemental schedules. The cost of participation in the program will be captured through a supplemental rider that reflects all costs for the program. By remaining on the applicable cost-of-service rates, the participant will continue to contribute to recovery of all system costs.

Second, the ACT participant will pay for all administrative costs of the program and the cost of the selected renewable resources. Administrative costs for operating the program will be tracked and charged to the program. The ACT participant will also be responsible for the costs of the bundled renewable energy minus a credit that reflects the system value of the energy and the capacity from the incremental facility.

As explained further below, PacifiCorp will use its integrated resource plan (IRP) portfolio-based valuation method to determine the value of the incremental renewable resource to the system. This value would then be provided to the participant as a credit against the cost for the renewable resource under the contract between PacifiCorp and the participating customer.

Q. How does PacifiCorp's ACT differ from its Blue Sky Program?

A. PacifiCorp's Blue Sky Program merely provides for the sale of RECs to customers for retirement on their behalf, while the ACT program provides bundled energy and RECs to a participating customer. As discussed by Ms. Steward, the ACT program is designed to encourage the incremental addition of renewable resources, increasing the supply of bundled renewable energy to the grid in advance of the state policy goals of House Bill (HB) 2021.

Q. Will PacifiCorp continue its Blue Sky Program?

A. Yes, but only for unbundled RECs that are not associated with incremental generation resources once the Schedule 272 cap is reached.

IV. STRUCTURE OF PACIFICORP'S ACT

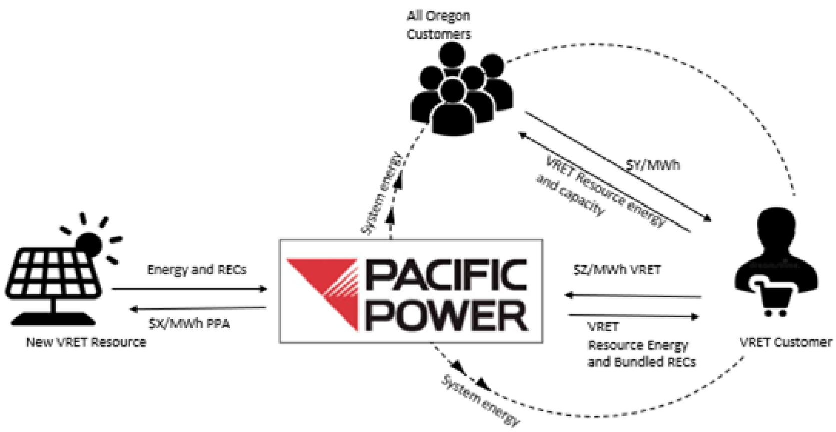
Q. What is the purpose of this section of your direct testimony?

A. In this section of my testimony, I describe the design of the PacifiCorp's proposed ACT.

Q. Please describe the structure of PacifiCorp's proposed ACT.

A. Under a contract entered into between PacifiCorp and a nonresidential customer (participant), PacifiCorp will provide a participant bundled renewable electricity from one or more renewable energy resources acquired by PacifiCorp. The contract with the participant will include rates calculated to cover all costs associated with acquiring the renewable energy resource(s) and operating the program offered under ACT. To reflect the resource energy and capacity that will benefit all Oregon customers, the participant will receive a credit for the contracted megawatt-hours (MWh). The structure of ACT is depicted in Figure 1 below.

Figure 1: ACT Structure



Q. What type of renewable energy resources will be eligible under the ACT?

A. There are four criteria for a renewable energy resource to be eligible under the ACT. First, a renewable resource must derive its energy from a renewable energy source as defined under Oregon Revised Statute (ORS) §469.025. A non-carbon emitting energy storage resource may be included only in conjunction with Resource Portfolio Standard (RPS)-compliant facilities. Second, consistent with ORS §469A.135, a renewable resource must be located where it can provide bundled renewable energy to the Company.[3] Third, the renewable resource must be a new resource in that it must have not been operational earlier than one year prior to the resource being included in the ACT program. Finally, a renewable resource eligible under the ACT program must not already be included in the Company's rates.

[3] It must be located in the United States, within the geographic boundary of the Western Electricity Coordinating Council, and delivered to PacifiCorp's system.

Q. Please explain which nonresidential customers are eligible to participate in the ACT program.

A. Nonresidential consumers served by the Company in the state of Oregon whose total aggregated electric load is at least 30 kW, based on annual peak load, may participate in the ACT program. A customer may satisfy the 30 kW threshold by aggregating multiple metered delivery points, including individual delivery points with less than 30 kW of demand, under a single entity, based on annual peak load at each delivery point. Annual peak load will be based on the customer's highest demand reading during the prior 12-month period or its reasonably projected demand including planned load expansions in the subsequent 12-month period. For new customers wanting to subscribe to the ACT program, annual peak load will be based on the new customer's contract, to be reached within a ramp-up period of 36 months.

Q. Why has PacifiCorp set a 30 kW threshold?

A. The 30 kW threshold was selected in order to provide larger nonresidential customers a path to procure renewable energy. HB 2021 clarified that retail electricity consumers "whose electricity demand at any point of delivery is less than 30 kilowatts" should be provided a portfolio of rate options and expanded that portfolio to include a Community Green Tariff. Customers larger than 30 kW were excluded from participation in that expanded portfolio. By setting the participation threshold at 30 kW, the Company will provide a similar opportunity for larger nonresidential customers to meet their renewable energy goals.

Q. To participate in the ACT program, does a nonresidential customer have to take service under another PacifiCorp retail rate schedule?

A. Yes. To participate, the nonresidential customer must continue to take service under, and pay all components of, its applicable retail rate schedule and all supplemental schedules and riders as determined for each delivery point. As such, customers that subscribe under PacifiCorp's Direct Access Delivery Service are not eligible to participate in the ACT program.

Q. Why are those who take service under direct access schedules ineligible to participate under the ACT?

A. ACT is a program that provides customers access to bundled renewable energy. It is a supplemental product that is an addition to the participant's cost-of-service rates. Participants continue to pay their share of system costs through their standard rates, reducing the risk of stranded assets. Prohibiting Direct Access customers reduces the complexity related to energy delivery, billing, establishing the credit value, and concerns about stranded assets.

Q. What is the length of the contract entered into between PacifiCorp and a participant under the ACT?

A. The contract will include a minimum term of five years as agreed to between PacifiCorp and the participant. If PacifiCorp identifies a resource through a purchase power agreement (PPA) as the best option and the term of the participant contract does not match the term of PPA(s) entered into by PacifiCorp or the asset life of the facility, the participant contract will recover all the costs identified using the IRP portfolio-based methodology described below to protect non-participating customers from the mismatch between participant contract and resource supply. I will refer to this cost as the "subscriber mismatch fee" in my testimony.

Q. Please explain the components of the participants' contract rate under the ACT.

A. The rate that a participant will pay under a contract will reflect the following costs and credit:

1. The participant's normal tariff rate as specified in its applicable electric service Schedule for each delivery point;
2. The cost of the MWh of bundled renewable energy generated and delivered to the participant;
3. Cost-based administrative fees that account for program costs, billing, integration, shaping, firming and other relevant program services; and
4. Costs will be offset with a credit for the contracted MWh that reflects the energy and capacity value. The credit will be determined by the Company by using the Company's IRP portfolio-based methodology. It will also include a risk adjustment and will be determined at the time of resource procurement and be fixed over the contract period.

The credit described above is designed to reflect the benefit that all cost-of-service customers receive from the additional energy and capacity provided by the renewable resources. In the end, this leaves the participant paying the delta between the resource cost and the incremental value of the additional renewable resource.

Q. How do you categorize the costs that would be paid by the participant under the ACT?

A. There are three buckets of different costs that will be paid for by the participant in the

ACT program, which is depicted in Figure 2 below.

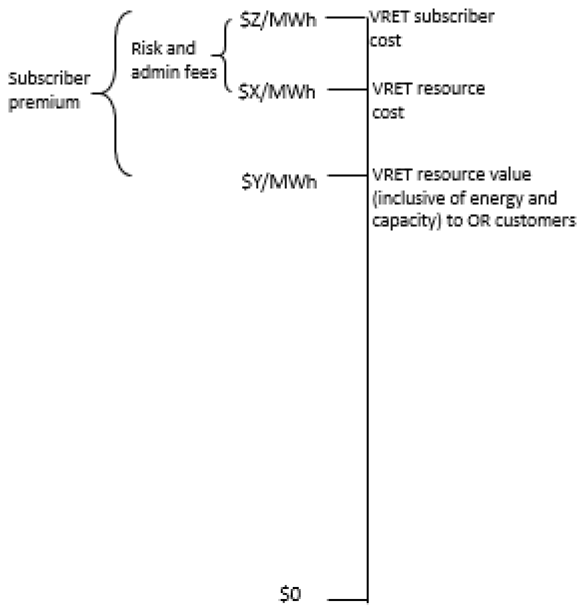
The first cost bucket is the above-market cost from the renewable resource for the bundled renewable energy. As described above, this is the delta between resource cost and the value to the system of the resource's energy and capacity, as determined by the IRP portfolio-based valuation methodology.

The second cost bucket is the subscriber mismatch fee, which is a risk premium charged to participants whose contract length differs from the length of a PPA. In short, the subscriber mismatch fee equals the net present value of the delta between the subscription duration and the PPA duration. Through this fee, PacifiCorp will protect non-participating customers from the impact of unsubscribed energy.

The third cost bucket is the administration fee affiliated with managing the program. All utility costs to manage the program will be tracked and charged only to participants of the program.

I provide additional details on these charges later in my testimony.

Figure 2: Cost Categories to be paid by Participants under the ACT



Q. Who will benefit from the environmental attributes associated with participation in the PacifiCorp ACT?

A. The primary beneficiary of the environmental attributes associated with participation in the ACT program as represented by the RECs will flow to the individual participants of the program. Consistent with the Commission's condition 2 for the design of VRET programs, which I discuss further below, RECs affiliated with this program will either be retired by the utility on behalf of the participating customer or transferred to the customer's Western Renewable Energy Generation Information System account to be retired by the customer directly.

In addition, all customers will benefit indirectly as new "additional" renewable energy facilities will be interconnected into the grid lowering the actual carbon intensity of the energy supply in furtherance of the carbon reduction targets included in HB 2021. See Ms. Steward's testimony for further discussion.

Q. Will the contract entered into between PacifiCorp and the subscribing customer include termination provisions?

A. Yes. The termination provisions will include obligations of the customer to pay all of the costs of the renewable energy resource(s) procured by PacifiCorp on the customer's behalf in the event of early termination. In short, the customer will pay all costs they would have paid under the duration of the contract.

Q. Will a subscribing customer have the option to transfer a contract of one delivery point to another without incurring termination fees?

A. Yes. At the discretion of the Company, a customer with multiple delivery points shall have the option to transfer the renewable energy contract obligation of one delivery point to a new or existing delivery point within the Company's Oregon service territory without termination fees.

V. ENERGY AND CAPACITY CREDITS

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

A. In this section of my testimony, I discuss the energy and capacity credits that will be part of the contract rate for nonresidential customers participating in the ACT program.

Q. You stated that a participating customer's contract rate will include a credit from non-participating customers based on the energy and capacity additions made to PacifiCorp's system. Please provide additional detail regarding that proposed mechanism.

A. The credit represents the system benefit of the additional resource being brought to the system. The credit is inclusive of energy and capacity value of the specific resource using the same methodology used to develop PacifiCorp's IRP and in long-term resource evaluation conducted during a request for proposals for resources. The IRP portfolio-based resource valuation methodology compares the system costs of different portfolios of resources that could be used to serve customers, and accounts for all of the costs associated with utility-scale resources, along with the specific benefits a portfolio of resources provides. As a benefit being brought to the system by the customer, the credit is used to offset the contracted cost of the resource.

The Company's IRP portfolio-based modeling does not pre-suppose the values for these benefits applicable to a particular resource.

Q. How is the energy and capacity credit calculated?

A. The energy and capacity credit is calculated by determining the system benefit of the additional resource. The system benefit is based on two simulations in the IRP model, one for a portfolio that includes the incremental generation from the project and one for a portfolio that does not include the incremental generation from the project. As a result, the credit will reflect the difference in total system cost for a portfolio with the additional resource, relative to the least-cost, least-risk portfolio that does not include that resource. The system value of the incremental energy is converted to a dollar-per MWh value by dividing the reduction in annual system costs by the participant's subscribed volume.

Q. Would the energy and capacity credit change during a customer's course of participation?

A. No. The credit and volume are fixed at the time of PPA signing or resource investment decision for PacifiCorp-owned resources. This supports transparency for participants regarding costs of participation.

Q. Is PacifiCorp requesting that the Commission approve the values associated with the credits at this time?

A. No. PacifiCorp is only requesting approval of the tariff structure. Included in that tariff structure are the methods through which PacifiCorp will determine the customer pricing and the credit value the customer receives. The specific values will be brought to the Commission as a compliance filing upon execution of a customer agreement. At that time, PacifiCorp will seek approval of the specific values.

VI. SUBSCRIBER MISMATCH FEE AND ADMINISTATION FEE

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

A. In this section of my testimony, I discuss the subscriber mismatch fee and administrative fee for which participants will be responsible under the contract entered into under the ACT.

Q. What is the subscriber mismatch fee?

A. As I described above, for participants that subscribe to the program in terms that are not equivalent to the length of a PPA, the net present value of the above market costs for the full duration of the contract are spread across the years to which the participants have subscribed. This is the only risk captured in the subscriber mismatch fee.

Q. Why is the subscriber mismatch fee necessary?

A. One of the primary goals of the program is to limit the risk of cost increases for non-participants. Through the subscriber mismatch fee, the risk of unsubscribed energy at the end of a participant contract raising costs for non-participants are reduced. As the subscriber is paying all costs of the additional resource over the term of their contract, there are no remaining above-market costs for cost-of-service customers to bear.

Q. Will the subscriber mismatch fee apply to PacifiCorp-owned resources?

A. Yes, if a Company-owned resource is selected a subscriber mismatch fee would apply. The methodology for calculating the costs and benefits would be fundamentally the same. The primary difference would be the term for which the costs and benefits were evaluated. With a PPA the term would be the duration of the PPA, while for a Company-owned resource the term would be the asset life of the facility.

Q. How will PacifiCorp limit the risk of unsubscribed energy to non-participants in this program?

A. PacifiCorp will limit the risk of unsubscribed energy by working to match participant demand with the size of the contracted resource. PacifiCorp will wait to enter into a PPA or invest in a resource until the resource is adequately subscribed. PacifiCorp will also manage a participation queue for interested customers seeking to participate in the next resource. Should a participant unexpectedly drop out of the program, that capacity will be offered to customers in order of queue position.

Q. Please explain the administration fee.

A. PacifiCorp will assign all costs to administer the program to the participants in the ACT program. An administrative adder is built into the ACT tariff design to cover program operation costs that are applicable only to participants. This fee is structured as a per-MWh adder to the subscription costs, and initially is based on estimate of costs in similar programs like the Blue Sky programs. These costs are not inclusive of program design and startup costs that are available to all customers (e.g., website and issuance of request for proposal (RFP) but include ongoing costs for operation of the program (including staff oversight time and REC retirement)). Upon approval of the program all costs will be assigned to be collected from program participants.

VII. PLANNING AND COMPLIANCE IMPACTS

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

A. In this section of my testimony, I discuss the impacts of the renewable energy resources contracted for under the ACT on the PacifiCorp's RPS obligations and IRP planning.

Q. Will the ACT resources contribute toward PacifiCorp's RPS obligations?

A. No, the renewable attributes of ACT affiliated facilities, as represented by the RECs from the facility, will not be used to satisfy PacifiCorp's RPS compliance requirements. As described above, RECs will be retired on behalf of the participant or transferred to the participant for retirement.

Q. How will PacifiCorp incorporate the ACT resources in its IRPs?

A. ACT resources will be incorporated into the IRP when the contracts are executed.

Q. How will PacifiCorp address the ACT resource generation in its calculation of net power costs?

A. Resource costs and benefits, including the participant buy-down, are situs-assigned to Oregon consistent with the 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol.[4] Other states will see the ACT resource reflected in their net power costs as a market purchase.

VIII. CUSTOMER INTEREST

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

A. In this section of my testimony, I will explain the process that PacifiCorp will undertake to determine customer interest in participating in the ACT program.

Q. How will PacifiCorp determine customer interest for participation?

A. Since 2016 when HB 4126 raised the possibility of utility offered voluntary renewable energy programs, PacifiCorp has held informal discussions with customers that have expressed interest in a utility program. To this point PacifiCorp has not asked for a formal declaration of interest from any customers and the Company has simply gauged interest and relative size of the associated loads. As the approval process for the ACT begins to take shape, PacifiCorp will ask interested customers to submit a non-binding "Expression of Interest" commitment form. This "Expression of Interest" will allow the Company to develop an estimate of resource size needed to satisfy the existing customer interest in the program.

[4] *In the matter of PacifiCorp, dba Pacific Power, Request to Initiate an Investigation of Multi-Jurisdictional Issues and Approve an Inter-Jurisdictional Cost Allocation Protocol*, Docket No. UM 1050, Order No. 20-024 (Jan. 23, 2020).

Q. What levels of participation will be required for PacifiCorp to implement the program?

A. PacifiCorp has not preestablished a floor that must be met to initiate the program. Instead, through the "Expression of Interest" process described above, PacifiCorp will be able to determine the size of a needed resource, or resources, and the associated participant tolerance for additional costs.

IX. RESOURCE SELECTION

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

A. In this section of my testimony, I discuss how PacifiCorp will select resources eligible for the ACT program.

Q. How will PacifiCorp secure resources for the PacifiCorp ACT Program?

A. Initially, PacifiCorp plans to leverage its existing procurement process initiated as a result of the 2021 IRP[5], the 2022 All-Source RFP (2022AS RFP).[6] The IRP action plan and the subsequent RFPs will identify least-cost, least-risk resources for the system prioritizing selection for all cost-of-service customers. Next, PacifiCorp will identify additional least-cost resources for compliance with other state policy obligations on behalf of the state's retail customers, including Oregon's Renewable Portfolio Standard and HB 2021. Projects that are not selected for system or state-specific needs will be considered as potential projects for the ACT program.

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[5] *In the Matter of PacifiCorp, dba Pacific Power, 2021 Integrated Resource Plan,* Docket No. LC 77. *See also,* https://www.pacificorp.com/energy/integrated-resource-plan.html.
[6] *In the Matter of PacifiCorp, dba Pacific Power, Application for Approval of 2022 All-Source Request for Proposals,* Docket No. UM 2193.

Q. Will PacifiCorp ACT participants get preference over PacifiCorp resource procurement for its system load?

A. No, first preference for resources identified in the 2022AS RFP will go to satisfy system resource needs identified through the 2021 IRP along with state policy obligations on behalf of all retail customers, as described above. Only bids that are not otherwise cost-effective for system or state obligations will be available to satisfy the demand of the ACT program.

Q. Is PacifiCorp planning to own any of the ACT resources?

A. PacifiCorp will consider both PPAs and company-owned assets as eligible renewable resources for the ACT program. For the initial implementation, as I discussed earlier, PacifiCorp will leverage its ongoing 2022AS RFP, where the energy can be secured through a PPA, unless a more economic owned-resource opportunity were to develop. As such, the Company is not proposing any specific accounting safeguards to track return on investment at this time. With regard to other expenses, after the tariff is approved, all costs for marketing, offering and operation of the act program will be separately accounted for and allocated directly to participants through the administration fee. Prior to investing in any owned resources for the ACT program, PacifiCorp will bring a proposal of specific safeguards before the commission for consideration.

X. COMPLIANCE WITH THE COMMISSION'S VRET CONDITIONS

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

A. In Order 16-251, the Commission established nine conditions that a VRET design must meet. The Commission subsequently modified the VRET design criteria to eight conditions in its review of Portland General Electric's VRET in Order 21-091.[7] In this section of my testimony, I explain how PacifiCorp's ACT meets these conditions.

Q. Please list the eight VRET conditions identified by the Commission.

A. The eight conditions are as follows:

Condition 1. RPS definitions that must apply to voluntary renewable energy products are for resource type, location, and bundled RECs. Non-carbon emitting energy storage resources may be included but only in conjunction with RPS-compliant resources.

Condition 2. Voluntary renewable energy options include only bundled REC products. Any RECs associated with serving participants must be retired by or on behalf of participants.

Condition 3. The year that a VRET-eligible resource becomes operational shall be no earlier than one year prior to the resource being included in the program.

Condition 4. The VRET program size is limited to 300 average megawatts (aMW) for PGE and 175 aMW for PacifiCorp.

Condition 5/6. VRET offerings, as customer choice products, can impact the competitive retail market for some customer segments even when differentiated from direct access offerings. The utility bears the burden of proof to demonstrate that a VRET offering does not unfairly undermine Direct Access Programs.

[7] In Order No. 21-091, the Commission consolidates the original Condition 5 and Condition 6 into one Condition 5/6.

Condition 7. The regulated utility may own a voluntary renewable energy resource, but may not include any voluntary renewable energy resource in its general rate base. It may recover a return on and return of its investment in the voluntary renewable energy resource from the subscriber; however, the utility must share some of the return on investment with the other utility customers for ratepayer-funded assets used to assist the voluntary renewable offering.

Condition 8. All direct and indirect costs and risks are borne by the participating voluntary renewable energy tariff customers, shareholders of the utility or third-party developers and suppliers with provisions allowing independent review and verification by Commission Staff of all utility costs. Costs include but are not limited to ancillary services and stranded costs of the existing and additional future cost-of-service rate-based system.

Condition 9. All voluntary renewable offerings must be made publicly available and subject to review by the Commission to ensure they are fair, just, and reasonable.

Q. Has PacifiCorp designed the ACT to meet the requirements included within the eight conditions?

A. Yes.

Q. Please explain how the PacifiCorp ACT meets Condition 1.

A. PacifiCorp has not selected the resources that will be used for the program at this time. Resources that are selected will conform with the definitions for resource type,[8] location,[9] and bundled RECs[10] currently included in Oregon Law.

Q. Please explain how the PacifiCorp ACT meets Condition 2.

A. PacifiCorp's program is designed to encourage the development of new renewable resources and provide a bundled renewable energy certificate to the customer. The contracts affiliated with this program will cover the energy, capacity and renewable attributes of the facilities. PacifiCorp will ensure that the RECs associated with this program are retired on behalf of the participant.

Q. Please explain how the PacifiCorp ACT meets Condition 3.

A. PacifiCorp will only select new incremental renewable resources. Thus, no projects that are operational for more than one year prior to inclusion in the program will be selected as designated resources.

Q. Please explain how the PacifiCorp ACT meets Condition 4.

A. PacifiCorp believes that 175 aMW is sufficient to meet the demand from existing customers for a voluntary renewable energy program. Should demand from existing customers exceed 175 aMW the Company will prospectively seek approval from the Commission to expand the program, in a manner that is procedurally consistent with guidance provided by the Commission in Order 21-091.[11]

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[8] ORS 469A.025.
[9] ORS 469A.135.
[10] ORS 469A.005.
[11] Order No. 21-091 at 16.

Q. Please explain how the PacifiCorp ACT meets Condition 5/6.

A. As designed, the ACT program is a premium offering where participants remain on cost-of-service rates and agree to pay a premium to participate in this program. While the premium alone does not prove that this program will not undermine Direct Access programs, there are additional program features that are not placed on Direct Access providers that will impact participant interest. First, the constraints included within Condition 1 and Condition 3 on the resource type, location and vintage of projects will limit the options for customers interested in the ACT program. Second, the available contract terms, a minimum of five years, in combination with the subscription mismatch fee, ensure that participants are paying all costs for the additional resources for the full duration of the contract. This extended financial commitment is not required from Direct Access customers. Third, the program feature that requires customers to remain on cost-of-service rates and exposed to future rate changes eliminates the ability to use this program as a hedge for their electricity supply costs. In total the premium nature of the ACT program combined with the restrictive procurement, commitment length and lack of any hedge value suggest that the ACT program will not undermine the Direct Access programs.

Q. Please explain how the PacifiCorp ACT meets Condition 7.

A. PacifiCorp will consider both PPAs and company-owned assets as eligible renewable resources for the ACT program. In the initial implementation, PacifiCorp will leverage its ongoing 2022AS RFP, where the energy can be secured through a PPA, unless a more economic owned-resource opportunity were available. The Company will not seek to recover a return on investment for PPA projects. Prior to considering

Company-owned resources for participation in the ACT program, PacifiCorp will identify the specific accounting for the resource in a filing with the Commission, including either a mechanism to share any return on investment associated with owned resources in the ACT program with other customers or why the accounting protections are sufficient so that other customers are not harmed and sharing would not be appropriate. PacifiCorp will not include any Company-owned renewable resources affiliated with the ACT program in its general rate base. Costs will instead be recovered from participants in the ACT program.

Q. Please explain how the PacifiCorp ACT meets Condition 8.

A. The ACT program assigns all ancillary program costs to participating customers, this includes administration and other ancillary services. Additionally, requiring customers to remain on the applicable cost of service rates for delivery points participating in the program means that participating customers continue to pay for their share of all system costs.

Q. Please explain how the PacifiCorp ACT meets Condition 9.

A. All agreements affiliated with this program will be available to Staff for review. Staff will be able to verify all terms, conditions and prices affiliated with these agreements. PacifiCorp will make these agreements available on a confidential basis to protect customer-specific and project-specific information.

XI. CONCLUSION

Q. Please summarize your recommendation to the Commission.

A. I recommend that the Commission approve PacifiCorp's proposed ACT.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 399
Exhibit PAC/801
Witness: Erik Anderson

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Erik Anderson

Proposed Schedule 273 Nonresidential Accelerated Commitment Tariff

March 2022

PACIFIC POWER
A DIVISION OF PACIFICORP

(N)

Purpose

This Schedule governs contract guidelines for the Company to acquire renewable energy from new renewable resources on behalf of participating Customers. Under this Schedule, a Nonresidential Consumer may commit to the purchase of bundled renewable energy from a new renewable facility, or group of facilities, in a quantity not to exceed the Customer's yearly consumption.

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Nonresidential Consumers served by the Company in the state of Oregon whose total aggregated electric load is at least 30 kW, based on annual peak load. A Customer may aggregate multiple metered delivery points, including individual delivery points with less than 30 kW of demand, under a single entity to satisfy the 30 kW threshold, based on annual peak load at each delivery point. Annual peak load will be based on the Customer's highest demand reading during the prior 12-month period or its reasonably projected demand including planned load expansions in the subsequent 12-month period. For new Customers, annual peak load will be based on the Customer's Contract Demand, to be reached within a ramp-up period of 36 months or such other period approved by the Commission.

Conditions of Service

1) A contract is required for each Customer taking service under this Schedule. The Customer contract is subject to approval by the Commission.

2) While a participant in this Schedule, each Customer shall continue to take service under, and pay all components of, their applicable rate schedule and all supplemental schedules and riders as determined for each delivery point. Customers who subscribe to Direct Access Service, are ineligible for this program.

3) The Customer contract will provide for delivery of bundled renewable electricity to the Customer by the Company from one or more renewable energy resources. See Conditions of Service paragraph 6, below, for eligible renewable energy resources criteria.

(continued)

(N)

Conditions of Service (continued) (N)

4) The Customer contract will include:

   a) The amount of renewable energy to be acquired on behalf of the Customer annually. This amount shall not exceed the reasonably projected annual amount of energy to be consumed by the Customer. In the event of yearly under generation from the renewable energy resource(s) facilitated through the contract, the Company will purchase renewable energy certificates (RECs) on the Customer's behalf to ensure the Customer's subscribed quantity of energy is covered.

   b) The Customer contract will include rates calculated to cover all costs associated with acquiring the renewable energy resource(s) and operating this supplemental program. Under the Customer contract the Customer shall pay:

      i) The Customer's normal tariff rate as specified in the applicable Electric Service Schedule for each delivery point:
      ii) The cost for the contracted megawatt-hours (MWh) of bundled renewable energy generated and delivered to the customer:
      iii) Cost-based administrative fees that account for program costs, billing, and other relevant program expenses:
      iv) The credit for the contracted MWh that reflects the energy and capacity value, as well as integration, shaping, and firming costs. The bill credit amount is determined by the Company, using the Company's integrated resource plan (IRP) portfolio-based valuation methodology. The credit value will include a risk adjustment, will be determined at the time of resource procurement, and will be fixed over the contract period.
      v) The subscriber mismatch charge that ensures that incremental renewable energy resource costs are recovered during the term of the Customer's agreement.

   c) The Customer contract will include a term no less than five years, as agreed to between the Company and the Customer. Should the term of the contract differ from the term of the renewable energy resource(s), the subscriber mismatch charge identified in the contract will recover all of the costs identified using the IRP portfolio-based valuation methodology to protect non-participating cost of service Customers from the mismatch between contract durations.

   d) The Customer contract will contain service termination provisions obligating the Customer to pay all of the costs of the renewable energy resource(s) procured by the Company on the Customer's behalf in the event the Customer contract is terminated early, and a cost obligation related to the renewable energy resource(s) continues beyond the termination. At the discretion of the Company, a Customer with multiple delivery points shall have the option to transfer the renewable energy resource obligation of one delivery point to a new or existing delivery point within the Company's Oregon service territory without termination fees.

   e) The Customer shall be required to provide adequate credit assurances.

(continued)

(N)

PACIFIC POWER
A DIVISION OF PACIFICORP

Conditions of Service (continued) (N)

5) At the request of a Customer, the Company may agree to enter into a new contract with another Customer to accommodate a transfer of the Customer’s rights and obligations with respect to a renewable energy resource to another Customer, subject to Commission approval of the new contract.

6) The following provisions set out the criteria for renewable energy resources eligible under this Schedule:

    a) A renewable resource must derive its energy from a renewable energy source as defined in Oregon Revised Statute 469A.025. Non-carbon emitting energy storage resources may be included, but only in conjunction with Renewable Portfolio Standards-compliant resources.
    b) A renewable resource must be located where it can provide bundled renewable energy to the Company, as such it must be located in the United States and within the geographic boundary of the Western Electricity Coordinating Council consistent with Oregon Revised Statute 469A.135. The Company will take physical delivery of output from the renewable resource and will provide electric service to the Customer.
    c) A renewable resource must be new, meaning that the facility must not have been operational earlier than one year prior to the resource being included in the program.
    d) A renewable resource eligible for contract under this Schedule must not already be included in the Company’s rates.
    e) The renewable resource procurement will be negotiated by the Company and all terms and conditions are subject to the Company’s agreement.

7) RECs associated with renewable energy delivered under this Schedule will be deposited into an account maintained by or on behalf of the Customer and will be retired.

(N)

Docket No. UE 399
Exhibit PAC/900
Witness: Kenneth L. Elder, Jr

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Kenneth Lee Elder, Jr

March 2022

TABLE OF CONTENTS

I. INTRODUCTION AND QUALIFICATIONS

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

A. My name is Kenneth Lee Elder, Jr. My business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My position is Load Forecasting Manager.

Q. Briefly describe your education and professional experience.

A. I have a Bachelor's Degree in Agriculture Business from Tarleton State University and a Master's Degree in Agricultural and Resource Economics from Colorado State University. I have been employed by PacifiCorp since July 2016, where I have managed load forecasting and load research activities. From 2008 through 2016, I was an economist for a natural resource consulting firm. From 2004 through 2008, I was an economist for the University of Alaska Fairbanks.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have previously filed testimony on behalf of the Company in regulatory proceedings in Utah.

II. PURPOSE OF TESTIMONY

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

A. The purpose of my testimony is to explain how the Company developed the forecasts of the number of customers, kilowatt-hour (kWh) sales at the meter (sales), system loads and system peak loads at the system input level (loads), and number of bills by rate schedule for the 12-month period ending December 31, 2023.

III. OVERVIEW

Q. When did the Company prepare the sales and load forecast used in this filing?

A. The sales and load forecast used in this filing was completed in May 2021. The May 2021 sales and load forecast is the most recent forecast of sales and loads prepared by the Company.

Q. How did the Company use the May 2021 sales and load forecast in this filing and in the Company's concurrent 2023 Transition Adjustment Mechanism (2023 TAM) filing?

A. The May 2021 load forecast was used by Ms. Sherona L. Cheung to calculate the inter-jurisdictional allocation factors. The sales forecast by rate schedule was used by Mr. Robert M. Meredith to allocate costs between customer classes and to design rates that correctly reflect the cost of service. The load forecast was also used by the Company to calculate net power costs in the 2023 TAM filing.[1]

Q. Please provide a general overview of the Company's sales and load forecast methodology.

A. The Company's methodology consists of first developing a forecast of monthly sales by customer class and monthly peak load by state. This sales forecast becomes the basis of the load forecast by adding line losses, meaning kWh sales levels are grossed-up to a generation or "input" level. The monthly loads are then spread to each hour based on the peak load forecast and typical hourly load patterns to produce the hourly load forecast.

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[1] *In the matter of PacifiCorp, dba Pacific Power, 2023 Transition Adjustment Mechanism*, Docket No. UE 400 (Mar.~~ch~~ 1, 2022).

Q. Please provide a summary of the forecasted energy sales for 2023.

A. Table 1 provides the forecasted energy sales in megawatt-hours (MWh) for the 12-month period ending December 31, 2023 that is used in this general rate case (2023 GRC or 2023 Rate Case).

Table 1 - Test Period Sales Forecast (MWh)

	2023 GRC (CY 2023)	
	Total Company	**Oregon**
Residential	**17,109,240**	**5,780,833**
Commercial	**20,419,167**	**6,321,549**
Industrial	**18,619,291**	**1,465,509**
Irrigation	**1,475,938**	**333,716**
Lighting	**100,089**	**35,996**
Total	**57,723,723**	**13,937,602**

IV. COMPARISONS TO PRIOR SALES FORECASTS

Q. How does the total-company sales forecast for 2023 compare to the sales forecast used in the last general rate case, docket UE 374 (2021 Rate Case)?[2]

A. As shown in Table 2, total-company 2023 forecast sales are 2.5 percent higher than 2021 forecast sales used in the 2021 Rate Case. The difference in the forecasts is attributable to an increase in residential, commercial, irrigation and lighting load. The growth in the residential class is attributable to strong historical class sales over recent years, while the growth in the commercial class is related to data centers. The industrial class decrease in the forecast is primarily attributable to a decline in commodity prices in 2020.

[2] *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).

Table 2 - Total Company Sales Comparison (MWh)

	Previous GRC CY 2021	Current GRC CY 2023	Percentage Change
Residential	16,314,413	17,109,240	4.9%
Commercial	19,256,803	20,419,167	6.0%
Industrial	19,176,292	18,619,291	-2.9%
Irrigation	1,469,416	1,475,938	0.4%
Lighting	99,688	100,089	0.4%
Total	56,316,612	57,723,723	2.5%

Q. How does the Oregon sales forecast for 2023 compare to the sales forecast for the 2021 Rate Case?

A. As shown in Table 3, the 2023 Oregon sales forecast has increased by approximately 1.6 percent from the 2021 sales forecast used in the 2021 Rate Case. The commercial class increase reflects the continuing expansion of data centers in Oregon. The increase in residential class sales is driven by customer growth offset by a decline in use-per-customer. The decline in the industrial load reflects the continuing decline in industrial sales in the Company's Oregon service territory.

Table 3 - Oregon Sales Comparison (MWh)

	Previous GRC CY 2021	Current GRC CY 2023	Percentage Change
Residential	5,671,134	5,780,833	1.9%
Commercial	5,996,343	6,321,549	5.4%
Industrial	1,682,735	1,465,509	-12.9%
Irrigation	333,381	333,716	0.1%
Lighting	32,935	35,996	9.3%
Total	13,716,528	13,937,602	1.6%

V. FORECAST METHODOLOGY

Q. What aspects of the sales and load forecast methodology do you address?

A. First, I describe the updates to the data and assumptions used to produce the sales and load forecasts. Second, I describe the forecasting approach used to develop customer forecasts for all classes. Third, I describe the forecasting approach for developing monthly sales for the residential, commercial, industrial, irrigation, and lighting customer classes. Fourth, I describe how the hourly load forecast is developed. Fifth, I describe how the forecasts by rate schedule for sales and number of bills are developed.

A. Summary of Changes in Forecast Data and Assumptions

Q. Please summarize major updates used to produce the 2023 forecast as compared to the forecast used in the 2021 Rate Case.

A. The Company updated many of its data inputs when compared to the forecast prepared for the 2021 Rate Case. For each of these updates, the Company used the most recent information available.

1. For Oregon, the residential and commercial classes use a historical data period of January 2000 through February 2021. The historical data period used to develop the industrial monthly sales is from January 2008 through February 2021. The irrigation class uses the historical data period of January 2001 through February 2021, while the lighting class uses the historical data period of April 2006 through February 2021.
2. The Company updated the historical data period used to develop the monthly peak forecasts to include January 2008 through December 2020.
3. The Company updated the economic drivers for each of the Company's jurisdictions using IHS Markit data released in March 2021.
4. The Company updated the forecast of individual industrial and commercial customer usage based on the best information available as of February 2021.
5. The time period used to calculate normal weather was defined as the 20-year

time period of 2001 through 2020.

6. The Company rolled forward the line loss calculation to the five-year period ending December 2020.

7. The data used to develop temperature splines was rolled forward based on available customer class hourly data (October 2015 through September 2020).

8. The Company used the residential use-per-customer model with appliance saturation and efficiency results released in July 2020.

Q. Have there been any updates to the forecast methodology used in this case compared to the forecast prepared for the 2021 Rate Case, and the 2021 TAM (docket UE 375)?[3]

A. Yes. The load forecast for the 2023 Rate Case and the 2023 TAM incorporates the Company's expectations for building electrification. Building electrification projections were based on equipment saturations, consumption information, regulatory conventions, and legislative initiatives in the Company's service territory.

B. Customer Forecast Methodology

Q. How are the forecasts for the number of customers for each class developed?

A. For the residential class, the Company forecasts the number of customers using IHS Markit's forecast of number of households or population as the major driver. For the commercial class, the Company forecasts the number of customers using households or population as the major economic driver. For the industrial, irrigation and street lighting classes, the customer forecasts are relatively static and developed using time series or regression models without any economic drivers.

[3] *In the matter of PacifiCorp, dba Pacific Power, 2021 Transition Adjustment Mechanism*, Docket No. UE 375, Order No.20-392 (Oct. 30, 2020).

C. Monthly Sales Forecast Methodology

Q. What methodology does the Company use to forecast the residential class sales?

A. The Company develops the residential sales forecasts as a product of two separate forecasts: (1) the number of customers—as described above; and (2) sales-per-customer. The Company models sales-per-customer for the residential class through a Statistically Adjusted End-Use (SAE) model, which combines the end-use modeling concepts with traditional regression analysis techniques. Major drivers of the SAE-based residential model are heating and cooling-related variables, equipment shares, saturation levels and efficiency trends, and economic drivers such as household size, income, and energy price.

Q. What methodology does the Company use to forecast the commercial class sales?

A. For the commercial class, the Company forecasts sales using regression analysis techniques with non-manufacturing employment or non-farm employment, as the economic drivers, in addition to weather-related variables. Also, similar to how the Company forecasts its largest industrial customers, data center forecasts are based on input from the Company's regional business managers (RBMs). The treatment of data centers is similar to large industrial customer sales, which is discussed below.

Q. How does the Company forecast sales for the industrial customer class?

A. The majority of industrial customers are modeled using regression analysis with manufacturing employment or an industrial production index as the major economic driver. For a small number of industrial customers, the largest on the Company's system, the Company individually forecasts these customers based on input from the customer and information provided by the RBMs.

Q. What methodology does the Company use for the irrigation and lighting sales forecasts?

A. For the irrigation class, the Company forecasts sales using regression analysis techniques based on historical sales volumes and weather-related variables. Monthly sales for lighting are forecast using regression analysis techniques based on historical sales volumes and a light-emitting diode lighting adoption curve.

D. Hourly Load Forecast

Q. Please outline how the hourly load forecast is developed.

A. After the Company develops the forecasts of monthly energy sales by customer class, a forecast of hourly loads is developed in two steps.

First, monthly peak forecasts are developed for each state. The monthly peak model uses historical peak-producing weather for each state and incorporates the impact of weather on peak loads through several weather variables that drive heating and cooling usage. These weather variables include the average temperature on the peak day and lagged average temperatures from up to two days before the day of the peak. This forecast is based on average monthly historical peak-producing weather for the 20-year period 2001 through 2020.

Second, the Company develops hourly load forecasts for each state using hourly load models that include state-specific hourly load data, daily weather variables, the 20-year average temperatures identified above, a typical annual weather pattern, and day-type variables such as weekends and holidays as inputs to the model. The hourly loads are adjusted to match the monthly peaks from the first step above.

Also, the hourly loads are adjusted so the monthly sum of hourly loads equals monthly sales plus line losses.

Q. How are monthly system coincident peaks derived?

A. After the hourly load forecasts are developed for each state, hourly loads are aggregated to the total system level. The system coincident peaks can then be identified, as well as the contribution of each jurisdiction to those monthly peaks.

E. Forecasts by Rate Schedule

Q. Were any additional forecasts created for these proceedings?

A. Yes. As mentioned earlier, Mr. Meredith requires two additional forecasts that are based on the kWh sales forecast and the number of customers forecast. Once the kWh sales forecast is complete, it must be applied to individual rate schedules to forecast kWh sales by rate schedule. In addition, the forecast of number of customers by rate schedule must be expressed in number of bills.

Q. How are rate schedule level forecasts produced?

A. The Company develops this forecast in two steps. First, the Company forecasts test year sales by rate schedule. Then the Company proportionally adjusts the rate schedule sales forecasts so that the total across the rate schedules matches the customer class forecast.

Q. How does the Company forecast the number of bills for each rate schedule?

A. The forecast of the number of bills for each rate schedule follows the same process as the sales forecast for each rate schedule. First, the Company forecasts the number of bills by class and by rate schedule. Then, the Company proportionally adjusts the forecasted number of bills by rate schedule so that the total number of bills across the rate schedules matches the customer class forecasted number of bills.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 399
Exhibit PAC/1000
Witness: Sherona L. Cheung

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Sherona L. Cheung

March 2022

TABLE OF CONTENTS

ATTACHED EXHIBITS

Confidential Exhibit PAC/1006—Transmission Wheeling - Facebook Support

Confidential Exhibit PAC/1007—Bridger Mine Reclamation Support

Confidential Exhibit PAC/1008— Regulator Assets & Liabilities Adjustment Support

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 Sherona L. Cheung, and my business address is 825 NE Multnomah Street, Suite 2000, Portland, OR 97232. I am currently employed as Revenue Requirement Manager for PacifiCorp.

Q. Briefly describe your educational and professional background.

A. I earned my Bachelor of Commerce with a major in Finance in 2008. In 2011, I obtained my Certified Management Accounting designation in British Columbia, Canada. In addition to my formal education, I have attended several utility accounting, ratemaking, and leadership seminars and courses. I have been employed by the Company since May of 2013 in various positions within the regulation organization. In April 2021, I was promoted to Revenue Requirement Manager.

Q. What are your responsibilities as Revenue Requirement Manager?

A. My primary responsibilities include overseeing the calculation of PacifiCorp's revenue requirement and the preparation of various regulatory filings in Washington, Oregon, and California. I am also responsible for the calculation and reporting of PacifiCorp's regulated earnings and the application of the inter-jurisdictional cost allocation methodologies.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have previously provided testimony in California and Washington.

II. PURPOSE AND SUMMARY OF TESTIMONY

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

A. My direct testimony addresses the calculation of the Company's Oregon-allocated revenue requirement, excluding net power costs (NPC), and the revenue increase requested in the Company's filing. Specifically, I provide testimony on the following:

- The calculation of the $84.4 million revenue increase requested in this general rate case (GRC) representing the increase over current rates required for the Company to recover its Oregon non-NPC revenue requirement of $1,044.8 million. The Company currently recovers its NPC through the Transition Adjustment Mechanism (TAM).
- The selection of the historical period of the 12 months ended June 2021 (Base Period) as the basis for the test period in this proceeding.
- The development of the forecast test year in this case, which is the 12-month period ending December 31, 2023 (Test Period).
- The treatment of forecasted capital additions included in the revenue requirement calculations, which have been limited to projects placed in service before January 1, 2023, the beginning of the Test Period.
- The presentation of the normalized results of operations for the Test Period demonstrating that under current rates the Company will earn an overall return on equity (ROE) in Oregon of 4.7 percent, which is less than half of the Company's currently authorized ROE of 9.5 percent and the 9.8 percent requested by the Company and supported by Ms. Ann E. Bulkley in this proceeding.

Q. How have you organized your testimony?

A. I have divided my testimony into three sections. I discuss the development of the Company's revenue requirement, including the base and test periods, in Section III, Revenue Requirement. In Section IV, Inter-jurisdictional Allocations, I address the allocation methodology used in this filing. In Section V, Oregon Results of Operations, I provide a description of the Oregon Results of Operations, including a review of the information contained in Exhibit PAC/1002.

III. REVENUE REQUIREMENT

Q. What is the revenue requirement to achieve the requested ROE in this case?

A. At current rate levels, the Company will earn an overall ROE in Oregon of 4.7 percent during the Test Period. This return is less than the 9.5 percent ROE authorized in the Company's 2021 general rate case, docket UE 374 (2021 Rate Case).[1] The Company is proposing to change the authorized ROE in this case to 9.8 percent. A 9.8 percent ROE produces a non-NPC revenue requirement of $1,044.8 million based on the 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol (2020 Protocol). Exhibit PAC/1001 provides a summary of the Company's Oregon-allocated results of operations for the Test Period. Exhibit PAC/1002 provides the supporting details and calculations and is discussed in greater detail later in my testimony.

Q. Please explain how you have treated NPC in this filing.

A. As noted above, the Company recovers its NPC through the TAM, which was

[1] *In the matter of PacifiCorp dba Pacific Power Request for a General Rate Revision,* Docket No. UE 374, Order No. 20-473 at 31 (Dec. 18, 2020). The Commission set an overall rate of return at 7.137 percent and an authorized return on equity of 9.5 percent.

concurrently filed with this general rate case[2] on March 1, 2022, for calendar year 2023 NPC. To model the non-NPC revenue requirement for this case, the Company first computed an overall Test Period revenue requirement including the NPC as filed in the TAM and then removed the NPC components from the overall price change. This approach is required to compute certain non-NPC components of the Test Period revenue requirement that are impacted by NPC-related items, such as the embedded cost differential (ECD), and various revenue-sensitive items. Details supporting the overall revenue requirement and the breakout between the TAM and general rate case are provided in Exhibit PAC/1001. Page 1 of Exhibit PAC/1001 also shows the division of revenue requirement between the TAM and general rate case components, and the resulting general-rate-case-related price change requested in this case.

A. Base Period

Q. Why did the Company use July 2020 through June 2021 as the historical basis, or Base Period, for developing the Test Period in this case?

A. The Company selected the 12-month period ended June 2021 as the historical basis for this case because it was the most recent total-company data available for inter-jurisdictional allocations to achieve a filing date of March 1, 2022. The Company audits and extracts total-company accounting information with the data components necessary for state allocations on a semi-annual basis for the 12-month period ending June and December each year. This semi-annual data extract and review procedure is a key control measure to ensure the accuracy and reliability of the data, which serves

[2] *In re the matter of PacifiCorp d/b/a Pacific Power 2023 Transition Adjustment Mechanism,* Docket No. UE 400 Advice No. 22-003 Initial Filing (Mar. 1, 2022).

as the basis for each of the Company's results of operations and general rate case filings.

Q. Why was a March 1, 2022, filing date for this general rate case necessary?

A. In Order 09-274, the Public Utility Commission of Oregon (Commission) adopted a stipulation establishing guidelines for future TAM filings, including the following provision:

> In all future filings after UE 207 in a year in which the Company files a general rate case, the TAM will be included in or processed concurrently with the general rate case filing. *In future filings after UE 207, the Company agrees that both filings will be made no later than March 1 to allow for a January 1 rate effective date*.[3]

PacifiCorp is filing this general rate case and the concurrent TAM on March 1, in adherence to the requirement set forth in Order 09-274.

Q. When will calendar year 2021 total-company data become available on an inter-jurisdictional allocation basis?

A. Only once total-company data is audited does it become available to begin analysis on an inter-jurisdictional allocation basis. Because of the unique complexities the Company faces as a multi-jurisdictional utility, additional time is necessary once total-company financial data is finalized to ensure state-allocated data is accurate. Due to these complex steps, calendar year 2021 data will not be available for use as the basis of a forecast test period until the end of April 2022, almost two months after this general rate case is filed.

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[3] *In the matter of PacifiCorp dba Pacific Power 2009 Transition Adjustment Mechanism*, Docket No. UE 199, Order No. 09-274, Appendix A at 13 (July 16, 2009) (emphasis added).

B. Test Period

Q. What Test Period did the Company use to determine revenue requirement in this case?

A. The forecast Test Period used by the Company in this proceeding is the 12 months ending December 31, 2023.

Q. Why did the Company choose the year ending December 31, 2023, as the Test Period?

A. The Test Period in this case was selected to best reflect the conditions during the time the new rates will be in effect. The requested rate effective date in this case is January 1, 2023, which matches the start of the Test Period used by the Company in the calculation of the revenue requirement. The Test Period in this general rate case also matches the test period used in the development of the NPC filed in the concurrent TAM.

Q. Please explain how the Company developed the revenue requirement for the Test Period.

A. Revenue requirement preparation began with historical accounting information; in this case, the Company used the 12 months ended June 30, 2021. Each of the revenue requirement components in the Base Period was analyzed to determine if a normalizing ratemaking adjustment was warranted to reflect normal operating conditions. The historical information was then adjusted to recognize known, measurable, and anticipated events. Previous Commission-ordered adjustments are also included as part of the Company's revenue requirement calculation for the Test Period.

Q. What is the significance of beginning with historical information?

A. The Company begins with historical accounting information and makes discrete adjustments to arrive at the Test Period revenue requirement. Beginning with historical information provides a solid foundation that is readily available for audit by all who wish to participate in the case. Individual adjustments are also available for review, and regulators and intervenors may determine each adjustment's relevance and accuracy.

Q. Please summarize the process used to adjust the historical accounting information to reflect Test Period revenues and costs.

A. Revenues are adjusted by applying the current Commission-approved tariff rates to the Test Period load projection. NPC are developed using the Aurora model from Energy Exemplar. The results of the Aurora run for the Test Period are embedded in the results for calculation purposes only; as previously mentioned, recovery of these costs is sought through the TAM filing. Historical operations and maintenance (O&M) expenses, excluding NPC, are split into labor and non-labor components. Non-labor costs are adjusted for inflation using inflation indices developed specifically for electric utilities provided by Information Handling Services (IHS Markit, previously Global Insight) and for other distinct changes required to reflect conditions expected during the Test Period. Historical labor costs are also adjusted for contractual and anticipated increases through the end of the Test Period.

Q. Does the Company rely solely on its own projections of future cost increases?

A. No. For example, the adjustment made to account for inflation between the historical period and the Test Period relies on inflation indices published by IHS Markit.

Updates to pension and benefits expenses are made in accordance with forecasts from actuarial reports, while labor expenses governed by union contracts are walked-forward to Test Period levels using contractual labor increase percentages.

Q. How has the Company addressed areas where cost increases are different than inflation?

A. The Company's business units were asked to identify areas where budgets were significantly different than historical amounts, adjusted for wage increases and inflation. When differences were identified, the business units were asked to provide support for changes in the number, or frequency, of activities. An example of this type of adjustment is the Wildfire and Vegetation Management Expenses adjustment (adjustment page 4.11). Adjustments of this nature are necessary because inflation indices account for cost increases on existing units of production, not changes in volume or processes.

Q. Has the calculation of federal income tax expense been changed since the last general rate case?

A. No; federal income tax expense for ratemaking is calculated using the same methodology that the Company uses in preparing its filed income tax returns. As with the previous general rate case, the federal income tax rate is reflected at 21 percent, which represents the current enacted federal income tax rate.

Q. Are changes being proposed to depreciable lives in this case?

A. Yes. This filing includes updated depreciation expense for Colstrip Units 3 and 4, Craig Unit 2, and Hayden Units 1 and 2. For these specific coal-fired generation units, the Company is proposing to revise the end of their depreciable lives to align with each unit's planned retirement dates as outlined in the Company's 2021 Integrated Resource Plan (IRP). For all assets other than the specific units identified above, however, depreciation expense reflected in the Company's revenue requirement calculation is based on approved depreciation rates by the Commission in the Company's 2018 Depreciation Study[4] and in the Company's 2021 Rate Case. Please see the direct testimony of Ms. Joelle R. Steward for discussion on the Company's proposal for these units. I will address how this update is reflected in the derivation of the Test Period revenue requirement later in my testimony.

Q. Is PacifiCorp including the TB Flats Wind Project in this GRC?

A. Yes, while the prudence of PacifiCorp's investment in the TB Flats Wind Project was approved in the 2021 Rate Case,[5] only a portion of the costs were in-service at the time of the rate effective date. The remaining costs are being brought into rates at this time.

Q. What is the impact of TB Flats?

A. The Company has included in rate base an additional $453.1 million total-company, or $118.1 million Oregon-allocated, capital placed in-service since December 31, 2020.

Q. Are there any additional costs that have been included in this case beyond what was approved in the last GRC?

A. Yes. The total project cost in this proceeding is approximately $15.8 million higher overall on a total-company basis when compared to the 2021 rate case. Please refer

[4] *In the Matter of PacifiCorp dba Pacific Power Application for Authority to Implement Revised Depreciation Rates,* Docket No. UM 1968, Application (Sept. 13, 2018).
[5] *In the Matter of PacifiCorp dba Pacific Power, Application for a General Rate Revision*, Docket No. UE 374, Order No. 20-473 at 50 (Dec. 18, 2020).

to the direct testimony of Mr. Timothy J. Hemstreet for further information on the reasons impacting project cost outcomes.

Q. Please explain when the TB Flats Wind Project came online and PacifiCorp's deferral of costs since the online date.

A. As noted above, a portion of the TB Flats Wind Project was placed in-service in December 2020. That portion of the capital costs was included in rates that became effective on January 1, 2021. The remainder of the TB Flats Wind Project was then placed into commercial operation by July 2021. Upon completion of the remainder of the project, the Company filed an application for approval of deferred accounting to allow it to match the costs and benefits of TB Flats, a renewable resource, for later inclusion in rates.[6] This deferral records the costs and benefits of the TB Flats Wind Project that was not placed in-service by December 2020, until these costs and benefits can be fully reflected in customer rates. In this case, the Company is seeking approval to begin amortization of the deferred cost and benefits. Details on the deferral calculation and the Company's proposal to amortize the deferred costs and benefits is further discussed later in my testimony under Section V., F. Tab 8 – Rate Base Adjustments, and supported by my Exhibit PAC/1002 on the corresponding pages outlining calculations and supporting workpapers for adjustment 8.14.

[6] *In the Matter of PacifiCorp dba Pacific Power Application for Approval of Deferred Accounting for Costs Relating to a Renewable Resource Pursuant to ORS 469A.120,* Docket No. UM 2186, Application (Jul. 27, 2021).

Q. How is the Decommissioning Cost Recovery Adjustment and Coal Removal Mechanism docket[7] reflected in the revenue requirement in this case?

A. In July 2021, the Company filed an application under docket UM 2183, requesting an order from the Commission authorizing a new tariff to collect an increase to estimated decommissioning costs of coal-fired generation resources (including remediation and closure costs) reflected in independent estimates conducted by Kiewit Engineering Group, Inc. The application also sought approval of a coal removal mechanism to reduce regulatory lag when coal units are no longer used to serve Oregon customers. Because this on-going docket addresses the recovery of costs associated with coal-fired generation resources decommissioning and removal, these costs are not included as part of revenue requirement in this general rate case.

Q. What components related to wildfire and vegetation management are included in the revenue requirement in this case?

A. Wildfire mitigation capital, wildfire mitigation vegetation management and vegetation management O&M expenses are included in this case as outlined in the direct testimony of Mr. Allen Berreth. Capital projects for wildfire mitigation that have been completed and placed in-service by June 2021 are embedded in the capital balances for the Base Period. Related projects forecasted to be placed in-service after the Base Period are reflected in incremental adjustment 8.4 in my exhibits. Wildfire mitigation capital and O&M expenses included in this case will set the baseline for recovery of wildfire mitigation costs in Oregon rates. In this case, the Company is forecasting wildfire mitigation capital projects to be placed in-service through

[7] *In the Matter of PacifiCorp, dba Pacific Power, Application for Authority to Implement a Decommissioning Cost Recovery Adjustment and Coal Removal Mechanism,* Docket No. UM 2183 (Jul. 8, 2021).

December 2022 of approximately $34.7 million on an Oregon-allocated basis. Wildfire mitigation O&M and vegetation management O&M are updated to forecast levels for the Test Period through adjustment 4.11. Test Period wildfire mitigation O&M is expected to be approximately $19.7 million and non-wildfire vegetation management O&M is expected to be approximately $50.3 million on an Oregon-allocated basis. Page 4.11.1 in my Exhibit PAC/1002 provides a breakdown of these expenses between wildfire mitigation-related vegetation management expenses, non-wildfire vegetation management expenses, and wildfire-related non-vegetation management expenses.

Incremental wildfire mitigation capital and related O&M expenditures beyond what is included in rates set in this rate case will be recovered through a new automatic adjustment clause, as described by Ms. Steward. Non-wildfire vegetation management expenses over and above levels included in rates would be subject to recovery under the proposed mechanism detailed in Mr. Berreth's testimony.

Q. How has the Company treated forecast capital additions to electric plant in service in this filing?

A. The Company has included capital additions to plant in-service through December 31, 2022, rather than through the end of the forecast Test Period and the rate effective period, which would be December 31, 2023. This treatment is consistent with the Company's 2010,[8] 2012,[9] 2013,[10] and 2021[11] Rate Cases.

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[8] *See In the matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 217, Order No. 10-473 (Dec. 14, 2010).
[9] *See In the matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 246, Order No. 12-493 (Dec. 20, 2012).
[10] *See In the matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 263, Order No. 13-474 (Dec. 18, 2013).
[11] *See* Order No. 20-473.

Q. What changes are reflected in this rate case for the Klamath Hydroelectric Facilities?

A. PacifiCorp is a signatory to the Klamath Hydroelectric Settlement Agreement (KHSA), which provides for the transfer of four main-stem Klamath Hydroelectric Project developments, currently licensed to PacifiCorp, to a third-party dam removal entity that will pursue their removal. Consistent with the KHSA, depreciation rates for the Klamath assets were previously approved by the Commission to provide for full depreciation of the Klamath assets by December 31, 2019, in anticipation of the target date for dam removal of 2020 established in the KHSA. The Federal Energy Regulatory Commission (FERC) is currently evaluating the proposal to transfer the license for certain Klamath developments to the Klamath River Renewal Corporation, the dam removal entity under the KHSA. The timing of when FERC will transfer the license, and when PacifiCorp's operations would ultimately cease, remains uncertain. As the current project licensee, PacifiCorp's obligations under the license and FERC regulations continue to require capital investments to support ongoing project operations, ensure compliance with dam safety and other regulatory requirements, and to make other capital expenditures necessary to fulfill obligations under the KHSA to mitigate impacts of ongoing project operations.

Because the timing of license transfer and the cessation of generation from the Klamath assets remains uncertain, PacifiCorp has continued to apply a depreciation rate of 20 percent per year for ongoing capital additions to the Klamath assets, consistent with the depreciation assumption in approved rates that resulted from Company's 2021 Rate Case.

IV. INTER-JURISDICTIONAL ALLOCATIONS

Q. What methodology did the Company use to calculate the Oregon-allocated revenue requirement in this case?

A. The Company's Oregon-allocated revenue requirement is calculated using the 2020 Protocol, which was approved by the Commission in docket UM 1050 on January 23, 2020.[12] This is the same allocation methodology used in the Company's 2021 Rate Case.

V. OREGON RESULTS OF OPERATIONS

Q. Please describe Exhibit PAC/1002.

A. Exhibit PAC/1002, which was prepared under my direction, is the Company's Oregon results of operations report (Report). As previously explained, the Base Period for the Report is the 12 months ended June 30, 2021, which has been normalized and used to calculate the revenue requirement for the Test Period, the 12 months ending December 31, 2023. The Report provides totals for revenue, expenses, depreciation, NPC, taxes, rate base, and loads in the Test Period. The Report presents operating results for the Test Period in terms of both return on rate base and ROE.

Q. Please describe how Exhibit PAC/1002 is organized.

A. The Report is organized into sections marked with tabs as follows:

- Tab 1 Summary contains a summary of Oregon-allocated results according to the 2020 Protocol. Page 1.1 breaks out the non-NPC results and calculates the revenue increase the Company is requesting as part of this general rate case (column 5). Page 1.2 contains a summary of the general rate case request.

[12] *See In the Matter of PacifiCorp d/b/a Pacific Power, Petition for Approval of the 2020 Inter-Jurisdictional Allocation Protocol, Docket No. UM 1050*, Order No. 20-024 (Jan. 23, 2020).

- Tab 2 Results of Operations details the Company's overall revenue requirement, showing unadjusted costs for the Base Period and fully normalized results of operations for the Test Period by FERC account and 2020 Protocol allocation factor.
- Tabs 3 through 8 provide supporting documentation for the normalizing adjustments required to reflect on-going costs of the Company.
- Tab 9 provides the derivation of the ECD included in this case.
- Tab 10 contains the calculation of the 2020 Protocol allocation factors. Factors in this case are based on the load forecast through December 2023 and pro forma account balances.
- Tabs B1 through B20 contain the historical data for the Base Period and are organized by major FERC function.

A. Tab 3 – Revenue Adjustments

Q. Please describe the information contained within Tab 3 Revenue Adjustments.

A. Tab 3 begins with the Revenue Adjustment Index which contains a brief overview of the assumptions used to project Test Period revenues and a list of each normalization adjustment included in this section of the exhibit. The numerical summary (page 3.0.2) identifies each adjustment made to actual revenues and each adjustment's impact on the case. Each column has a numerical reference to a corresponding page in the Report, which contains a lead sheet showing the affected FERC account(s), allocation factor(s), dollar amount, and a description of the adjustment.

Q. Please describe each adjustment made to revenue in Tab 3.

A. **Pro Forma Revenue (page 3.1) –** This adjustment normalizes general business revenues by adjusting to the pro forma revenue level for the Test Period based on forecasted loads. Page 3.1.4 shows a breakout of the TAM and general rate case revenues.

Renewable Energy Certificate (REC) Revenues (page 3.2) – This adjustment removes all REC revenue and REC deferrals booked during the 12 months ended June 2021. Most of Oregon's share of RECs is banked for compliance; however, not all RECs meet the Oregon Renewable Portfolio Standard (RPS) qualifications. Oregon's revenue from RPS ineligible RECs that are sold are passed back to customers through the Oregon property sales balancing account per Commission Order 10-210 in docket UP 260.[13] REC revenues received through Schedule 272 are accounted for in adjustment 8.6 and addressed separately in later sections of my testimony under Section V., F. Tab 8 – Rate Base Adjustments.

Wheeling Revenue (page 3.3) – This adjustment reflects the level of wheeling revenue for the Test Period by adjusting the actual revenue for normalizing, annualizing, and pro forma changes.

Ancillary Revenue (page 3.4) – This pro forma adjustment reflects ancillary revenue changes that are consistent with the forecast NPC treatment reflected in adjustment 5.1 discussed below. The ancillary revenue booked in the 12 months ended June 2021 is adjusted to reflect the Test Period revenue expected per the terms of contracts in effect during the Test Period. The corresponding impact on NPC is included in adjustment 5.1 and in the TAM.

[13] *In the matter of PacifiCorp, dba Pacific Power Application Approval of Sale of Renewable Energy Credits*, Docket No. UP 260, Order No. 10-210 (June 9, 2010).

Fly Ash Revenue (page 3.5) – In October 2020, the Company executed a new contract for sale of fly ash from the Jim Bridger plant. This adjustment annualizes the increase in fly ash sales revenues in the Base Period to reflect Test Period levels consistent with new contract terms. Plants with ash sales revenues in the Base Period are Jim Bridger, Naughton, Craig, and Cholla.

B. Tab 4 – O&M Adjustments

Q. Please describe the information contained behind Tab 4 O&M Adjustments.

A. Tab 4 includes an O&M Expense Adjustment Index followed by a numerical summary and the specific adjustments. The O&M Expense Adjustment Index begins on page 4.0.1 with a brief overview of assumptions used to adjust operation, maintenance, administrative, and general expenses. The numerical summary (pages 4.0.2 to 4.0.3) identifies each adjustment made to actual expenses and that adjustment's impact on the case. Each column has a numerical reference to a corresponding page in the Report, which contains a lead sheet showing the affected FERC account(s), allocation factor(s), dollar amount and a brief description of the adjustment.

Q. Please describe the adjustments made to O&M expense in Tab 4.

A. **Miscellaneous General Expense and Revenue (page 4.1)** – This adjustment removes certain miscellaneous expenses that should have been charged below the line to non-regulated expenses and recognizes revenues from the Oregon Direct Access Opt Out amortization.[14] It also reallocates certain gains and losses on property sales and regulatory expenses to reflect the appropriate allocation.

[14] *In the matter of PacifiCorp, dba Pacific Power, Transition Adjustment, Five-Year Cost of Service Opt-Out*, Docket No. UE 267, Order No. 15-060 at 6 (Feb. 24, 2015).

Wage and Employee Benefits (page 4.2) – Labor-related costs for the Test Period are computed by adjusting salaries, incentives, health benefits, and costs associated with pension, post-retirement benefits, and post-employment benefits for changes expected beyond the actual costs experienced in the period ended June 2021. Collective bargaining agreements are used to escalate union wages where increases are specified,[15] while increases for non-union and exempt employees were based on actual or anticipated increases. Increases are applied to the wages for each employee group according to specified or anticipated timelines to arrive at the test year wages and salaries. The specificity of the Company's wage escalation is important as PacifiCorp has nine collective bargaining agreements across six unions of various sizes. Incentive compensation for non-union employees is included based on the Company's forecast of test year expense, adjusted to remove 100 percent of Named Executive Officers' (NEO) share, and 50 percent of non-NEO incentives. Pension-related service expense and other employee benefit costs are adjusted to the planned expense levels for the Test Period, based on actuarial reports, where available, or by escalating actual costs. Pension-related non-service expenses are reflected in adjustment 4.3, described in the following subsection. Please see the direct testimony of Ms. Nikki L. Kobliha for further discussion of the Company's pension expense in this case.

Page 4.2.1 of the Report provides further description of the procedures used to compute Test Period labor costs. Page 4.2.2 contains a numerical summary of actual

[15] Where union contracts have not yet been finalized for increases that would become effective within the Test Period, an estimated escalation percentage is applied. Actual increases for these unions will be updated as more information becomes available during the pendency of this case.

labor costs in the year ended June 2021 and summarizes the adjustments made to project costs through the Test Period. This summary is followed by detailed worksheets on pages 4.2.3 through 4.2.11.

Pension-Related Non-Service Expense (page 4.3) – This adjustment reflects in the Test Period pension and post-retirement related non-service expenses at anticipated 2023 levels. These expenses have historically been included in the Company's results of operations reports in the Wage and Employee Benefits adjustments (WEBA). However, because these expenses are no longer eligible for capitalization under generally accepted accounting principles and are therefore 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. As discussed in the testimony of Ms. Kobliha, settlement losses are being amortized over the approximately 20-year average remaining life expectancy of plan participants.

Remove Non-Recurring Entries (page 4.4) – This adjustment removes an accounting entry made to an expense account during the Base Period that is non-recurring in nature. Accordingly, the transaction amount is removed to normalize Test Period results. Details on the specific item in the adjustment can be found on Page 4.4.1.

Insurance Expense (page 4.5) – In the 2010 Rate Case, the Commission authorized the Company to establish monthly accruals and associated reserve balances for self-insurance for transmission and distribution property losses, non-transmission and distribution (Non-T&D) property losses, and third-party liability losses.[16] The Commission ordered the accrual to begin on April 1, 2011, as a replacement for the expiration of the Company's captive insurance coverage with Berkshire Hathaway Energy Company (formerly known as MidAmerican Energy Holdings Company). The Oregon-allocated monthly accrual for property related losses was based on a 10-year average of actual property losses, with each year escalated by the Consumer Price Index to the Test Period. The Oregon-allocated monthly accrual for third-party liability losses was established based on an annual average of historical insurance claim payments from April 2005 to December 2009.

The adjustment in this case uses the Commission-approved methodology for self-insurance accruals from the 2010 Rate Case and every case since, updated for known and measurable changes for both property and liability losses. Premiums for both property and liability insurance have also been adjusted for known and measurable changes in the Test Period.

Consistent with the treatment from the 2010 Rate Case, the Company is using a 10- year average of property damages for the self-insurance reserve accrual, using the most recent 10-year time period. Total-company Non-T&D property insurance premiums were $4.9 million for the 12 months ended June 2021 and will be reduced slightly to $4.1 million for the Test Period.

As of June 2021, the Company's Oregon Property Insurance Reserves balance is sitting in a debit position. This means that the accruals recorded to this account have not been sufficient to cover actual expenses incurred. In other words, Oregon

[16] Order No. 10-473 at 5.

customers have been underpaying, to the extent that a significant balance of $20.9 million debit balance has accrued in this reserve account. To recover this expense for which Oregon customers have underpaid, the Company is proposing to amortize the outstanding balance over 10 years.

For third-party liability accrual, while this case continues to be calculating accrual levels using historical averages, consistent with the approved treatment in the 2010 Rate Case, the third-party liability accrual in this case is calculated based on a three-year average of historical gross expense net of third-party claim proceeds using the cash method. Total-company liability insurance premiums were $8.4 million for the 12 months ended June 2021 and will increase to $29.2 million for the Test Period. The increase in renewed liability insurance premiums effective August 15, 2021, is attributable to wildfire risk and other factors outside PacifiCorp's control.

Generation Overhaul Expense (page 4.6) – This adjustment normalizes generation overhaul expenses in the Base Period using a four-year average methodology. In this adjustment, overhaul expenses for the years ending June 2018 to June 2021 are restated to constant dollars to make them comparable prior to averaging.

Revenue-Sensitive Items & Uncollectible Accounts (page 4.7) – Uncollectible accounts expense is adjusted to the Test Period level by applying the historical uncollectible rate (Oregon uncollectible accounts expense in FERC Account 904 divided by Oregon general business revenues) to the normalized general business revenues in the Test Period. This adjustment also reflects pro forma changes to Franchise Tax, Resource Supplier Tax, and Public Utility Commission Fees based on the normalized level of general business revenue for the Test Period. Franchise Tax and Resource Supplier Tax is calculated based on three-year historical average tax factors derived using historical data from 2019 to 2021. This methodology was approved in the Company's 2021 Rate Case. The Public Utility Commission Fee will be updated to the recently approved rate of 0.43 percent in Reply.[17]

Memberships and Subscriptions (page 4.8) – This adjustment removes expenses in excess of Commission policy as outlined by the Commission order in docket UE 94.[18] National and regional trade organizations are recognized at 75 percent.

Meals and Entertainment Adjustment (page 4.9) – Order 20-473 in the Company's last general rate case adopted an adjustment of 50 percent of awards expense and 50 percent of meals and entertainment expense recognized as discretionary costs. This adjustment removes the previously disallowed costs from each expense category.

O&M Escalation (page 4.10) – This adjustment increases non-labor expenses for projected inflation through the Test Period. Projected increases or decreases in costs are based on IHS Markit indices, which provide a detailed assessment of the electric market both historically and into the future. The indices used are based solely on electric utility costs for materials and services, which exclude labor expense, according to the Uniform System of Accounts defined by FERC for major electric utilities. Use of the IHS Markit indices for escalation of non-labor O&M expenses is consistent with the Company's past rate cases, including its 2021 Rate Case in which the Commission approved a revenue requirement calculated using these indices.

[17] *In the matter of Public Utility Commission of Oregon, the imposition of Annual Regulatory Fees Upon Public Utilities Operating within the State of Oregon*, Docket No. UM 1012, Order No. 22-062 (Feb. 24, 2022).
[18] *In the matter of the Petition of PacifiCorp to Amend Order No. 98-191 Regarding Annual System Benefit Charge Adjustment*, Docket No. UE 94, Order No. 01-502 (June 22, 2001).

The IHS Markit indices are prepared at the FERC functional subcategory level and are denoted with their corresponding FERC account number. The individual FERC account level indices are then combined into broader indices representing operation, maintenance, or total O&M expenses. The IHS Markit study used to prepare this filing was the fourth quarter 2021 forecast, released January 25, 2022. The IHS Markit data is proprietary and subject to copyright protection, therefore the indices utilized in the Company's case are provided in Confidential Exhibit PAC/1005.

Vegetation and Wildfire Management O&M (page 4.11) – This adjustment removes wildfire mitigation and vegetation management expenses recorded in the Base Period, and then adds back in the expected levels of expense for the Test Period. As described above, please refer to the direct testimony of Mr. Berreth for a detailed discussion on the wildfire mitigation and vegetation management expenses in this case.

Transmission Wheeling - Facebook (page 4.12) – 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 incremental wheeling expense from non-Utah jurisdictions that should be situs-assigned to Utah.

C. Tab 5 – NPC Adjustments

Q. Please describe the information contained behind Tab 5 NPC Adjustments.

A. Tab 5 includes adjustments to items that are generally related to NPC, most of which are addressed separately in the Company's TAM filing. Specifically, adjustment page 5.1, NPC Adjustment, relates solely to NPC and recovery of these costs is being sought in the TAM rather than the general rate case. This adjustment is included for modeling and computational purposes only. For example, the Test Period revenue requirement includes revenue sensitive items such as Franchise Tax, Resource Supplier Tax, and Public Utility Commission Fees that are calculated off total general business revenues, including those collected for the purpose of recovering costs included in the TAM.

The NPC Index on page 5.0.1 is a brief overview of assumptions used to adjust NPC-related items. The numerical summary (page 5.0.2) identifies each adjustment made to actual expenses and that adjustment's impact on overall revenue requirement. Each column has a numerical reference to a corresponding page in the Report, which contains a lead sheet showing the affected FERC account(s), allocation factor(s), dollar amount, and a brief description of the adjustment.

Q. Please describe the adjustments included in Tab 5.

A. **NPC Adjustment (page 5.1) –** This 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, as well as normal hydro and temperature conditions for the Test Period. The Aurora study for this adjustment is based on forecasted loads for the Test Period. As previously described, this adjustment is included in the calculation of overall revenue requirement for computational purposes only; NPC is not part of the revenue requirement for the general rate case.

EIM BOSR and WRAP Fees (page 5.2)—This adjustment adds into Test Period results Energy Imbalance Market (EIM) Body of State Regulators (BOSR) fee, and Western Resource Adequacy Program (WRAP) fee estimated for calendar year 2023. For further details, please refer to the direct testimony of Mr. Michael G. Wilding.

D. Tab 6 – Depreciation and Amortization Expense Adjustments

Q. Please describe the information contained behind Tab 6 Depreciation and Amortization Adjustments.

A. Tab 6 includes the Depreciation and Amortization Adjustment Index followed by a numerical summary and the specific adjustments. The Adjustment Index on page 6.0.1 is a brief overview of assumptions used to adjust overall depreciation and amortization expense and reserve. The numerical summary (page 6.0.2) identifies each adjustment made to actual results and that adjustment's impact on the case. Each column has a numerical reference to a corresponding page in the Report, which contains a lead sheet showing the affected FERC account(s), allocation factor(s), dollar amount, and a brief description of the adjustment.

Q. Please describe the adjustments included in Tab 6.

A. **Depreciation and Amortization Expense (page 6.1)** – This adjustment reflects the incremental depreciation expense associated with the capital additions included in Adjustment 8.4, Pro Forma Plant Additions, and calculates the depreciation expense using the approved depreciation rates in dockets UM 1968 and UE 374, which became effective January 1, 2021. The annualized level of depreciation and amortization expense for the Test Period is calculated by applying the current composite depreciation and amortization rates to the December 2022 pro forma plant balances. Detailed calculation of the depreciation and amortization expense is provided on pages 6.1 through 6.1.13. The Company's proposal in this case to update certain coal-fired units' depreciable lives is not reflected in this adjustment, nor adjustment 6.2 below. This proposed change is reflected in adjustment 6.5 and discussed later in my testimony.

Depreciation and Amortization Reserve (page 6.2) – This adjustment steps forward the depreciation and amortization reserve from the Base Period 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 Base Period 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 adjustment has been added to the December 31, 2022 balance to reflect the impact of annualized depreciation expense in adjustment 6.1. The reserve balance calculations are detailed on pages 6.2 to 6.2.11. As stated above, any depreciation and amortization reserve impacts as a result of the Company's proposed changes to coal-fired generating units' depreciable lives are reflected in its own adjustment later in Tab 6.

Depreciation Allocation Correction Adjustment (page 6.3) – 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. This deferred amount is reflected in historical data on a system-allocated basis, but should be situs-assigned to Wyoming, Utah, and Idaho. This adjustment removes the steam-related deferred depreciation expense from historical data for Oregon's results of operations. Also being removed in this adjustment is the steam plant give-back reversal in Oregon established as part of the 2012 Depreciation Study. This give-back amount does not need to be incrementally added back into results, since the Company's last rate case incorporated into rates updated depreciation rates consistent with the 2018 Depreciation Study and reset annual depreciation expense to appropriate levels. The balance of give-back reversal being removed from the Base Period represents the amounts recorded in the last 6 months of 2020, prior to new depreciation rates becoming effective on January 1, 2021. Once new rates became effective on January 1, 2021, this give-back amount is no longer needed.

Repowering Buy-Downs Adjustment (page 6.4) – As a result of the all-party stipulation in docket UE 369, the undepreciated equipment balances from repowered assets were bought down in part with Excess Deferred Income Tax (EDIT) balances that resulted from the Tax Cut and Jobs Act (TCJA), and a portion of the Company's deferred FERC Open Access Transmission Tariff revenues. This adjustment corrects the allocation of expenses recorded in the Base Period as a result of the buy-downs for the Dunlap, and Foote Creek wind facilities. This adjustment also brings into results the amortization expense and accumulated reserves for wind facilities buy-downs for all repowered projects and adds into results pro forma amortization to reflect expense and reserves for these balances at the appropriate Test Year levels.

Coal-fired Units Depreciable Life Update (page 6.5) – In this proceeding, the Company is proposing to update the end of depreciable lives of Colstrip Units 3 and 4, Craig Unit 2, and Hayden Units 1 and 2. The Company's proposal would result in an acceleration of Colstrip's end of depreciable life to 2025.

Craig Unit 2's end of depreciable life would be extended by one year and 9 months, while Hayden Units 1 and 2 would see an extension of depreciable lives of 5 and 4 years, respectively. This adjustment reflects the change in depreciation expense by imputing the incremental annual depreciation expense between accrual amounts based on current depreciation rates of the select coal-fired facilities, and the proposed accrual amounts that would result in these units' respective net book value being fully depreciated for Oregon Customers by each unit's retirement dates proposed in the Company's 2021 IRP. Page 6.5.2 of Exhibit PAC/1002 provides a summary table of the change in end of depreciable life for each unit. Incremental reserves impact of the proposed change is reflected on an average basis.

The Company's proposal to update depreciable lives results in a net decrease in depreciation expense of $3.1 million on a total-company basis, which equates to approximately $810,500 on an Oregon-allocated basis. Net of impacts on updating depreciation reserves and tax impacts, the Oregon-allocated revenue requirement of this proposed depreciable lives update is approximately ($791,300). For details on the Company's proposal to update depreciable lives on specific coal-fired units, please refer to the direct testimony of Ms. Steward.

Bridger Coal Reclamation Costs (page 6.6) – This adjustment reflects the recovery of accelerated depreciation and reclamation costs for the Bridger Mine incremental to the amounts included in the cost of coal delivered to the Jim Bridger Plant approved in the Company's 2021 Rate Case. These costs are being recovered over the remaining depreciable life for Oregon customers of the Jim Bridger Plant. The adjustment in this case reflects the approved amounts of accelerated depreciation and reclamation costs for the Bridger Mine as approved in the 2021 Rate Case.

The above amounts being collected from Oregon customers are deferred to a regulatory liability, which will be debited with Oregon's share of reclamation costs when the Bridger Mine closes. This treatment allows the Company to recover the Bridger Mine while meeting the Senate Bill (SB) 1547 requirement of removing coal from Oregon electric utility rates prior to January 1, 2030.

E. Tab 7 – Tax Adjustments

Q. Please describe the information contained behind Tab 7 Tax Adjustments.

A. Tab 7 includes the Tax Adjustment Index followed by a numerical summary and the specific adjustments. The Adjustment Index (page 7.0.1) contains a brief overview of the tax adjustments included in this case. The numerical summary on pages 7.0.2 and 7.0.3 identifies each adjustment made to the various tax components and that adjustment's impact on the case. Each column has a numerical reference to a corresponding page in the Report, which contains a lead sheet showing the affected FERC account(s), allocation factor(s), dollar amount, and a brief description of the adjustment.

Q. Please describe the adjustments included in Tab 7.

A. **Interest True-Up (page 7.1) –** This adjustment details the adjustment to interest expense required to synchronize the Test Period interest expense with Test Period rate base. This is done by multiplying normalized net rate base by the Company's weighted cost of debt in this case.

Property Tax Expense (page 7.2) – Property tax expense for the Test Period is computed by adjusting accruals from the Base Period for known or anticipated changes in the assessed values of the Company's operating property and the corresponding effect such changes will have on property tax expense for the Test Period. For additional information on the Company's property tax estimation procedures and methodologies, please refer to Confidential Exhibit PAC/1003.

Production Tax Credit (PTC) (page 7.3) – The Company is entitled to recognize federal income tax credits as a result of placing renewable generating plants in service. The tax credit is based on the kilowatt-hours generated by the plants, and the credit can be taken for the first 10 years of generation from qualifying property. The PTC calculation reflects the credit based on the qualifying production as modeled for the Test Period NPC study. Customers receive the benefit of the PTCs in the Company's annual TAM filing. As with NPC in Adjustment 5.1, this adjustment is included for the purposes of calculating an overall revenue requirement only.

PowerTax Accumulated Deferred Income Tax (ADIT) Balance (page 7.4) This adjustment normalizes ADIT balances to an estimated pro forma level of rate base balance consistent with proforma capital additions, which are reflected through December 31, 2022. Additional line-item detail is included in the tax model that is provided with the Company's electronic workpapers.

Pro Forma Tax Balances Adjustment (page 7.5) – This adjustment normalizes the Schedule M items, deferred tax expense and related ADIT balances to an estimated pro forma level of expense for the Test Period. Additional line-item detail is included in the tax model that is provided with the Company's electronic work papers.

Wyoming Wind Generation Tax (page 7.6) – This adjustment normalizes the Wyoming Wind Generation Tax, which became effective January 1, 2012, into Test Period results. The Wyoming Wind Generation Tax is an excise tax levied upon production of electricity from wind resources in the state of Wyoming. The tax is levied 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 entity producing the electricity. New wind facilities are exempt from the tax for three years following the date the facility first produces electricity for sale. The tax is one dollar for each megawatt-hour (MWh) of electricity produced from wind resources at the point of interconnection with an electric transmission line.

Allowance for Funds Used During Construction (AFUDC) Equity (page 7.7) – This adjustment reflects the appropriate level of AFUDC equity into regulated results to align the tax schedule M with regulatory income. Per Commission Order 10-022, AFUDC equity in this case is included using flow-through tax treatment.[19]

TCJA EDIT Adjustment (page 7.8) – This adjustment adjusts the level of protected property EDIT amortization and adjusts the rate base for the test period consistent with pro forma capital additions, which are reflected through December 31, 2022.

[19] *In the matter of PacifiCorp, dba Pacific Power Request for a General Rate Revision*, Docket No. UE 210, Order No. 10-022 (Jan. 26, 2010).

Oregon Corporate Activity Tax (OCAT) & Metro Business Income Tax (Metro BIT) Adjustment (page 7.9) – This adjustment adds into base rates the forecasted OCAT and Metro BIT for the Test Period.

F. Tab 8 – Rate Base Adjustments

Q. Please describe the information contained behind Tab 8 Rate Base Adjustments.

A. Tab 8 includes the Rate Base Adjustment Index followed by a numerical summary and the specific adjustments. The Adjustment Index on page 8.0.1 begins with a brief overview of assumptions used to adjust rate base components. The numerical summary (pages 8.0.2 to 8.0.4) identifies each adjustment made to actual rate base and that adjustment's impact on the case. Each column has a numerical reference to a corresponding page in the Report, which contains a lead sheet showing the affected FERC account(s), allocation factor(s), dollar amount, and a brief description of the adjustment.

Q. Please describe each of the adjustments to the historical rate base balances.

A. **Cash Working Capital (page 8.1) –** This adjustment supports the calculation of cash working capital included in rate base based on the normalized results of operations for the Test Period. Total cash working capital is calculated by multiplying jurisdictional net lag days by the average daily cost of service. Net lag days in this case are based on a lead lag study prepared by PacifiCorp using calendar year 2015 information. An electronic version of the lead lag study is included as part of the Company's workpapers.

Trapper Mine Rate Base (page 8.2) – The Company owns a 29.14 percent interest in the Trapper Mine, which provides coal to the Craig generating plant. The normalized coal cost of Trapper includes all O&M costs but does not include a return on investment. This adjustment adds the Company's portion of the Trapper Mine plant investment to the rate base and reflects net plant to recognize the depreciation of the investment over time. This adjustment also walks the reclamation liability forward to December 2022. This adjustment was stipulated to and approved in docket UE 111[20] and has been included in all Oregon rate case filings since.

Jim Bridger Mine Rate Base (page 8.3) – The Company owns a two-thirds interest in the Bridger Coal Company, which supplies coal to the Jim Bridger generating plant. The Company's investment in Bridger Coal Company is recorded on the books of Pacific Minerals, Inc. Because of this ownership arrangement, the coal mine investment is not included in electric plant in service. This adjustment is necessary to properly reflect the Bridger Coal Company investment in rate base for the Company to earn a return on its investment. The normalized coal costs for Bridger Coal Company in NPC include the O&M costs of the mine but provide no return on investment. This adjustment adds the Company's portion of the pro forma December 31, 2022 net plant balance to rate base. This adjustment was stipulated to and approved in docket UE 111 and has been included in all Oregon rate case filings since.[21]

Pro Forma Plant Additions and Retirements (page 8.4) – To reasonably represent the cost of system infrastructure required to serve customers, the Company has identified capital projects that will be used and useful by December 31, 2022.

[209] *In the matter of the Revised Tariff Schedules Applicable to Electric Service Filed by PacifiCorp*, Docket No. UE 111, Order No. 00-580 (Sept. 25, 2000).
[21] *In the matter of the Revised Tariff Schedules Applicable to Electric Service Filed by PacifiCorp*, Docket No. UE 111, Order No. 00-580 (Sept. 25, 2000).

Capital additions by FERC functional category are listed on pages 8.4.19 to 8.4.26, indicating the in-service date and amount by project. This adjustment is based on plant balances as of December 31, 2022. As described earlier in my testimony, the accumulated depreciation reserve was adjusted forward to match the depreciation expense and retirements. Projects over $10 million (total-company basis) are described on pages 8.4.28 through 8.4.32 of the Report. Pro forma capital additions do not reflect any projects for wildfire restoration related to the Labor Day wildfires.

Customer Advances for Construction (page 8.5) – Customer advances were recorded in the Base Period to a corporate cost center location rather than state-specific locations. This adjustment corrects the allocation factors of customer advances.

Regulatory Asset and Liability Amortization (page 8.6) – This adjustment normalizes regulatory assets and liabilities from the Base Period to the Test Period. In addition, the Company is proposing to begin amortization of deferred Transportation Electrification Program (TEP) expenses from 2018 through 2021.[22] TEP expenses incurred after 2021 will be recovered through the System Benefits Charge.[23] The Company is proposing an amortization period of three years.

In this adjustment, the Company is also proposing to begin amortization of the deferred 2021 and 2022 REC revenues from the sale of Pryor Mountain RECs through Schedule 272 over a three-year amortization period. Additionally, since these

[22] *In the Matter of Pacificorp, dba Pacific Power, Application for Approval of Deferred Accounting for a Balancing Account Related to the Transportation Electrification Program*, Docket No. UM 1964, Application (Jul. 27, 2018).
[23] *In the matter of PacifiCorp dba Pacific Power 2020 Renewable Adjustment Clause*, Docket No. 369, Stipulation and Joint Testimony (Jan. 31, 2020).

specific REC revenues are forecasted to be fairly stable, the Company is proposing including into base rates effective January 1, 2023, an annual level of forecasted REC revenues for these sales into base rates.

Plant Held for Future Use (PHFU) (page 8.7) – This adjustment removes all PHFU assets from FERC account 105. The Company is making this adjustment in compliance with Order 01-787.[24]

Pension and Other Post-retirement Plan Balances Removal (page 8.8) – This adjustment removes the Company's net prepaid asset associated with its pension and other post-retirement welfare plans, net of associated accumulated deferred income taxes in unadjusted results. Per Order 15-226 in docket UM 1633, the net pension and post-retirement prepaid is not to be included in rate base for Oregon.[25]

Remove Rolling Hills (page 8.9) – This adjustment removes the gross plant, accumulated depreciation, and O&M amounts related to the Rolling Hills wind resource from the Base Period. Depreciation expense for Rolling Hills is removed in Adjustment 6.1, Depreciation/Amortization Expense Adjustment. This treatment is consistent with Order 08-548.[26]

Deer Creek Mine Adjustment (page 8.10) – Order 15-161 in docket UM 1712 addressed closure of the Deer Creek mine located in Utah and ruled on several

[24] *In the matter of PacifiCorp's Proposal to Restructure and Reprice its Services in Accordance with the Provisions of SB 1149,* Docket No. UE 116, Order No. 01-787 (Sept. 7, 2001)

[25] *In the matter of Public Utility Commission of Oregon, Investigation into Treatment of Pension Costs in Utility Rates,* Docket No. UM 1633, Order No. 15-226, 10-11 (Aug. 3, 2015).

[26] *In the atter of PacifiCorp dba Pacific Power 2009 Renewable Adjustment Clause Schedule 202,* Docket No. UE 200, Order No. 08-548, at 19-21 (Nov. 14, 2008), as supplemented and corrected by Order No, 08-554 (Nov. 25, 2008).

issues.[27] Order 20-473 in the Company's 2021 Rate Case approved for recovery of the Company's deferred unrecovered plant balances and associated closure costs in a separate tariff to be amortized over three years. The same order also determined that coal lease abandonment royalty costs were to be excluded from amounts being amortized on the basis that amounts were considered preliminary, and the timing of payment was not yet certain. The Company is, however, allowed to continue to defer these costs as approved in UM 1712, and may seek recovery in a future rate proceeding.[28] At the time this rate case was prepared, this royalty obligation remains outstanding. As such, the Company has not included that amount in this proceeding and will continue to defer this amount until amounts and payment timing can be accurately determined.

This adjustment removes all Deer Creek regulatory assets and closure costs from Base Period results, as these amounts are being recovered through a separate tariff rider, with interest at the modified blended Treasury rate. In addition, this adjustment adds into base rates the annual payment resulting from the Company's withdrawal from the 1974 Pension Trust associated with Deer Creek Mine. This amount was previously included in the TAM but was approved to be removed from the TAM to be included in base rates instead in Order 20-473.

Emissions Control Investment Adjustment (page 8.11) – This adjustment reflects in results rate base and return disallowances on emissions control investments as ordered in Order 20-473 in docket UE 374. This adjustment was prepared in the

[27] *In the matter of PacifiCorp dba Pacific Power, Application for Approval of the Deer Creek Mine Transaction*, Docket No. UM 1712, Order No. 15-161 (May 27, 2015).
[28] Order No. 20-473 at 88.

same manner as was included in the Company's compliance filing in the 2021 Rate Case.

Transmission Project Adjustment (page 8.12) – This adjustment reflects in results project cost disallowances on specific transmission projects as ordered in Order 20-473 in docket UE 374.

Cholla Unit 4 Retirement (page 8.13) – This adjustment removes from rate base balances related to Cholla Unit 4, which was retired on December 31, 2020. It also removes costs related to the O&M of this generation resource. These amounts are in Base Period results because the Company's base period in this case spans from July 2020 to June 2021—six months of which Cholla Unit 4 was still operational.

In the 2021 Rate Case, the Company's proposal to buy down the undepreciated plant balance and closure costs using TCJA deferred tax benefits was approved. Consequently, the revenue requirement calculation in this rate case also excludes all the regulatory assets associated with costs that have previously been approved to be bought down.

In this case, the Company is requesting recovery of additional closure cost items associated with the Cholla Unit 4 closure for which amounts were unknown and were not included in the previous case. Included in this case for recovery is deferred safe harbor lease termination payment and non-union severance expense. Additionally, as authorized in Order 20-473 the assessed property tax costs assigned to Cholla Unit 4 through the closure process have been deferred and are eligible for amortization, with interest to accumulate at the modified blended Treasury rate. This adjustment reflects the annual amortization expense associated with the incremental closure costs with a corresponding adjustment to the regulatory asset balance to reflect the 13-month average balance in the Test Period. As for deferred property tax costs, an annual amortization amount has also been calculated, but consistent with the ordered treatment in Order 20-473, the balance accrues interest at the modified blended Treasury rate and is removed from rate base.

Wind Project Deferrals Amortization (page 8.14) – This adjustment adds into Test Period results the amortization of deferred revenue requirement associated with Cedar Springs II wind project, which went into service in December 2020, one month prior to new rates from the 2021 Rate Case becoming effective. Cedar Springs II was part of Energy Vision 2020 wind projects determined to be prudent in the 2021 Rate Case (Order 20-473). The Company has a pending application for deferral treatment (docket UM 2134) of the revenue requirement for Cedar Springs II in front of the Commission, for the approximately one-month period that the facility was in service and serving customers, but its costs were not yet reflected in customer rates. The 2020 benefits of Cedar Springs II were included in rates for the 2020 TAM.

This adjustment also adds into Test Period results the amortization of deferred revenue requirement, net of 2021 NPC and PTC benefits, associated with TB Flats.[29] TB Flats was also part of the Energy Vision 2020 wind projects determined to be prudent in the 2021 Rate Case. The revenue requirement deferral for which the Company is seeking approval to begin amortization for is exclusively based on the incremental project costs that are not yet part of customer rates.

[29] 2022 NPC and PTC benefits for TB Flats are included in rates through the 2022 TAM.

For both deferred balances, the Company is proposing a three-year amortization period, starting January 1, 2023, to collect the deferred net revenue requirement associated with these wind projects not having been or being recovered in customer rates. Monthly amounts continue to accrue on these deferred balances through December 2022. Upon January 1, 2023, when new rates from the current case becomes effective, these deferrals will no longer be accruing additional amounts, as the full revenue requirement would be in base rates at that time.

Miscellaneous Rate Base (page 8.15) – This adjustment reflects the change in the fuel stock balance from the Base Period to the Test Period. This adjustment also reflects the working capital deposits that are offsets to fuel stock costs. In addition, balances for prepaid overhauls at the Lake Side, Chehalis, and Currant Creek natural gas plants are walked forward to reflect payments and transfers of capital to electric plant in service on a 13-month average basis through the Test Period. This adjustment was included in the stipulated settlement and approved in the Company's 2013 Rate Case, and have been included in every rate case since.[30]

Carbon Plant Retirement (page 8.16) – 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. This deferred amount includes a portion representing the accelerated depreciation expense associated with the early retirement of the Carbon plant. The Carbon plant was retired in April 2015. The deferral and amortization continued to be recorded in the Company's accounting books in the Base Period.

[30] Order No. 13-474 at 3 and App. A at 18.

However, this deferred expense is being recorded on a system-allocated basis, when it should be situs-assigned to Utah, Idaho, and Wyoming only. This adjustment removes the system-allocated amount from Oregon's historical results of operations. In the 2021 Rate Case, amortization of Oregon's excess decommissioning reserve, net of Oregon's allocation of Carbon's obsolete materials and supplies inventory, over five years was approved. This adjustment also reflects in results the amortization and forecasted balances for the Test Period.

Remove Labor Day Wildfire Restoration (page 8.17) – This adjustment removes from rate base the historical capital additions placed in-service as part of Labor Day Wildfire restoration efforts. This adjustment also removes the associated depreciation reserves from the Base Period. The Company is excluding capital projects related to the Labor Day wildfire events from this rate case at this time. The Company may seek recovery of these projects in a future proceeding.

G. Tab 9 – 2020 Protocol ECD

Q. Please describe the information contained behind Tab 9.

A. Tab 9 demonstrates the derivation of the 2020 Protocol ECD amount included in the current rate case.

Q. Please describe the ECD adjustment under 2020 Protocol.

A. Under 2020 Protocol, the Fixed ECD, as used in the 2017 Protocol, will continue for Idaho at $836,000 through the end of 2023. The Dynamic ECD, as used in the 2010 Protocol, will continue for Oregon through the end of 2023, capped at $11,000,000. No ECD adjustment exists for Utah or California. In Wyoming, the ECD terminated as of December 31, 2020.

Q. What is the Dynamic ECD?

A. The Dynamic ECD measures the embedded cost differentials between the production costs of pre-2005 resources, as defined in the 2010 Protocol, and the production cost of west hydro-electric resources and certain Mid-Columbia Contracts. The first part is computed by taking PacifiCorp's production costs related to pre-2005 resources, expressed in dollars per MWh, compared to production costs of west-side hydro-electric resources expressed in dollars per MWh with the difference multiplied by the hydro-electric resources' MWhs of production. The second part is computed by taking the differential between the pre-2005 resources' dollars per MWh compared to Mid-Columbia Contracts' costs on a dollars per MWh multiplied by the Mid-Columbia Contracts' MWhs.

H. Tab 10 – Allocation Factors

Q. Please describe the information contained behind Tab 10 Allocation Factors.

A. Tab 10 Allocation Factors summarizes the derivation of the inter-jurisdictional allocation factors using the 2020 Protocol.

I. Tabs B1 to B20

Q. Please describe the information contained behind Tabs B1 to B20.

A. Tabs B1 through B20 contain the historical results for the Base Period and are organized by major FERC function. The data contained in this section of the Report matches the unadjusted data found under Tab 2 – Results of Operations.

VI. CONCLUSION

Q. Please summarize your testimony.

A. I recommend that the Commission approve the requested $84.4 million increase and non-NPC revenue requirement of $1,044.8 million.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 399
Exhibit PAC/1001
Witness: Sherona L. Cheung

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Sherona L. Cheung

Revenue Requirement Summary

March 2022

PacifiCorp **PAGE 1.0**
OREGON
Normalized Results of Operations - 2020 PROTOCOL
Twelve Months Ending December 31, 2023

		(1)	(2)	(3)	(4)	(5)	(6)
			(3) - (1)	Ref. Page 1.3			(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	288,535,772	960,365,378	1,248,901,150	69,973,978	84,399,290	1,403,274,418
3	Interdepartmental		-	-			-
4	Special Sales	92,708,477	-	92,708,477			92,708,477
5	Other Operating Revenues		81,179,990	81,179,990			81,179,990
6	Total Operating Revenues	381,244,249	1,041,545,368	1,422,789,617	69,973,978	84,399,290	1,577,162,885
7							
8	Operating Expenses:						
9	Steam Production	154,813,423	83,222,619	238,036,042			238,036,042
10	Nuclear Production		-	-			-
11	Hydro Production		12,077,585	12,077,585			12,077,585
12	Other Power Supply	324,792,931	18,843,638	343,636,569			343,636,569
13	Transmission	41,801,335	18,785,840	60,587,175			60,587,175
14	Distribution		116,940,088	116,940,088			116,940,088
15	Customer Accounting		23,492,890	23,492,890		771,495	24,264,385
16	Customer Service & Info		6,029,376	6,029,376			6,029,376
17	Sales		-	-			-
18	Administrative & General		60,742,837	60,742,837			60,742,837
19							
20	Total O&M Expenses	521,407,688	340,134,873	861,542,561	-	771,495	862,314,056
21							
22	Depreciation		287,994,295	287,994,295			287,994,295
23	Amortization		43,237,301	43,237,301			43,237,301
24	Taxes Other Than Income		84,171,808	84,171,808		4,288,376	88,460,183
25	Income Taxes - Federal	(81,030,263)	19,734,117	(61,296,146)	14,027,403	15,904,856	(31,363,887)
26	Income Taxes - State	(6,363,420)	10,593,846	4,230,426	3,176,819	3,602,010	11,009,254
27	Income Taxes - Def Net		12,660,019	12,660,019			12,660,019
28	Investment Tax Credit Adj.		-	-			-
29	Misc Revenue & Expense		3,165	3,165			3,165
30							
31	Total Operating Expenses:	434,014,005	798,529,424	1,232,543,429	17,204,222	24,566,737	1,274,314,388
32							
33	Operating Rev For Return:	(52,769,756)	243,015,944	190,246,188	52,769,756	59,832,554	302,848,497
34							
35	Rate Base:						
36	Electric Plant In Service		8,852,783,093	8,852,783,093			8,852,783,093
37	Plant Held for Future Use		-	-			-
38	Misc Deferred Debits		67,300,330	67,300,330			67,300,330
39	Elec Plant Acq Adj		701,604	701,604			701,604
40	Pension		-	-			-
41	Prepayments		11,129,917	11,129,917			11,129,917
42	Fuel Stock		43,192,126	43,192,126			43,192,126
43	Material & Supplies		81,719,811	81,719,811			81,719,811
44	Working Capital		13,347,565	13,347,565			13,347,565
45	Weatherization Loans		-	-			-
46	Misc Rate Base		-	-			-
47							
48	Total Electric Plant:	-	9,070,174,446	9,070,174,446			9,070,174,446
49							
50	Rate Base Deductions:						
51	Accum Prov For Deprec		(3,571,364,011)	(3,571,364,011)			(3,571,364,011)
52	Accum Prov For Amort		(218,109,109)	(218,109,109)			(218,109,109)
53	Accum Def Income Tax		(643,480,187)	(643,480,187)			(643,480,187)
54	Unamortized ITC		(45,778)	(45,778)			(45,778)
55	Customer Adv For Const		(23,030,533)	(23,030,533)			(23,030,533)
56	Customer Service Deposits		-	-			-
57	Misc Rate Base Deductions		(415,023,294)	(415,023,294)			(415,023,294)
58							
59	Total Rate Base Deductions	-	(4,871,052,912)	(4,871,052,912)			(4,871,052,912)
60							
61	Total Rate Base:	-	4,199,121,534	4,199,121,534			4,199,121,534
62							
63	Return on Rate Base			4.531%			7.212%
64							
65	Return on Equity			4.668%			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	960,365,378	84,399,290	1,044,764,668
3	Interdepartmental	-		-
4	Special Sales	-		-
5	Other Operating Revenues	81,179,990		81,179,990
6	Total Operating Revenues	1,041,545,368	84,399,290	1,125,944,658
7				
8	Operating Expenses:			
9	Steam Production	83,222,619		83,222,619
10	Nuclear Production	-		-
11	Hydro Production	12,077,585		12,077,585
12	Other Power Supply	18,843,638		18,843,638
13	Transmission	18,785,840		18,785,840
14	Distribution	116,940,088		116,940,088
15	Customer Accounting	23,492,890	771,495	24,264,385
16	Customer Service & Info	6,029,376		6,029,376
17	Sales	-		-
18	Administrative & General	60,742,837		60,742,837
19				
20	Total O&M Expenses	340,134,873	771,495	340,906,368
21				
22	Depreciation	287,994,295		287,994,295
23	Amortization	43,237,301		43,237,301
24	Taxes Other Than Income	84,171,808	4,288,376	88,460,183
25	Income Taxes - Federal	19,734,117	15,904,856	35,638,973
26	Income Taxes - State	10,593,846	3,602,010	14,195,856
27	Income Taxes - Def Net	12,660,019		12,660,019
28	Investment Tax Credit Adj.	-		-
29	Misc Revenue & Expense	3,165		3,165
30				
31	Total Operating Expenses:	798,529,424	24,566,737	823,096,161
32				
33	Operating Rev For Return:	243,015,944	59,832,554	302,848,497
34				
35	Rate Base:			
36	Electric Plant In Service	8,852,783,093		8,852,783,093
37	Plant Held for Future Use	-		-
38	Misc Deferred Debits	67,300,330		67,300,330
39	Elec Plant Acq Adj	701,604		701,604
40	Pension	-		-
41	Prepayments	11,129,917		11,129,917
42	Fuel Stock	43,192,126		43,192,126
43	Material & Supplies	81,719,811		81,719,811
44	Working Capital	13,347,565		13,347,565
45	Weatherization Loans	-		-
46	Misc Rate Base	-		-
47				
48	Total Electric Plant:	9,070,174,446		9,070,174,446
49				
50	Rate Base Deductions:			
51	Accum Prov For Deprec	(3,571,364,011)		(3,571,364,011)
52	Accum Prov For Amort	(218,109,109)		(218,109,109)
53	Accum Def Income Tax	(643,480,187)		(643,480,187)
54	Unamortized ITC	(45,778)		(45,778)
55	Customer Adv For Const	(23,030,533)		(23,030,533)
56	Customer Service Deposits	-		-
57	Misc Rate Base Deductions	(415,023,294)		(415,023,294)
58				
59	Total Rate Base Deductions	(4,871,052,912)		(4,871,052,912)
60				
61	Total Rate Base:	4,199,121,534		4,199,121,534
62				
63	Return on Rate Base	5.787%		7.212%
64				
65	Return on Equity	7.073%		9.800%
66				
67	TAX CALCULATION:			
68	Operating Revenue	286,003,926	79,339,420	365,343,345
69	Other Deductions			
70	Interest (AFUDC)	(21,356,078)	-	(21,356,078)
71	Interest	84,048,729	-	84,048,729
72	Schedule "M" Additions	333,382,419	-	333,382,419
73	Schedule "M" Deductions	452,107,568	-	452,107,568
74	Income Before Tax	104,586,126	79,339,420	183,925,546
75				
76	State Income Taxes	10,593,846	3,602,010	14,195,856
77	Taxable Income	93,992,280	75,737,410	169,729,690
78				
79	Federal Income Taxes + Other	19,734,117	15,904,856	35,638,973

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	288,535,772	69,973,978	358,509,750
3	Interdepartmental	-		-
4	Special Sales	92,708,477		92,708,477
5	Other Operating Revenues	-		-
6	Total Operating Revenues	381,244,249	69,973,978	451,218,227
7				
8	Operating Expenses:			
9	Steam Production	154,813,423		154,813,423
10	Nuclear Production	-		-
11	Hydro Production	-		-
12	Other Power Supply	324,792,931		324,792,931
13	Transmission	41,801,335		41,801,335
14	Distribution	-		-
15	Customer Accounting	-	-	-
16	Customer Service & Info	-		-
17	Sales	-		-
18	Administrative & General	-		-
19				
20	Total O&M Expenses	521,407,688	-	521,407,688
21				
22	Depreciation	-		-
23	Amortization	-		-
24	Taxes Other Than Income	-	-	-
25	Income Taxes - Federal	(81,030,263)	14,027,403	(67,002,860)
26	Income Taxes - State	(6,363,420)	3,176,819	(3,186,602)
27	Income Taxes - Def Net	-		-
28	Investment Tax Credit Adj.	-		-
29	Misc Revenue & Expense	-		-
30				
31	Total Operating Expenses:	434,014,005	17,204,222	451,218,227
32				
33	Operating Rev For Return:	(52,769,756)	52,769,756	-
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	(140,163,439)	69,973,978	(70,189,462)
69	Other Deductions			
70	Interest (AFUDC)	-	-	-
71	Interest	-	-	-
72	Schedule "M" Additions	-	-	-
73	Schedule "M" Deductions	-	-	-
74	Income Before Tax	(140,163,439)	69,973,978	(70,189,462)
75				
76	State Income Taxes	(6,363,420)	3,176,819	(3,186,602)
77	Taxable Income	(133,800,019)	66,797,159	(67,002,860)
78				
79	Federal Income Taxes + Other	(81,030,263)	14,027,403	(67,002,860)

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	1,248,901,150	154,373,268	1,403,274,418
3	Interdepartmental	-		
4	Special Sales	92,708,477		
5	Other Operating Revenues	81,179,990		
6	Total Operating Revenues	1,422,789,617		
7				
8	Operating Expenses:			
9	Steam Production	238,036,042		
10	Nuclear Production	-		
11	Hydro Production	12,077,585		
12	Other Power Supply	343,636,569		
13	Transmission	60,587,175		
14	Distribution	116,940,088		
15	Customer Accounting	23,492,890	771,495	24,264,385
16	Customer Service & Info	6,029,376		
17	Sales	-		
18	Administrative & General	60,742,837		
19				
20	Total O&M Expenses	861,542,561		
21				
22	Depreciation	287,994,295		
23	Amortization	43,237,301		
24	Taxes Other Than Income	84,171,808	4,288,376	88,460,183
25	Income Taxes - Federal	(61,296,146)	29,932,259	(31,363,887)
26	Income Taxes - State	4,230,426	6,778,828	11,009,254
27	Income Taxes - Def Net	12,660,019		
28	Investment Tax Credit Adj.	-		
29	Misc Revenue & Expense	3,165		
30				
31	Total Operating Expenses:	1,232,543,429	41,770,958	1,274,314,388
32				
33	Operating Rev For Return:	190,246,188	112,602,309	302,848,497
34				
35	Rate Base:			
36	Electric Plant In Service	8,852,783,093		
37	Plant Held for Future Use	-		
38	Misc Deferred Debits	67,300,330		
39	Elec Plant Acq Adj	701,604		
40	Pensions	-		
41	Prepayments	11,129,917		
42	Fuel Stock	43,192,126		
43	Material & Supplies	81,719,811		
44	Working Capital	13,347,565		
45	Weatherization Loans	-		
46	Misc Rate Base	-		
47				
48	Total Electric Plant:	9,070,174,446	-	9,070,174,446
49				
50	Rate Base Deductions:			
51	Accum Prov For Deprec	(3,571,364,011)		
52	Accum Prov For Amort	(218,109,109)		
53	Accum Def Income Tax	(643,480,187)		
54	Unamortized ITC	(45,778)		
55	Customer Adv For Const	(23,030,533)		
56	Customer Service Deposits	-		
57	Misc Rate Base Deductions	(415,023,294)		
58				
59	Total Rate Base Deductions	(4,871,052,912)	-	(4,871,052,912)
60				
61	Total Rate Base:	4,199,121,534	-	4,199,121,534
62				
63	Return on Rate Base	4.531%		7.212%
64				
65	Return on Equity	4.668%		9.800%
66				
67	TAX CALCULATION:			
68	Operating Revenue	145,840,487	149,313,397	295,153,884
69	Other Deductions			
70	Interest (AFUDC)	(21,356,078)	-	(21,356,078)
71	Interest	84,048,729	-	84,048,729
72	Schedule "M" Additions	333,382,419	-	333,382,419
73	Schedule "M" Deductions	452,107,568	-	452,107,568
74	Income Before Tax	(35,577,313)	149,313,397	113,736,084
75				
76	State Income Taxes	4,230,426	6,778,828	11,009,254
77	Taxable Income	(39,807,739)	142,534,569	102,726,830
78				
79	Federal Income Taxes + Other	(61,296,146)	29,932,259	(31,363,887)

Pacificorp
Oregon General Rate Case
Adjustment Summary
Twelve Months Ending December 31, 2023

	Exhibit PAC/1002		Exhibit PAC/1002			
			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	(61,204,592)	1,766,619	-	-
3 Interdepartmental	-	-	-	-	-	-
4 Special Sales	212,315,668	52,145,322	-	-	40,563,155	-
5 Other Operating Revenues	227,962,549	74,239,841	4,704,600	-	-	-
6 Total Operating Revenues	5,521,910,467	1,434,724,286	(56,499,992)	1,766,619	40,563,155	-
7						
8 Operating Expenses:						
9 Steam Production	997,145,306	256,305,884	-	5,165,696	(14,027,757)	3,634,603
10 Nuclear Production	-	-	-	-	-	-
11 Hydro Production	76,270,911	19,884,087	-	(7,806,503)	-	-
12 Other Power Supply	1,076,832,156	266,678,359	-	2,779,918	74,475,770	-
13 Transmission	220,828,048	57,410,559	-	155,610	3,021,006	-
14 Distribution	227,788,851	88,583,363	-	28,356,724	-	-
15 Customer Accounting	70,180,739	22,022,443	-	1,470,447	-	-
16 Customer Service & Info	116,029,408	5,610,498	-	418,878	-	-
17 Sales	-	-	-	-	-	-
18 Administrative & General	296,924,361	86,907,150	-	(25,183,567)	-	-
19						
20 Total O&M Expenses	3,081,999,779	803,402,344	-	5,357,203	63,469,020	3,634,603
21						
22 Depreciation	1,035,081,277	232,580,644	-	-	-	58,506,685
23 Amortization	61,823,778	16,306,178	-	-	-	24,557,686
24 Taxes Other Than Income	212,196,714	79,098,063	-	(1,473,948)	-	-
25 Income Taxes - Federal	(28,741,917)	8,249,843	(11,325,777)	1,450,480	(4,594,138)	(13,912,304)
26 Income Taxes - State	26,781,277	9,304,835	(2,564,975)	328,494	(1,040,445)	(3,150,752)
27 Income Taxes - Def Net	(64,900,993)	(21,612,618)	-	(2,473,765)	-	(259,669)
28 Investment Tax Credit Adj.	(1,703,368)	-	-	-	-	-
29 Misc Revenue & Expense	(1,733,836)	(99,173)	-	102,338	-	-
30						
31 Total Operating Expenses:	4,320,802,712	1,127,230,117	(13,890,752)	3,290,802	57,834,436	69,376,249
32						
33 Operating Rev For Return:	1,201,107,755	307,494,169	(42,609,240)	(1,524,183)	(17,271,281)	(69,376,249)
34						
35 Rate Base:						
36 Electric Plant In Service	31,317,729,025	8,567,379,441	-	-	-	-
37 Plant Held for Future Use	23,896,248	9,657,872	-	-	-	-
38 Misc Deferred Debits	962,744,647	193,776,856	-	-	-	-
39 Elec Plant Acq Adj	14,875,820	1,753,028	-	-	-	-
40 Pensions	28,656,862	7,786,953	-	-	-	-
41 Prepayments	67,554,352	11,129,917	-	-	-	-
42 Fuel Stock	201,471,836	50,505,232	-	-	-	-
43 Material & Supplies	273,026,865	83,112,462	-	-	-	-
44 Working Capital	46,340,902	13,995,191	(131,295)	53,519	546,651	(126,926)
45 Weatherization Loans	199,224,237	-	-	-	-	-
46 Misc Rate Base	-	-	-	-	-	-
47						
48 Total Electric Plant:	33,135,520,794	8,939,096,950	(131,295)	53,519	546,651	(126,926)
49						
50 Rate Base Deductions:						
51 Accum Prov For Deprec	(9,626,761,743)	(2,815,387,372)	-	-	-	(752,230,479)
52 Accum Prov For Amort	(691,673,798)	(201,534,614)	-	-	-	(16,574,495)
53 Accum Def Income Tax	(2,565,819,019)	(623,521,952)	-	(9,430,521)	-	(602,563)
54 Unamortized ITC	(2,245,487)	(50,351)	-	-	-	-
55 Customer Adv For Const	(104,109,027)	(28,119,926)	-	-	-	-
56 Customer Service Deposits	-	-	-	-	-	-
57 Misc Rate Base Deductions	(2,269,895,491)	(489,871,272)	-	38,356,344	-	(7,266,788)
58						
59 Total Rate Base Deductions	(15,260,504,564)	(4,158,485,487)	-	28,925,824	-	(776,674,325)
60						
61 Total Rate Base:	17,875,016,231	4,780,611,463	(131,295)	28,979,343	546,651	(776,801,251)
62						
63 Return on Rate Base		6.432%	-0.891%	-0.065%	-0.360%	-0.735%
64						
65 Return on Equity		8.307%	-1.706%	-0.125%	-0.688%	-1.406%
66						
67 TAX CALCULATION:						
68 Operating Revenue		303,436,230	(56,499,992)	(2,218,974)	(22,905,864)	(86,698,974)
69 Other Deductions						
70 Interest (AFUDC)		(20,265,333)	-	-	-	-
71 Interest		96,206,794	(2,745)	606,921	11,431	(16,243,007)
72 Schedule "M" Additions		406,229,218	-	10,061,436	-	1,056,147
73 Schedule "M" Deductions		428,771,671	-	-	-	-
74 Income Before Tax		204,952,316	(56,497,246)	7,235,540	(22,917,295)	(69,399,819)
75						
76 State Income Taxes		9,304,835	(2,564,975)	328,494	(1,040,445)	(3,150,752)
77 Taxable Income		195,647,481	(53,932,271)	6,907,046	(21,876,850)	(66,249,067)
78						
79 Federal Income Taxes + Other		8,249,843	(11,325,777)	1,450,480	(4,594,138)	(13,912,304)
APPROXIMATE PRICE CHANGE		51,101,359	58,398,993	4,983,679	23,732,287	18,304,908

Pacificorp
Oregon General Rate Case
Adjustment Summary
Twelve Months Ending December 31, 2023

		Exhibit PAC/1002		
		Tab 7	Tab 8	OR Allocated
		Tax Adjustments	Rate Base Adjustments	Results of Operations December 2023
1	Operating Revenues:			
2	General Business Revenues	-	-	1,248,901,150
3	Interdepartmental	-	-	-
4	Special Sales	-	-	92,708,477
5	Other Operating Revenues	-	2,235,548	81,179,990
6	Total Operating Revenues	-	2,235,548	1,422,789,617
7				
8	Operating Expenses:			
9	Steam Production	-	(13,042,384)	238,036,042
10	Nuclear Production	-	-	-
11	Hydro Production	-	-	12,077,585
12	Other Power Supply	-	(297,478)	343,636,569
13	Transmission	-	-	60,587,175
14	Distribution	-	-	116,940,088
15	Customer Accounting	-	-	23,492,890
16	Customer Service & Info	-	-	6,029,376
17	Sales	-	-	-
18	Administrative & General	-	(980,746)	60,742,837
19				
20	Total O&M Expenses	-	(14,320,608)	861,542,561
21				
22	Depreciation	-	(3,093,033)	287,994,295
23	Amortization	-	2,373,437	43,237,301
24	Taxes Other Than Income	6,547,693	-	84,171,808
25	Income Taxes - Federal	(46,790,008)	5,625,758	(61,296,146)
26	Income Taxes - State	79,191	1,274,079	4,230,426
27	Income Taxes - Def Net	40,629,511	(3,623,440)	12,660,019
28	Investment Tax Credit Adj.	-	-	-
29	Misc Revenue & Expense	-	-	3,165
30				
31	Total Operating Expenses:	466,386	(11,763,808)	1,232,543,429
32				
33	Operating Rev For Return:	(466,386)	13,999,357	190,246,188
34				
35	Rate Base:			
36	Electric Plant In Service	-	285,403,652	8,852,783,093
37	Plant Held for Future Use	-	(9,657,872)	-
38	Misc Deferred Debits	-	(126,476,526)	67,300,330
39	Elec Plant Acq Adj	-	(1,051,423)	701,604
40	Pensions	-	(7,786,953)	-
41	Prepayments	-	-	11,129,917
42	Fuel Stock	-	(7,313,106)	43,192,126
43	Material & Supplies	-	(1,392,651)	81,719,811
44	Working Capital	(379,622)	(609,953)	13,347,565
45	Weatherization Loans	-	-	-
46	Misc Rate Base	-	-	-
47				
48	Total Electric Plant:	(379,622)	131,115,168	9,070,174,446
49				
50	Rate Base Deductions:			
51	Accum Prov For Deprec	-	(3,746,161)	(3,571,364,011)
52	Accum Prov For Amort	-	-	(218,109,109)
53	Accum Def Income Tax	(50,169,049)	40,243,899	(643,480,187)
54	Unamortized ITC	4,573	-	(45,778)
55	Customer Adv For Const	-	5,089,393	(23,030,533)
56	Customer Service Deposits	-	-	-
57	Misc Rate Base Deductions	27,572,240	16,186,182	(415,023,294)
58				
59	Total Rate Base Deductions	(22,592,236)	57,773,313	(4,871,052,912)
60				
61	Total Rate Base:	(22,971,858)	188,888,481	4,199,121,534
62				
63	Return on Rate Base	0.013%	0.136%	4.531%
64				
65	Return on Equity	0.026%	0.260%	4.668%
66				
67	TAX CALCULATION:			
68	Operating Revenue	(6,547,693)	17,275,753	145,840,487
69	Other Deductions			
70	Interest (AFUDC)	(1,090,745)	-	(21,356,078)
71	Interest	(480,344)	3,949,681	84,048,729
72	Schedule "M" Additions	(93,710,028)	9,745,647	333,382,419
73	Schedule "M" Deductions	28,327,582	(4,991,685)	452,107,568
74	Income Before Tax	(127,014,213)	28,063,404	(35,577,313)
75				
76	State Income Taxes	79,191	1,274,079	4,230,426
77	Taxable Income	(127,093,404)	26,789,326	(39,807,739)
78				
79	Federal Income Taxes + Other	(46,790,008)	5,625,758	(61,296,146)
	APPROXIMATE PRICE CHANGE	(1,631,974)	(515,983)	154,373,268

Docket No. UE 399
Exhibit PAC/1002
Witness: Sherona L. Cheung

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Sherona L. Cheung

Oregon Results of Operations – December 2023

March 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	1,403,274,418	Page 1.1
(2)	Normalized General Business Revenues	1,248,901,150	Page 1.1
(3)	2020 Protocol Price Change	**154,373,268**	Page 1.1

PacifiCorp
OREGON
Normalized Results of Operations - 2020 PROTOCOL
Twelve Months Ending December 31, 2023

	(1)	(2)	(3)	(4)	(5)	(6)
		(3) - (1)	Ref. Page 1.4			(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	288,535,772	960,365,378	1,248,901,150	69,973,978	84,399,290	1,403,274,418
3 Interdepartmental		-	-			-
4 Special Sales	92,708,477	-	92,708,477			92,708,477
5 Other Operating Revenues		81,179,990	81,179,990			81,179,990
6 Total Operating Revenues	381,244,249	1,041,545,368	1,422,789,617	69,973,978	84,399,290	1,577,162,885
7						
8 Operating Expenses:						
9 Steam Production	154,813,423	83,222,619	238,036,042			238,036,042
10 Nuclear Production		-	-			-
11 Hydro Production		12,077,585	12,077,585			12,077,585
12 Other Power Supply	324,792,931	18,843,638	343,636,569			343,636,569
13 Transmission	41,801,335	18,785,840	60,587,175			60,587,175
14 Distribution		116,940,088	116,940,088			116,940,088
15 Customer Accounting		23,492,890	23,492,890		771,495	24,264,385
16 Customer Service & Info		6,029,376	6,029,376			6,029,376
17 Sales		-	-			-
18 Administrative & General		60,742,837	60,742,837			60,742,837
19						
20 Total O&M Expenses	521,407,688	340,134,873	861,542,561	-	771,495	862,314,056
21						
22 Depreciation		287,994,295	287,994,295			287,994,295
23 Amortization		43,237,301	43,237,301			43,237,301
24 Taxes Other Than Income		84,171,808	84,171,808		4,288,376	88,460,183
25 Income Taxes - Federal	(81,030,263)	19,734,117	(61,296,146)	14,027,403	15,904,856	(31,363,887)
26 Income Taxes - State	(6,363,420)	10,593,846	4,230,426	3,176,819	3,602,010	11,009,254
27 Income Taxes - Def Net		12,660,019	12,660,019			12,660,019
28 Investment Tax Credit Adj.		-	-			-
29 Misc Revenue & Expense		3,165	3,165			3,165
30						
31 Total Operating Expenses:	434,014,005	798,529,424	1,232,543,429	17,204,222	24,566,737	1,274,314,388
32						
33 Operating Rev For Return:	(52,769,756)	243,015,944	190,246,188	52,769,756	59,832,554	302,848,497
34						
35 Rate Base:						
36 Electric Plant In Service		8,852,783,093	8,852,783,093			8,852,783,093
37 Plant Held for Future Use		-	-			-
38 Misc Deferred Debits		67,300,330	67,300,330			67,300,330
39 Elec Plant Acq Adj		701,604	701,604			701,604
40 Pension		-	-			-
41 Prepayments		11,129,917	11,129,917			11,129,917
42 Fuel Stock		43,192,126	43,192,126			43,192,126
43 Material & Supplies		81,719,811	81,719,811			81,719,811
44 Working Capital		13,347,565	13,347,565			13,347,565
45 Weatherization Loans		-	-			-
46 Misc Rate Base		-	-			-
47						
48 Total Electric Plant:	-	9,070,174,446	9,070,174,446			9,070,174,446
49						
50 Rate Base Deductions:						
51 Accum Prov For Deprec		(3,571,364,011)	(3,571,364,011)			(3,571,364,011)
52 Accum Prov For Amort		(218,109,109)	(218,109,109)			(218,109,109)
53 Accum Def Income Tax		(643,480,187)	(643,480,187)			(643,480,187)
54 Unamortized ITC		(45,778)	(45,778)			(45,778)
55 Customer Adv For Const		(23,030,533)	(23,030,533)			(23,030,533)
56 Customer Service Deposits		-	-			-
57 Misc Rate Base Deductions		(415,023,294)	(415,023,294)			(415,023,294)
58						
59 Total Rate Base Deductions	-	(4,871,052,912)	(4,871,052,912)			(4,871,052,912)
60						
61 Total Rate Base:	-	4,199,121,534	4,199,121,534			4,199,121,534
62						
63 Return on Rate Base			4.531%			7.212%
64						
65 Return on Equity			4.668%			9.800%

Ref. Page 1.2

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	960,365,378	84,399,290	1,044,764,668
3	Interdepartmental	-		-
4	Special Sales	-		-
5	Other Operating Revenues	81,179,990		81,179,990
6	Total Operating Revenues	1,041,545,368	84,399,290	1,125,944,658
7				
8	Operating Expenses:			
9	Steam Production	83,222,619		83,222,619
10	Nuclear Production	-		-
11	Hydro Production	12,077,585		12,077,585
12	Other Power Supply	18,843,638		18,843,638
13	Transmission	18,785,840		18,785,840
14	Distribution	116,940,088		116,940,088
15	Customer Accounting	23,492,890	771,495	24,264,385
16	Customer Service & Info	6,029,376		6,029,376
17	Sales	-		-
18	Administrative & General	60,742,837		60,742,837
19				
20	Total O&M Expenses	340,134,873	771,495	340,906,368
21				
22	Depreciation	287,994,295		287,994,295
23	Amortization	43,237,301		43,237,301
24	Taxes Other Than Income	84,171,808	4,288,376	88,460,183
25	Income Taxes - Federal	19,734,117	15,904,856	35,638,973
26	Income Taxes - State	10,593,846	3,602,010	14,195,856
27	Income Taxes - Def Net	12,660,019		12,660,019
28	Investment Tax Credit Adj.	-		-
29	Misc Revenue & Expense	3,165		3,165
30				
31	Total Operating Expenses:	798,529,424	24,566,737	823,096,161
32				
33	Operating Rev For Return:	243,015,944	59,832,554	302,848,497
34				
35	Rate Base:			
36	Electric Plant In Service	8,852,783,093		8,852,783,093
37	Plant Held for Future Use	-		-
38	Misc Deferred Debits	67,300,330		67,300,330
39	Elec Plant Acq Adj	701,604		701,604
40	Pension	-		-
41	Prepayments	11,129,917		11,129,917
42	Fuel Stock	43,192,126		43,192,126
43	Material & Supplies	81,719,811		81,719,811
44	Working Capital	13,347,565		13,347,565
45	Weatherization Loans	-		-
46	Misc Rate Base	-		-
47				
48	Total Electric Plant:	9,070,174,446		9,070,174,446
49				
50	Rate Base Deductions:			
51	Accum Prov For Deprec	(3,571,364,011)		(3,571,364,011)
52	Accum Prov For Amort	(218,109,109)		(218,109,109)
53	Accum Def Income Tax	(643,480,187)		(643,480,187)
54	Unamortized ITC	(45,778)		(45,778)
55	Customer Adv For Const	(23,030,533)		(23,030,533)
56	Customer Service Deposits	-		-
57	Misc Rate Base Deductions	(415,023,294)		(415,023,294)
58				
59	Total Rate Base Deductions	(4,871,052,912)		(4,871,052,912)
60				
61	Total Rate Base:	4,199,121,534		4,199,121,534
62				
63	Return on Rate Base	5.787%		7.212%
64				
65	Return on Equity	7.073%		9.800%
66				
67	TAX CALCULATION:			
68	Operating Revenue	286,003,926	79,339,420	365,343,345
69	Other Deductions			
70	Interest (AFUDC)	(21,356,078)	-	(21,356,078)
71	Interest	84,048,729	-	84,048,729
72	Schedule "M" Additions	333,382,419	-	333,382,419
73	Schedule "M" Deductions	452,107,568	-	452,107,568
74	Income Before Tax	104,586,126	79,339,420	183,925,546
75				
76	State Income Taxes	10,593,846	3,602,010	14,195,856
77	Taxable Income	93,992,280	75,737,410	169,729,690
78				
79	Federal Income Taxes + Other	19,734,117	15,904,856	35,638,973

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	288,535,772	69,973,978	358,509,750
3	Interdepartmental	-		-
4	Special Sales	92,708,477		92,708,477
5	Other Operating Revenues	-		-
6	Total Operating Revenues	381,244,249	69,973,978	451,218,227
7				
8	Operating Expenses:			
9	Steam Production	154,813,423		154,813,423
10	Nuclear Production	-		-
11	Hydro Production	-		-
12	Other Power Supply	324,792,931		324,792,931
13	Transmission	41,801,335		41,801,335
14	Distribution	-		-
15	Customer Accounting	-	-	-
16	Customer Service & Info	-		-
17	Sales	-		-
18	Administrative & General	-		-
19				
20	Total O&M Expenses	521,407,688	-	521,407,688
21				
22	Depreciation	-		-
23	Amortization	-		-
24	Taxes Other Than Income	-	-	-
25	Income Taxes - Federal	(81,030,263)	14,027,403	(67,002,860)
26	Income Taxes - State	(6,363,420)	3,176,819	(3,186,602)
27	Income Taxes - Def Net	-		-
28	Investment Tax Credit Adj.	-		-
29	Misc Revenue & Expense	-		-
30				
31	Total Operating Expenses:	434,014,005	17,204,222	451,218,227
32				
33	Operating Rev For Return:	(52,769,756)	52,769,756	-
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	(140,163,439)	69,973,978	(70,189,462)
69	Other Deductions			
70	Interest (AFUDC)	-	-	-
71	Interest	-	-	-
72	Schedule "M" Additions	-	-	-
73	Schedule "M" Deductions	-	-	-
74	Income Before Tax	(140,163,439)	69,973,978	(70,189,462)
75				
76	State Income Taxes	(6,363,420)	3,176,819	(3,186,602)
77	Taxable Income	(133,800,019)	66,797,159	(67,002,860)
78				
79	Federal Income Taxes + Other	(81,030,263)	14,027,403	(67,002,860)

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	1,248,901,150	154,373,268	1,403,274,418
3	Interdepartmental	-		
4	Special Sales	92,708,477		
5	Other Operating Revenues	81,179,990		
6	Total Operating Revenues	1,422,789,617		
7				
8	Operating Expenses:			
9	Steam Production	238,036,042		
10	Nuclear Production	-		
11	Hydro Production	12,077,585		
12	Other Power Supply	343,636,569		
13	Transmission	60,587,175		
14	Distribution	116,940,088		
15	Customer Accounting	23,492,890	771,495	24,264,385
16	Customer Service & Info	6,029,376		
17	Sales	-		
18	Administrative & General	60,742,837		
19				
20	Total O&M Expenses	861,542,561		
21				
22	Depreciation	287,994,295		
23	Amortization	43,237,301		
24	Taxes Other Than Income	84,171,808	4,288,376	88,460,183
25	Income Taxes - Federal	(61,296,146)	29,932,259	(31,363,887)
26	Income Taxes - State	4,230,426	6,778,828	11,009,254
27	Income Taxes - Def Net	12,660,019		
28	Investment Tax Credit Adj.	-		
29	Misc Revenue & Expense	3,165		
30				
31	Total Operating Expenses:	1,232,543,429	41,770,958	1,274,314,388
32				
33	Operating Rev For Return:	190,246,188	112,602,309	302,848,497
34				
35	Rate Base:			
36	Electric Plant In Service	8,852,783,093		
37	Plant Held for Future Use	-		
38	Misc Deferred Debits	67,300,330		
39	Elec Plant Acq Adj	701,604		
40	Pensions	-		
41	Prepayments	11,129,917		
42	Fuel Stock	43,192,126		
43	Material & Supplies	81,719,811		
44	Working Capital	13,347,565		
45	Weatherization Loans	-		
46	Misc Rate Base	-		
47				
48	Total Electric Plant:	9,070,174,446	-	9,070,174,446
49				
50	Rate Base Deductions:			
51	Accum Prov For Deprec	(3,571,364,011)		
52	Accum Prov For Amort	(218,109,109)		
53	Accum Def Income Tax	(643,480,187)		
54	Unamortized ITC	(45,778)		
55	Customer Adv For Const	(23,030,533)		
56	Customer Service Deposits	-		
57	Misc Rate Base Deductions	(415,023,294)		
58				
59	Total Rate Base Deductions	(4,871,052,912)	-	(4,871,052,912)
60				
61	Total Rate Base:	4,199,121,534	-	4,199,121,534
62				
63	Return on Rate Base	4.531%		7.212%
64				
65	Return on Equity	4.668%		9.800%
66				
67	TAX CALCULATION:			
68	Operating Revenue	145,840,487	149,313,397	295,153,884
69	Other Deductions			
70	Interest (AFUDC)	(21,356,078)	-	(21,356,078)
71	Interest	84,048,729	-	84,048,729
72	Schedule "M" Additions	333,382,419	-	333,382,419
73	Schedule "M" Deductions	452,107,568	-	452,107,568
74	Income Before Tax	(35,577,313)	149,313,397	113,736,084
75				
76	State Income Taxes	4,230,426	6,778,828	11,009,254
77	Taxable Income	(39,807,739)	142,534,569	102,726,830
78				
79	Federal Income Taxes + Other	(61,296,146)	29,932,259	(31,363,887)

PacifiCorp
OREGON
Normalized Results of Operations - 2020 PROTOCOL
Twelve Months Ending December 31, 2023

Net Rate Base	$	4,199,121,534	Ref. Page 1.1
Return on Rate Base Requested		7.21%	Ref. Page 2.0
Revenues Required to Earn Requested Return		302,848,497	
Less Current Operating Revenues		(190,246,188)	
Increase to Current Revenues		112,602,309	
Net to Gross Bump-up		137.10%	
Price Change Required for Requested Return	$	154,373,268	
Requested Price Change	$	154,373,268	
Uncollectible Percent		0.500%	Ref. Page 1.6
Increased Uncollectible Expense	$	771,495	
Requested Price Change	$	154,373,268	
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		0.350%	Ref. Page 1.6
Increase Taxes Other Than Income	$	4,288,376	
Requested Price Change	$	154,373,268	
Uncollectible Expense		(771,495)	
Taxes Other Than Income		(4,288,376)	
Income Before Taxes	$	149,313,397	
State Effective Tax Rate		4.54%	Ref. Page 2.0
State Income Taxes	$	6,778,828	
Taxable Income	$	142,534,569	
Federal Income Tax Rate		21.00%	Ref. Page 2.0
Federal Income Taxes	$	29,932,259	
Operating Income		100.000%	
Net Operating Income		72.942%	Ref. Page 1.6
Net to Gross Bump-Up		137.10%	

PacifiCorp
OREGON
Normalized Results of Operations - 2020 PROTOCOL
Twelve Months Ending December 31, 2023

Operating Revenue	100.000%	
Operating Deductions		
Uncollectible Accounts	0.500%	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	0.350%	
Sub-Total	96.722%	
State Income Tax @ 4.54%	4.391%	
Sub-Total	92.331%	
Federal Income Tax @ 21.00%	19.390%	
Net Operating Income	72.942%	

(1) Uncollectible Accounts = $\frac{6{,}241{,}502}{1{,}248{,}901{,}150}$

6,241,502 — Pg 2.11, OREGON Situs from Account 904
1,248,901,150 — 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	(61,204,592)	1,766,619	-	-
3 Interdepartmental	-	-	-	-	-	-
4 Special Sales	212,315,668	52,145,322	-	-	40,563,155	-
5 Other Operating Revenues	227,962,549	74,239,841	4,704,600	-	-	-
6 Total Operating Revenues	5,521,910,467	1,434,724,286	(56,499,992)	1,766,619	40,563,155	-
7						
8 Operating Expenses:						
9 Steam Production	997,145,306	256,305,884	-	5,165,696	(14,027,757)	3,634,603
10 Nuclear Production	-	-	-	-	-	-
11 Hydro Production	76,270,911	19,884,087	-	(7,806,503)	-	-
12 Other Power Supply	1,076,832,156	266,678,359	-	2,779,918	74,475,770	-
13 Transmission	220,828,048	57,410,559	-	155,610	3,021,006	-
14 Distribution	227,788,851	88,583,363	-	28,356,724	-	-
15 Customer Accounting	70,180,739	22,022,443	-	1,470,447	-	-
16 Customer Service & Info	116,029,408	5,610,498	-	418,878	-	-
17 Sales	-	-	-	-	-	-
18 Administrative & General	296,924,361	86,907,150	-	(25,183,567)	-	-
19						
20 Total O&M Expenses	3,081,999,779	803,402,344	-	5,357,203	63,469,020	3,634,603
21						
22 Depreciation	1,035,081,277	232,580,644	-	-	-	58,506,685
23 Amortization	61,823,778	16,306,178	-	-	-	24,557,686
24 Taxes Other Than Income	212,196,714	79,098,063	-	(1,473,948)	-	-
25 Income Taxes - Federal	(28,741,917)	8,249,843	(11,325,777)	1,450,480	(4,594,138)	(13,912,304)
26 Income Taxes - State	26,781,277	9,304,835	(2,564,975)	328,494	(1,040,445)	(3,150,752)
27 Income Taxes - Def Net	(64,900,993)	(21,612,618)	-	(2,473,765)	-	(259,669)
28 Investment Tax Credit Adj.	(1,703,368)	-	-	-	-	-
29 Misc Revenue & Expense	(1,733,836)	(99,173)	-	102,338	-	-
30						
31 Total Operating Expenses:	4,320,802,712	1,127,230,117	(13,890,752)	3,290,802	57,834,436	69,376,249
32						
33 Operating Rev For Return:	1,201,107,755	307,494,169	(42,609,240)	(1,524,183)	(17,271,281)	(69,376,249)
34						
35 Rate Base:						
36 Electric Plant In Service	31,317,729,025	8,567,379,441	-	-	-	-
37 Plant Held for Future Use	23,896,248	9,657,872	-	-	-	-
38 Misc Deferred Debits	962,744,647	193,776,856	-	-	-	-
39 Elec Plant Acq Adj	14,875,820	1,753,028	-	-	-	-
40 Pensions	28,656,862	7,786,953	-	-	-	-
41 Prepayments	67,554,352	11,129,917	-	-	-	-
42 Fuel Stock	201,471,836	50,505,232	-	-	-	-
43 Material & Supplies	273,026,865	83,112,462	-	-	-	-
44 Working Capital	46,340,902	13,995,191	(131,295)	53,519	546,651	(126,926)
45 Weatherization Loans	199,224,237	-	-	-	-	-
46 Misc Rate Base	-	-	-	-	-	-
47						
48 Total Electric Plant:	33,135,520,794	8,939,096,950	(131,295)	53,519	546,651	(126,926)
49						
50 Rate Base Deductions:						
51 Accum Prov For Deprec	(9,626,761,743)	(2,815,387,372)	-	-	-	(752,230,479)
52 Accum Prov For Amort	(691,673,798)	(201,534,614)	-	-	-	(16,574,495)
53 Accum Def Income Tax	(2,565,819,019)	(623,521,952)	-	(9,430,521)	-	(602,563)
54 Unamortized ITC	(2,245,487)	(50,351)	-	-	-	-
55 Customer Adv For Const	(104,109,027)	(28,119,926)	-	-	-	-
56 Customer Service Deposits	-	-	-	-	-	-
57 Misc Rate Base Deductions	(2,269,895,491)	(489,871,272)	-	38,356,344	-	(7,266,788)
58						
59 Total Rate Base Deductions	(15,260,504,564)	(4,158,485,487)	-	28,925,824	-	(776,674,325)
60						
61 Total Rate Base:	17,875,016,231	4,780,611,463	(131,295)	28,979,343	546,651	(776,801,251)
62						
63 Return on Rate Base		6.432%	-0.891%	-0.065%	-0.360%	-0.735%
64						
65 Return on Equity		8.307%	-1.706%	-0.125%	-0.688%	-1.406%
66						
67 TAX CALCULATION:						
68 Operating Revenue		303,436,230	(56,499,992)	(2,218,974)	(22,905,864)	(86,698,974)
69 Other Deductions						
70 Interest (AFUDC)		(20,265,333)	-	-	-	-
71 Interest		96,206,794	(2,745)	606,921	11,431	(16,243,007)
72 Schedule "M" Additions		406,229,218	-	10,061,436	-	1,056,147
73 Schedule "M" Deductions		428,771,671	-	-	-	-
74 Income Before Tax		204,952,316	(56,497,246)	7,235,540	(22,917,295)	(69,399,819)
75						
76 State Income Taxes		9,304,835	(2,564,975)	328,494	(1,040,445)	(3,150,752)
77 Taxable Income		195,647,481	(53,932,271)	6,907,046	(21,876,850)	(66,249,067)
78						
79 Federal Income Taxes + Other		8,249,843	(11,325,777)	1,450,480	(4,594,138)	(13,912,304)
APPROXIMATE PRICE CHANGE		51,101,359	58,398,993	4,983,679	23,732,287	18,304,908

Pacificorp
Oregon General Rate Case
Adjustment Summary
Twelve Months Ending December 31, 2023

		Tab 7	Tab 8	OR Allocated
		Tax Adjustments	Rate Base Adjustments	Results of Operations December 2023
1	Operating Revenues:			
2	General Business Revenues	-	-	1,248,901,150
3	Interdepartmental	-	-	-
4	Special Sales	-	-	92,708,477
5	Other Operating Revenues	-	2,235,548	81,179,990
6	Total Operating Revenues	-	2,235,548	1,422,789,617
7				
8	Operating Expenses:			
9	Steam Production	-	(13,042,384)	238,036,042
10	Nuclear Production	-	-	-
11	Hydro Production	-	-	12,077,585
12	Other Power Supply	-	(297,478)	343,636,569
13	Transmission	-	-	60,587,175
14	Distribution	-	-	116,940,088
15	Customer Accounting	-	-	23,492,890
16	Customer Service & Info	-	-	6,029,376
17	Sales	-	-	-
18	Administrative & General	-	(980,746)	60,742,837
19				
20	Total O&M Expenses	-	(14,320,608)	861,542,561
21				
22	Depreciation	-	(3,093,033)	287,994,295
23	Amortization	-	2,373,437	43,237,301
24	Taxes Other Than Income	6,547,693	-	84,171,808
25	Income Taxes - Federal	(46,790,008)	5,625,758	(61,296,146)
26	Income Taxes - State	79,191	1,274,079	4,230,426
27	Income Taxes - Def Net	40,629,511	(3,623,440)	12,660,019
28	Investment Tax Credit Adj.	-	-	-
29	Misc Revenue & Expense	-	-	3,165
30				
31	Total Operating Expenses:	466,386	(11,763,808)	1,232,543,429
32				
33	Operating Rev For Return:	(466,386)	13,999,357	190,246,188
34				
35	Rate Base:			
36	Electric Plant In Service	-	285,403,652	8,852,783,093
37	Plant Held for Future Use	-	(9,657,872)	-
38	Misc Deferred Debits	-	(126,476,526)	67,300,330
39	Elec Plant Acq Adj	-	(1,051,423)	701,604
40	Pensions	-	(7,786,953)	-
41	Prepayments	-	-	11,129,917
42	Fuel Stock	-	(7,313,106)	43,192,126
43	Material & Supplies	-	(1,392,651)	81,719,811
44	Working Capital	(379,622)	(609,953)	13,347,565
45	Weatherization Loans	-	-	-
46	Misc Rate Base	-	-	-
47				
48	Total Electric Plant:	(379,622)	131,115,168	9,070,174,446
49				
50	Rate Base Deductions:			
51	Accum Prov For Deprec	-	(3,746,161)	(3,571,364,011)
52	Accum Prov For Amort	-	-	(218,109,109)
53	Accum Def Income Tax	(50,169,049)	40,243,899	(643,480,187)
54	Unamortized ITC	4,573	-	(45,778)
55	Customer Adv For Const	-	5,089,393	(23,030,533)
56	Customer Service Deposits	-	-	-
57	Misc Rate Base Deductions	27,572,240	16,186,182	(415,023,294)
58				
59	Total Rate Base Deductions	(22,592,236)	57,773,313	(4,871,052,912)
60				
61	Total Rate Base:	(22,971,858)	188,888,481	4,199,121,534
62				
63	Return on Rate Base	0.013%	0.136%	4.531%
64				
65	Return on Equity	0.026%	0.260%	4.668%
66				
67	TAX CALCULATION:			
68	Operating Revenue	(6,547,693)	17,275,753	145,840,487
69	Other Deductions			
70	Interest (AFUDC)	(1,090,745)	-	(21,356,078)
71	Interest	(480,344)	3,949,681	84,048,729
72	Schedule "M" Additions	(93,710,028)	9,745,647	333,382,419
73	Schedule "M" Deductions	28,327,582	(4,991,685)	452,107,568
74	Income Before Tax	(127,014,213)	28,063,404	(35,577,313)
75				
76	State Income Taxes	79,191	1,274,079	4,230,426
77	Taxable Income	(127,093,404)	26,789,326	(39,807,739)
78				
79	Federal Income Taxes + Other	(46,790,008)	5,625,758	(61,296,146)
	APPROXIMATE PRICE CHANGE	(1,631,974)	(515,983)	154,373,268

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:	2/18/2022
TIME:	4:19:42 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%	4.38%	2.09%
PREFERRED	0.01%	6.75%	0.00%
COMMON	52.25%	9.80%	5.12%
	100.00%		7.21%

OTHER INFORMATION

For information and support regarding capital structure and cost of debt, see testimony of Ms. Nikki L. Kobliha.
For information and support regarding return on common equity, see testimony of Ms. Ann E. Bulkley.

2020 PROTOCOL
Year End

RESULTS OF OPERATIONS SUMMARY

			JUNE 2021 UNADJUSTED RESULTS		DECEMBER 2023 NORMALIZED RESULTS	
	Description of Account Summary:	**Ref**	**TOTAL**	**OREGON**	**TOTAL**	**OREGON**
1	Operating Revenues					
2	General Business Revenues	2.2	5,081,632,249	1,308,339,123	5,022,194,276	1,248,901,150
3	Interdepartmental	2.2	0	0	0	0
4	Special Sales	2.2	212,315,668	52,145,322	368,049,381	92,708,477
5	Other Operating Revenues	2.3	227,962,549	74,239,841	248,243,892	81,179,990
6	Total Operating Revenues	2.3	5,521,910,467	1,434,724,286	5,638,487,549	1,422,789,617
7						
8	Operating Expenses:					
9	Steam Production	2.5	997,145,306	256,305,884	924,349,714	238,036,042
10	Nuclear Production	2.5	0	0	0	0
11	Hydro Production	2.6	76,270,911	19,884,087	46,326,914	12,077,585
12	Other Power Supply	2.7, .8	1,076,832,156	266,678,359	1,362,512,151	343,636,569
13	Transmission	2.9	220,828,048	57,410,559	232,875,087	60,587,175
14	Distribution	2.10	227,788,851	88,583,363	265,354,371	116,940,088
15	Customer Accounting	2.11	70,180,739	22,022,443	75,200,784	23,492,890
16	Customer Service & Infor	2.12	116,029,408	5,610,498	126,454,909	6,029,376
17	Sales	2.12	0	0	0	0
18	Administrative & General	2.13	296,924,361	86,907,150	193,298,120	60,742,837
19						
20	Total O & M Expenses	2.13	3,081,999,779	803,402,344	3,226,372,050	861,542,561
21						
22	Depreciation	2.14	1,035,081,277	232,580,644	1,271,626,317	287,994,295
23	Amortization	2.15	61,823,778	16,306,178	90,272,115	43,237,301
24	Taxes Other Than Income	2.15	212,196,714	79,098,063	234,822,593	84,171,808
25	Income Taxes - Federal	2.18	(28,741,917)	8,249,843	(165,208,190)	(61,296,146)
26	Income Taxes - State	2.18	26,781,277	9,304,835	30,934,209	4,230,426
27	Income Taxes - Def Net	2.16	(64,900,993)	(21,612,618)	(53,680,948)	12,660,019
28	Investment Tax Credit Adj.	2.15	(1,703,368)	0	(1,055,733)	0
29	Misc Revenue & Expense	2.3	(1,733,836)	(99,173)	(1,503,560)	3,165
30						
31	Total Operating Expenses	2.18	4,320,802,712	1,127,230,117	4,632,578,853	1,232,543,429
32						
33	Operating Revenue for Return		1,201,107,755	307,494,169	1,005,908,696	190,246,188
34						
35	Rate Base:					
36	Electric Plant in Service	2.26	31,317,729,025	8,567,379,441	32,579,238,234	8,852,783,093
37	Plant Held for Future Use	2.26	23,896,248	9,657,872	0	0
38	Misc Deferred Debits	2.28	962,744,647	193,776,856	459,239,830	67,300,330
39	Elec Plant Acq Adj	2.26,.27	14,875,820	1,753,028	10,842,796	701,604
40	Pensions	2.27	28,656,862	7,786,953	0	0
41	Prepayments	2.28	67,554,352	11,129,917	67,554,352	11,129,917
42	Fuel Stock	2.27	201,471,836	50,505,232	172,298,918	43,192,126
43	Material & Supplies	2.28	273,026,865	83,112,462	267,684,968	81,719,811
44	Working Capital	2.28	46,340,902	13,995,191	43,506,974	13,347,565
45	Weatherization Loans	2.27	199,224,237	0	199,224,237	0
46	Miscellaneous Rate Base	2.29	0	0	0	0
47						
48	Total Electric Plant		33,135,520,794	8,939,096,950	33,799,590,309	9,070,174,446
49						
50	Rate Base Deductions:					
51	Accum Prov For Depr	2.32	(9,626,761,743)	(2,815,387,372)	(12,050,132,685)	(3,571,364,011)
52	Accum Prov For Amort	2.33	(691,673,798)	(201,534,614)	(749,438,517)	(218,109,109)
53	Accum Def Income Taxes	2.30	(2,565,819,019)	(623,521,952)	(2,702,858,647)	(643,480,187)
54	Unamortized ITC	2.30	(2,245,487)	(50,351)	(2,339,440)	(45,778)
55	Customer Adv for Const	2.29	(104,109,027)	(28,119,926)	(104,109,027)	(23,030,533)
56	Customer Service Deposits	2.29	0	0	0	0
57	Misc. Rate Base Deductions	2.29	(2,269,895,491)	(489,871,272)	(2,038,041,418)	(415,023,294)
58						
59	Total Rate Base Deductions		(15,260,504,564)	(4,158,485,487)	(17,646,919,733)	(4,871,052,912)
60						
61	Total Rate Base		17,875,016,231	4,780,611,463	16,152,670,576	4,199,121,534
62						
63	Return on Rate Base		6.771%	6.432%	6.228%	4.531%
64						
65	Return on Equity		8.508%	8.307%	7.915%	4.668%
66	Net Power Costs			406,077,514	1,683,499,703	428,699,211
67	100 Basis Points in Equity:			24,978,695	84,397,704	21,940,410
68	Revenue Requirement Impact			33,122,356	111,913,405	29,093,517
69	Rate Base Decrease			(359,167,463)	(1,250,335,049)	(434,195,416)

	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
70	Sales to Ultimate Customers								
71	440	Residential Sales							
72			0	S		2,032,842,216	658,842,617	1,987,520,836	613,521,236
73									
74					B1	2,032,842,216	658,842,617	1,987,520,836	613,521,236
75									
76	442	Commercial & Industrial Sales							
77			0	S		3,031,724,688	643,689,980	3,019,120,003	631,085,295
78			P	SE		-	-	-	-
79			PT	SG		-	-	-	-
80									
81									
82					B1	3,031,724,688	643,689,980	3,019,120,003	631,085,295
83									
84	444	Public Street & Highway Lighting							
85			0	S		17,065,345	5,806,526	15,553,437	4,294,618
86			0	SO		-	-	-	-
87					B1	17,065,345	5,806,526	15,553,437	4,294,618
88									
89	445	Other Sales to Public Authority							
90			0	S		-	-	-	-
91									
92					B1	-	-	-	-
93									
94	448	Interdepartmental							
95			DPW	S		-	-	-	-
96			GP	SO		-	-	-	-
97					B1	-	-	-	-
98									
99	**Total Sales to Ultimate Customers**				**B1**	**5,081,632,249**	**1,308,339,123**	**5,022,194,276**	**1,248,901,150**
100									
101									
102									
103	447	Sales for Resale-Non NPC							
104			P	S		12,440,401	-	12,440,401	-
105					B1	12,440,401	-	12,440,401	-
106									
107	447NPC	Sales for Resale-NPC							
108			P	SG		203,582,710	53,074,709	355,608,980	92,708,477
109			P	SE		(3,707,443)	(929,387)	-	-
110			P	SG		-	-	-	-
111					B1	199,875,267	52,145,322	355,608,980	92,708,477
112									
113		Total Sales for Resale			B1	212,315,668	52,145,322	368,049,381	92,708,477
114									
115	449	Provision for Rate Refund							
116			P	S		-	-	-	-
117			P	SG		(3,239,918)	(844,658)	(3,239,918)	(844,658)
118									
119									
120					B1	(3,239,918)	(844,658)	(3,239,918)	(844,658)
121									
122	**Total Sales from Electricity**				**B1**	**5,290,707,999**	**1,359,639,787**	**5,387,003,739**	**1,340,764,969**
123	450	Forfeited Discounts & Interest							
124			CUST	S		6,599,968	(19,497)	6,599,968	(19,497)
125			CUST	SO		-	-	-	-
126					B1	6,599,968	(19,497)	6,599,968	(19,497)
127									
128	451	Misc Electric Revenue							
129			CUST	S		8,210,111	1,545,976	8,210,111	1,545,976
130			GP	SG		-	-	-	-
131			GP	SO		52,826	14,354	52,826	14,354
132					B1	8,262,937	1,560,331	8,262,937	1,560,331
133									
134	453	Water Sales							
135			P	SG		7,350	1,916	7,350	1,916
136					B1	7,350	1,916	7,350	1,916
137									
138	454	Rent of Electric Property							
139			DPW	S		10,236,067	4,606,685	10,236,067	4,606,685
140			T	SG		4,867,665	1,269,017	4,867,665	1,269,017
141			T	SG		-	-	-	-
142			GP	SO		3,142,114	853,809	3,142,114	853,809
143					B1	18,245,846	6,729,512	18,245,846	6,729,512

	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
144									
145									
146									
147	456	Other Electric Revenue							
148			DMSC	S		39,636,054	25,801,096	41,871,602	28,036,644
149			CUST	CN		-	-	-	-
150			OTHSE	SE		26,523,928	6,649,054	26,523,928	6,649,054
151			OTHSO	SO		(2,863,076)	(777,986)	(2,863,076)	(777,986)
152			OTHSGR	SG		134,789,460	35,140,073	152,835,254	39,844,674
153									
154									
155					B1	198,086,365	66,812,237	218,367,708	73,752,386
156									
157	**Total Other Electric Revenues**				**B1**	**231,202,467**	**75,084,499**	**251,483,810**	**82,024,648**
158									
159	**Total Electric Operating Revenues**				**B1**	**5,521,910,467**	**1,434,724,286**	**5,638,487,549**	**1,422,789,617**
160									
161	Summary of Revenues by Factor								
162		S				5,158,754,851	1,340,273,384	5,101,552,426	1,283,070,959
163		CN				-	-	-	-
164		SE				22,816,485	5,719,667	26,523,928	6,649,054
165		SO				331,864	90,178	331,864	90,178
166		SG				340,007,267	88,641,057	510,079,331	132,979,426
167		DGP				-	-	-	-
168									
169	Total Electric Operating Revenues					5,521,910,467	1,434,724,286	5,638,487,549	1,422,789,617
170	Miscellaneous Revenues								
171	41160	Gain on Sale of Utility Plant - CR							
172			DPW	S		-	-	-	-
173			T	SG		-	-	-	-
174			G	SO		-	-	-	-
175			T	SG		-	-	-	-
176			P	SG		-	-	-	-
177					B1	-	-	-	-
178									
179	41170	Loss on Sale of Utility Plant							
180			DPW	S		-	-	-	-
181			T	SG		-	-	-	-
182					B1	-	-	-	-
183									
184	4118	Gain from Emission Allowances							
185			P	S		-	-	-	-
186			P	SE		(47)	(12)	(47)	(12)
187					B1	(47)	(12)	(47)	(12)
188									
189	41181	Gain from Disposition of NOX Credits							
190			P	SE		-	-	-	-
191					B1	-	-	-	-
192									
193	4194	Impact Housing Interest Income							
194			P	SG		-	-	-	-
195					B1	-	-	-	-
196									
197	421	(Gain) / Loss on Sale of Utility Plant							
198			DPW	S		510,749	510,749	446,480	511,579
199			T	SG		-	-	-	-
200			T	SG		-	-	-	-
201			P	CN		-	-	-	-
202			PTD	SO		(2,244,538)	(609,910)	(2,950)	(801)
203			P	SG		-	-	(1,947,042)	(507,601)
204					B1	(1,733,789)	(99,161)	(1,503,512)	3,177
205									
206	**Total Miscellaneous Revenues**				**B1**	**(1,733,836)**	**(99,173)**	**(1,503,560)**	**3,165**
207	Miscellaneous Expenses								
208	4311	Interest on Customer Deposits							
209			CUST	S		-	-	-	-
210						-	-	-	-
211	**Total Miscellaneous Expenses**				B1	**-**	**-**	**-**	**-**
212									
213	**Net Misc Revenue and Expense**				**B1**	**(1,733,836)**	**(99,173)**	**(1,503,560)**	**3,165**
214									

	2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2021 UNADJUSTED RESULTS TOTAL	OREGON	DECEMBER 2023 NORMALIZED RESULTS TOTAL	OREGON
215	500	Operation Supervision & Engineering							
216			P	SG		13,865,751	3,614,849	14,632,305	3,814,692
217			P	SG		1,084,539	282,743	1,173,480	305,930
218			P	SG		-	-	(57)	(15)
219					B2	14,950,290	3,897,592	15,805,728	4,120,607
220									
221	501	Fuel Related-Non NPC							
222			P	S		6,207,125	4,921,418	6,716,162	5,325,016
223			P	SE		16,755,152	4,200,204	32,628,114	8,179,260
224			P	SE		-	-	-	-
225			P	SE		-	-	-	-
226			P	SE		264,509	66,307	286,201	71,745
227					B2	23,226,786	9,187,929	39,630,478	13,576,021
228									
229	501NPC	Fuel Related-NPC							
230			P	S		137,244	-	-	-
231			P	SE		637,368,410	159,776,374	582,045,698	145,908,002
232			P	SE		-	-	-	-
233			P	SE		-	-	-	-
234			P	SE		31,040,758	7,781,339	31,040,758	7,781,339
235					B2	668,546,412	167,557,713	613,086,456	153,689,341
236									
237		Total Fuel Related			B2	691,773,198	176,745,643	652,716,933	167,265,362
238									
239	502	Steam Expenses							
240			P	SG		75,504,557	19,684,296	81,175,898	21,162,834
241			P	SG		4,617,621	1,203,830	4,996,305	1,302,554
242			P	SG		-	-	1	0
243					B2	80,122,178	20,888,126	86,172,205	22,465,388
244									
245	503	Steam From Other Sources-Non-NPC							
246			P	SE		-	-	(2,433)	(610)
247					B2	-	-	(2,433)	(610)
248									
249	503NPC	Steam From Other Sources-NPC							
250			P	SE		5,119,912	1,283,466	4,484,106	1,124,082
251					B2	5,119,912	1,283,466	4,484,106	1,124,082
252									
253	505	Electric Expenses							
254			P	SG		1,041,685	271,571	1,125,294	293,368
255			P	SG		131,171	34,197	141,928	37,001
256			P	SG		-	-	-	-
257					B2	1,172,856	305,768	1,267,222	330,369
258									
259	506	Misc. Steam Expense							
260			P	SG		57,377,431	14,958,493	61,257,299	15,969,987
261			P	SG		-	-	(54,132,080)	(14,112,418)
262			P	SG		1,448,672	377,674	1,567,475	408,646
263					B2	58,826,103	15,336,166	8,692,695	2,266,215
264									
265	507	Rents							
266			P	SG		466,659	121,660	504,929	131,637
267			P	SG		-	-	-	-
268			P	SG		237	62	256	67
269					B2	466,896	121,721	505,186	131,704
270									
271	510	Maint Supervision & Engineering							
272			P	SG		5,990,074	1,561,633	6,340,605	1,653,017
273			P	SG		1,064,231	277,449	1,138,745	296,875
274			P	SG		-	-	608,863	158,733
275					B2	7,054,305	1,839,081	8,088,213	2,108,625
276									
277									
278									
279	511	Maintenance of Structures							
280			P	SG		22,011,978	5,738,598	23,429,619	6,108,182
281			P	SG		2,549,103	664,560	2,727,582	711,090
282			P	SG		-	-	-	-
283					B2	24,561,081	6,403,158	26,157,201	6,819,272
284									
285	512	Maintenance of Boiler Plant							
286			P	SG		67,917,271	17,706,265	72,317,868	18,853,516
287			P	SG		1,744,893	454,900	1,867,049	486,746
288			P	SG		-	-	-	-
289					B2	69,662,164	18,161,164	74,184,917	19,340,261
290									
291	513	Maintenance of Electric Plant							
292			P	SG		31,093,354	8,106,144	33,104,634	8,630,491
293			P	SG		300,806	78,421	321,867	83,912
294			P	SG		-	-	-	-
295					B2	31,394,160	8,184,565	33,426,501	8,714,403

Line	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
296									
297	514	Maintenance of Misc. Steam Plant							
298			P	SG		10,579,826	2,758,197	11,286,539	2,942,439
299			P	SG		1,462,336	381,236	1,564,724	407,929
300			P	SG		-	-	(23)	(6)
301					B2	12,042,162	3,139,433	12,851,240	3,350,362
302									
303	**Total Steam Power Generation**				**B2**	**997,145,306**	**256,305,884**	**924,349,714**	**238,036,042**
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		-	-	(2,433)	(634)
356			P	SG		-	-	-	-
357			P	SG		9,461,569	2,466,663	10,147,945	2,645,604
358			P	SG		1,637,780	426,975	1,659,006	432,509
359									
360					B2	11,099,349	2,893,638	11,804,461	3,077,463
361									
362	536	Water For Power							
363			P	SG		-	-	-	-
364			P	SG		294,395	76,750	319,680	83,342
365			P	SG		-	-	-	-
366									
367					B2	294,395	76,750	319,680	83,342
368									
369	537	Hydraulic Expenses							
370			P	SG		-	-	-	-
371			P	SG		4,157,768	1,083,944	4,531,686	1,181,426
372			P	SG		317,694	82,824	346,701	90,386
373									
374					B2	4,475,462	1,166,768	4,878,388	1,271,812

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	3,070,725	12,639,671	3,295,206
		P	SG		6,544,109	1,706,072	6,966,095	1,816,085
				B2	18,322,722	4,776,796	19,605,825	5,111,306
540	Rents (Hydro Generation)							
		P	SG		-	-	-	-
		P	SG		1,430,079	372,827	1,565,719	408,188
		P	SG		63,838	16,643	69,893	18,221
				B2	1,493,917	389,469	1,635,612	426,410
541	Maint Supervision & Engineering							
		P	SG		-	-	-	-
		P	SG		384	100	412	107
		P	SG		-	-	-	-
				B2	384	100	412	107
542	Maintenance of Structures							
		P	SG		-	-	-	-
		P	SG		742,250	193,507	790,556	206,101
		P	SG		72,934	19,014	77,412	20,182
				B2	815,184	212,521	867,968	226,282
543	Maintenance of Dams & Waterways							
		P	SG		-	-	-	-
		P	SG		693,668	180,842	738,577	192,549
		P	SG		354,924	92,530	378,242	98,609
				B2	1,048,592	273,371	1,116,819	291,159
544	Maintenance of Electric Plant							
		P	SG		-	-	-	-
		P	SG		1,627,801	424,373	1,729,586	450,909
		P	SG		250,736	65,368	265,905	69,322
				B2	1,878,537	489,741	1,995,491	520,231
545	Maintenance of Misc. Hydro Plant							
		P	SG		-	-	-	-
		P	SG		-	-	-	-
		P	SG		33,000,000	8,603,213	-	-
		P	SG		3,005,661	783,586	3,207,950	836,324
		P	SG		836,709	218,133	894,308	233,149
				B2	36,842,370	9,604,932	4,102,258	1,069,473
Total Hydraulic Power Generation				**B2**	**76,270,911**	**19,884,087**	**46,326,914**	**12,077,585**
546	Operation Super & Engineering							
		P	SG		320,354	83,517	348,117	90,755
		P	SG		-	-	-	-
		P	SG		-	-	(13)	(3)
				B2	320,354	83,517	348,104	90,752
547	Fuel-Non-NPC							
		P	SE		-	-	-	-
		P	SE		-	-	-	-
				B2	-	-	-	-
547NPC	Fuel-NPC							
		P	SE		289,072,443	72,465,071	308,846,992	77,422,181
		P	SE		1,980,087	496,371	1,980,087	496,371
				B2	291,052,531	72,961,442	310,827,079	77,918,552

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	4,601,237	19,009,367	4,955,807
		P	SG		383,214	99,905	413,062	107,687
		P	SG		-	-	(302)	(79)
				B2	18,032,530	4,701,142	19,422,127	5,063,415
549	Miscellaneous Other							
		P	S		32,386	32,386	34,592	34,592
		P	SG		4,035,159	1,051,980	4,255,949	1,109,540
		P	SG		4,490,304	1,170,638	4,871,468	1,270,008
		P	SG		-	-	(33,430)	(8,715)
		P	SG		-	-	-	-
				B2	8,557,850	2,255,004	9,128,579	2,405,425
550	Rents							
		P	S		377,689	377,689	410,642	410,642
		P	SG		-	-	-	-
		P	SG		40,789	10,634	44,347	11,561
		P	SG		7,423,249	1,935,266	8,070,924	2,104,117
				B2	7,841,726	2,323,589	8,525,913	2,526,321
551	Maint Supervision & Engineering							
		P	SG		-	-	-	-
				B2	-	-	-	-
552	Maintenance of Structures							
		P	SG		2,300,976	599,872	2,446,430	637,793
		P	SG		52,439	13,671	55,565	14,486
		P	SG		-	-	-	-
				B2	2,353,416	613,543	2,501,995	652,279
553	Maint of Generation & Electric Plant							
		P	SG		3,849,587	1,003,600	4,096,006	1,067,843
		P	SG		11,075,955	2,887,539	11,843,830	3,087,727
		P	SG		235,783	61,469	250,925	65,417
		P	SG		-	-	2,193,945	571,969
				B2	15,161,325	3,952,609	18,384,706	4,792,956
554	Maintenance of Misc. Other							
		P	SG		2,049,813	534,393	2,192,690	571,642
		P	SG		1,006,710	262,453	1,077,054	280,792
		P	SG		75,591	19,707	80,287	20,931
		P	SG		-	-	-	-
				B2	3,132,114	816,553	3,350,031	873,365
Total Other Power Generation				**B2**	**346,451,846**	**87,707,400**	**372,488,535**	**94,323,065**
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	-	(430,221)	(430,221)
		P	SE		62,781,784	15,738,222	44,724,911	11,211,701
	Seasonal Cont	P	SG		621,018,560	161,901,663	905,599,544	236,092,898
		P	DGP		-	-	-	-
					694,078,107	177,639,885	949,894,234	246,874,378
	Total Purchased Power			B2	698,068,616	177,639,885	953,884,743	246,874,378
556	System Control & Load Dispatch							
		P	SG		596,144	155,417	639,604	166,747
				B2	596,144	155,417	639,604	166,747
557	Other Expenses							
		P	S		6,878,698	3,050,781	7,476,612	3,316,961
		P	SG		34,992,756	9,122,731	38,177,818	9,953,088
		P	SGCT		-	-	-	-
		P	SE		8,552	2,144	9,298	2,331
		P	SG		-	-	-	-
		P	TROJP		-	-	-	-
				B2	41,880,006	12,175,656	45,663,727	13,272,379

	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**	**178,970,959**	**990,023,617**	**249,313,504**
556									
557	**Total Production Expense**				**B2**	**2,150,248,373**	**542,868,330**	**2,333,188,779**	**593,750,196**
558									
559									
560	Summary of Production Expense by Factor								
561		S				17,736,957	(2,617,726)	8,033,839	(2,343,010)
562		SG				1,088,119,808	283,676,556	1,319,111,207	343,896,803
563		SE				1,044,391,607	261,809,499	1,006,043,734	252,196,403
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	542,868,330	2,333,188,779	593,750,196
580	560	Operation Supervision & Engineering							
581			T	SG		8,985,016	2,342,424	9,473,335	2,469,731
582			T	SG		-	-	(934)	(243)
583									
584					B2	8,985,016	2,342,424	9,472,401	2,469,487
585									
586	561	Load Dispatching							
587			T	SG		17,775,685	4,634,182	18,688,869	4,872,252
588			T	SG		-	-	(149)	(39)
589									
590					B2	17,775,685	4,634,182	18,688,721	4,872,213
591	562	Station Expense							
592			T	SG		3,230,138	842,108	3,394,366	884,923
593			T	SG		-	-	-	-
594									
595					B2	3,230,138	842,108	3,394,366	884,923
596									
597	563	Overhead Line Expense							
598			T	SG		961,278	250,608	1,010,072	263,329
599			T	SG		-	-	-	-
600									
601					B2	961,278	250,608	1,010,072	263,329
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	34,776,545	148,428,446	38,695,804
615			T	SE		15,971,607	4,003,784	12,388,361	3,105,531
616						149,366,653	38,780,329	160,816,807	41,801,335
617									
618		Total Transmission of Electricity by Others			B2	149,366,653	38,780,329	160,816,807	41,801,335

2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2021 UNADJUSTED RESULTS TOTAL	OREGON	DECEMBER 2023 NORMALIZED RESULTS TOTAL	OREGON
566	Misc. Transmission Expense							
		T	SG		3,609,107	940,907	3,776,647	984,585
		T	SG		-	-	(4,743,194)	(1,236,567)
				B2	3,609,107	940,907	(966,547)	(251,982)
567	Rents - Transmission							
		T	SG		2,481,704	646,989	2,597,335	677,134
		T	SG		-	-	-	-
				B2	2,481,704	646,989	2,597,335	677,134
568	Maint Supervision & Engineering							
		T	SG		845,051	220,308	890,277	232,098
		T	SG		-	-	-	-
				B2	845,051	220,308	890,277	232,098
569	Maintenance of Structures							
		T	SG		5,239,955	1,366,074	5,598,731	1,459,608
		T	SG		-	-	-	-
				B2	5,239,955	1,366,074	5,598,731	1,459,608
570	Maintenance of Station Equipment							
		T	SG		10,323,490	2,691,369	11,004,857	2,869,004
		T	SG		-	-	(0)	(0)
				B2	10,323,490	2,691,369	11,004,857	2,869,004
571	Maintenance of Overhead Lines							
		T	SG		17,662,920	4,604,784	19,036,251	4,962,816
		T	SG		-	-	957,228	249,552
				B2	17,662,920	4,604,784	19,993,479	5,212,368
572	Maintenance of Underground Lines							
		T	SG		169,970	44,312	182,705	47,632
		T	SG		-	-	-	-
				B2	169,970	44,312	182,705	47,632
573	Maint of Misc. Transmission Plant							
		T	SG		177,081	46,166	191,882	50,024
		T	SG		-	-	-	-
				B2	177,081	46,166	191,882	50,024
Total Transmission Expense				**B2**	**220,828,048**	**57,410,559**	**232,875,087**	**60,587,175**
Summary of Transmission Expense by Factor								
		SE			15,971,607	4,003,784	12,388,361	3,105,531
		SG			204,856,441	53,406,775	220,486,725	57,481,643
		SNPT			-	-	-	-
Total Transmission Expense by Factor					220,828,048	57,410,559	232,875,087	60,587,175
580	Operation Supervision & Engineering							
		DPW	S		1,694,447	430,541	1,801,731	453,473
		DPW	SNPD		8,121,601	2,149,999	8,573,477	2,269,622
				B2	9,816,048	2,580,540	10,375,209	2,723,095
581	Load Dispatching							
		DPW	S		-	-	-	-
		DPW	SNPD		12,715,437	3,366,106	13,409,240	3,549,774
				B2	12,715,437	3,366,106	13,409,240	3,549,774
582	Station Expense							
		DPW	S		4,235,076	1,104,470	4,518,626	1,181,026
		DPW	SNPD		17,180	4,548	18,451	4,884
				B2	4,252,256	1,109,018	4,537,077	1,185,910
583	Overhead Line Expenses							
		DPW	S		9,361,055	1,780,369	9,917,899	1,887,265
		DPW	SNPD		166	44	175	46
				B2	9,361,221	1,780,413	9,918,075	1,887,312
584	Underground Line Expense							
		DPW	S		417	417	448	448
		DPW	SNPD		-	-	-	-
				B2	417	417	448	448
585	Street Lighting & Signal Systems							
		DPW	S		-	-	-	-
		DPW	SNPD		323,751	85,705	342,813	90,751
				B2	323,751	85,705	342,813	90,751

2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2021 UNADJUSTED RESULTS TOTAL	OREGON	DECEMBER 2023 NORMALIZED RESULTS TOTAL	OREGON
586	Meter Expenses							
		DPW	S		2,750,524	1,272,828	2,912,130	1,347,604
		DPW	SNPD		-	-	-	-
				B2	2,750,524	1,272,828	2,912,130	1,347,604
587	Customer Installation Expenses							
		DPW	S		16,553,911	6,350,268	17,539,599	6,725,086
		DPW	SNPD		-	-	-	-
				B2	16,553,911	6,350,268	17,539,599	6,725,086
588	Misc. Distribution Expenses							
		DPW	S		415,049	(115,145)	444,092	(122,388)
		DPW	SNPD		662,605	175,409	660,689	174,902
				B2	1,077,654	60,263	1,104,782	52,513
589	Rents							
		DPW	S		3,526,824	1,872,042	3,779,738	2,010,384
		DPW	SNPD		25,331	6,706	27,235	7,210
				B2	3,552,155	1,878,748	3,806,973	2,017,594
590	Maint Supervision & Engineering							
		DPW	S		2,797,810	822,012	2,961,133	870,564
		DPW	SNPD		2,560,779	677,905	2,692,533	712,784
				B2	5,358,589	1,499,917	5,653,666	1,583,348
591	Maintenance of Structures							
		DPW	S		1,756,099	500,380	1,902,591	542,121
		DPW	SNPD		59,698	15,804	64,666	17,119
				B2	1,815,797	516,184	1,967,257	559,240
592	Maintenance of Station Equipment							
		DPW	S		7,199,867	2,722,618	7,650,339	2,892,483
		DPW	SNPD		1,565,281	414,371	1,655,910	438,362
				B2	8,765,148	3,136,989	9,306,249	3,330,846
593	Maintenance of Overhead Lines							
		DPW	S		110,312,452	55,025,939	139,570,845	81,068,804
		DPW	SNPD		2,450,344	648,670	3,391,945	897,936
				B2	112,762,796	55,674,609	142,962,791	81,966,740
594	Maintenance of Underground Lines							
		DPW	S		28,989,233	7,107,330	31,042,303	7,588,671
		DPW	SNPD		23,258	6,157	24,670	6,531
				B2	29,012,491	7,113,487	31,066,974	7,595,202
595	Maintenance of Line Transformers							
		DPW	S		-	-	-	-
		DPW	SNPD		1,101,111	291,493	1,165,061	308,422
				B2	1,101,111	291,493	1,165,061	308,422
596	Maint of Street Lighting & Signal Sys.							
		DPW	S		1,868,303	689,285	1,995,782	734,147
		DPW	SNPD		-	-	-	-
				B2	1,868,303	689,285	1,995,782	734,147
597	Maintenance of Meters							
		DPW	S		691,372	214,424	733,787	227,348
		DPW	SNPD		26,553	7,029	30,778	8,148
				B2	717,925	221,454	764,564	235,496
598	Maint of Misc. Distribution Plant							
		DPW	S		1,430,122	(249,709)	1,547,816	(271,211)
		DPW	SNPD		4,553,196	1,205,349	4,977,865	1,317,770
				B2	5,983,318	955,640	6,525,682	1,046,559
Total Distribution Expense				**B2**	**227,788,851**	**88,583,363**	**265,354,371**	**116,940,088**
Summary of Distribution Expense by Factor								
	S				193,582,559	79,528,070	228,318,861	107,135,826
	SNPD				34,206,291	9,055,294	37,035,510	9,804,261
Total Distribution Expense by Factor					227,788,851	88,583,363	265,354,371	116,940,088
901	Supervision							
		CUST	S		615	-	678	-
		CUST	CN		2,256,716	699,355	2,406,098	745,648
				B2	2,257,332	699,355	2,406,776	745,648

	2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2021 UNADJUSTED RESULTS TOTAL	 OREGON	DECEMBER 2023 NORMALIZED RESULTS TOTAL	 OREGON
782									
783	902	Meter Reading Expense							
784			CUST	S		12,882,743	2,311,692	13,743,678	2,480,518
785			CUST	CN		388,569	120,417	413,818	128,242
786					B2	13,271,313	2,432,109	14,157,496	2,608,760
787									
788	903	Customer Receipts & Collections							
789			CUST	S		3,369,238	765,765	3,600,953	813,440
790			CUST	CN		39,229,538	12,157,206	42,034,981	13,026,611
791					B2	42,598,776	12,922,971	45,635,934	13,840,051
792									
793	904	Uncollectible Accounts							
794			CUST	S		11,886,522	5,916,318	12,816,874	6,241,502
795			P	SG		-	-	-	-
796			CUST	CN		141,303	43,790	155,627	48,229
797					B2	12,027,825	5,960,108	12,972,501	6,289,730
798									
799	905	Misc. Customer Accounts Expense							
800			CUST	S		-	-	-	-
801			CUST	CN		25,493	7,900	28,077	8,701
802					B2	25,493	7,900	28,077	8,701
803									
804	**Total Customer Accounts Expense**				**B2**	**70,180,739**	**22,022,443**	**75,200,784**	**23,492,890**
805									
806	Summary of Customer Accts Exp by Factor								
807			S			28,139,119	8,993,775	30,162,183	9,535,460
808			CN			42,041,620	13,028,668	45,038,601	13,957,430
809			SG			-	-	-	-
810	Total Customer Accounts Expense by Factor					70,180,739	22,022,443	75,200,784	23,492,890
811									
812	907	Supervision							
813			CUST	S		-	-	-	-
814			CUST	CN		2,906	900	3,067	950
815					B2	2,906	900	3,067	950
816									
817	908	Customer Assistance							
818			CUST	S		109,367,868	3,471,925	119,297,876	3,710,056
819			CUST	CN		2,019,273	625,771	2,133,435	661,150
820									
821									
822					B2	111,387,142	4,097,696	121,431,311	4,371,206
823									
824	909	Informational & Instructional Adv							
825			CUST	S		1,954,258	679,790	2,231,821	793,001
826			CUST	CN		2,683,338	831,564	2,786,780	863,621
827					B2	4,637,595	1,511,354	5,018,601	1,656,622
828									
829	910	Misc. Customer Service							
830			CUST	S		-	-	-	-
831			CUST	CN		1,766	547	1,930	598
832									
833					B2	1,766	547	1,930	598
834									
835	**Total Customer Service Expense**				**B2**	**116,029,408**	**5,610,498**	**126,454,909**	**6,029,376**
836									
837									
838	Summary of Customer Service Exp by Factor								
839			S			111,322,126	4,151,715	121,529,697	4,503,056
840			CN			4,707,282	1,458,783	4,925,211	1,526,319
841									
842	Total Customer Service Expense by Factor				B2	116,029,408	5,610,498	126,454,909	6,029,376
843									
844									
845	911	Supervision							
846			CUST	S		-	-	-	-
847			CUST	CN		-	-	-	-
848					B2	-	-	-	-
849									
850	912	Demonstration & Selling Expense							
851			CUST	S		-	-	-	-
852			CUST	CN		-	-	-	-
853					B2	-	-	-	-
854									
855	913	Advertising Expense							
856			CUST	S		-	-	-	-
857			CUST	CN		-	-	-	-
858					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**	**126,454,909**	**6,029,376**
920	Administrative & General Salaries							
		PTD	S		2,285,428	702,610	2,405,442	739,506
		CUST	CN		-	-	-	-
		PTD	SO		76,467,813	20,778,661	80,666,662	21,919,618
				B2	78,753,241	21,481,271	83,072,105	22,659,124
921	Office Supplies & expenses							
		PTD	S		2,345,814	1,810,997	2,518,313	1,944,169
		CUST	CN		87,451	27,101	93,881	29,094
		PTD	SO		8,230,193	2,236,397	10,141,692	2,755,810
				B2	10,663,458	4,074,495	12,753,887	4,729,073
922	A&G Expenses Transferred							
		PTD	S		-	-	-	-
		CUST	CN		-	-	-	-
		PTD	SO		(37,446,530)	(10,175,376)	(39,576,424)	(10,754,134)
				B2	(37,446,530)	(10,175,376)	(39,576,424)	(10,754,134)
923	Outside Services							
		PTD	S		1,045,345	229,797	1,091,542	239,952
		CUST	CN		-	-	-	-
		PTD	SO		22,722,700	6,174,458	23,726,885	6,447,326
				B2	23,768,045	6,404,255	24,818,427	6,687,278
924	Property Insurance							
		PT	S		11,665,617	7,448,035	16,064,875	11,847,293
		PT	SG		-	-	-	-
		PTD	SO		4,371,510	1,187,874	3,612,548	981,641
				B2	16,037,127	8,635,909	19,677,423	12,828,933
925	Injuries & Damages							
		PTD	S		1,484,743	1,484,743	1,608,709	1,608,709
		PTD	SO		151,600,598	41,194,555	33,047,771	8,980,098
				B2	153,085,341	42,679,298	34,656,480	10,588,807
926	Employee Pensions & Benefits							
		LABOR	S		5,664,605	163,978	6,023,258	174,360
		CUST	CN		-	-	-	-
		LABOR	SO		114,566,722	31,131,309	119,538,210	32,482,216
				B2	120,231,327	31,295,287	125,561,468	32,656,576
927	Franchise Requirements							
		DMSC	S		-	-	-	-
		DMSC	SO		-	-	-	-
				B2	-	-	-	-
928	Regulatory Commission Expense							
		DMSC	S		18,139,814	5,799,002	19,310,225	6,019,755
		P	SE		-	-	-	-
		DMSC	SO		2,239,683	608,591	2,409,984	654,867
		FERC	SG		4,289,878	1,118,386	4,628,933	1,206,779
				B2	24,669,376	7,525,979	26,349,142	7,881,401
929	Duplicate Charges							
		LABOR	S		-	-	-	-
		LABOR	SO		(124,736,799)	(33,894,833)	(125,385,193)	(34,071,021)
				B2	(124,736,799)	(33,894,833)	(125,385,193)	(34,071,021)
930	Misc General Expenses							
		PTD	S		21,320	130	(1,647,450)	(1,669,716)
		CUST	CN		-	-	-	-
		P	SG		-	-	-	-
		LABOR	SO		2,246,757	610,513	1,796,472	488,157
				B2	2,268,077	610,643	149,022	(1,181,559)

	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
938									
939	931	Rents							
940			PTD	S		1,032,000	454,841	1,113,828	490,906
941			PTD	SO		2,060,717	559,960	2,224,113	604,360
942					B2	3,092,716	1,014,801	3,337,941	1,095,266
943									
944	935	Maintenance of General Plant							
945			G	S		392,947	149,681	412,805	157,258
946			CUST	CN		27,697	8,583	29,091	9,015
947			G	SO		26,118,338	7,097,157	27,441,947	7,456,823
948					B2	26,538,982	7,255,422	27,883,842	7,623,096
949									
950	**Total Administrative & General Expense**				**B2**	**296,924,361**	**86,907,150**	**193,298,120**	**60,742,837**
951									
952	Summary of A&G Expense by Factor								
953		S				44,077,632	18,243,813	48,901,547	21,552,190
954		SE				-	-	-	-
955		SO				248,441,702	67,509,267	139,644,667	37,945,760
956		SG				4,289,878	1,118,386	4,628,933	1,206,779
957		CN				115,148	35,684	122,972	38,109
958	Total A&G Expense by Factor					296,924,361	86,907,150	193,298,120	60,742,837
959									
960	**Total O&M Expense**				**B2**	**3,081,999,779**	**803,402,344**	**3,226,372,050**	**861,542,561**
961	403SP	Steam Depreciation							
962			P	S		180,756,088	-	180,756,088	-
963			P	SG		40,420,413	10,537,740	40,420,413	10,537,740
964			P	SG		33,611,594	8,762,657	33,611,594	8,762,657
965			P	SG		223,954,796	58,385,781	364,113,614	94,925,664
966			P	SG		7,589,695	1,978,660	7,589,695	1,978,660
967					B3	486,332,585	79,664,838	626,491,403	116,204,721
968									
969	403NP	Nuclear Depreciation							
970			P	SG		-	-	-	-
971					B3	-	-	-	-
972									
973	403HP	Hydro Depreciation							
974			P	SG		(24,185,191)	(6,305,162)	(24,185,191)	(6,305,162)
975			P	SG		1,348,641	351,595	1,348,641	351,595
976			P	SG		46,696,890	12,174,039	48,954,211	12,762,530
977			P	SG		6,934,787	1,807,923	8,780,939	2,289,221
978			P	SG		-	-	-	-
979					B3	30,795,127	8,028,395	34,898,599	9,098,184
980									
981	403OP	Other Production Depreciation							
982			p	S		4,783	-	4,783	-
983			P	SG		-	-	-	-
984			P	SG		65,951,638	17,193,818	69,147,316	18,026,942
985			P	SG		3,697,797	964,028	3,697,797	964,028
986			P	SG		97,958,758	25,538,183	137,093,159	35,740,655
987					B3	167,612,977	43,696,029	209,943,056	54,731,626
988									
989	403TP	Transmission Depreciation							
990			T	SG		8,458,141	2,205,066	8,458,141	2,205,066
991			T	SG		10,613,292	2,766,921	10,613,292	2,766,921
992			T	SG		106,315,401	27,716,789	119,158,716	31,065,085
993					B3	125,386,834	32,688,776	138,230,148	36,037,072
994									
995									
996									
997	403	Distribution Depreciation							
998	360	Land & Land Rights	DPW	S		420,462	61,427	664,106	69,299
999	361	Structures	DPW	S		2,158,154	544,558	2,620,006	559,481
1000	362	Station Equipment	DPW	S		12,341,072	6,154,345	16,173,237	6,278,171
1001	363	Storage Battery Equip	DPW	S		-	-	-	-
1002	364	Poles & Towers	DPW	S		45,813,613	13,885,875	50,821,831	14,047,702
1003	365	OH Conductors	DPW	S		20,782,723	6,876,026	23,934,218	6,977,858
1004	366	UG Conduit	DPW	S		9,700,542	1,945,136	11,264,100	1,995,658
1005	367	UG Conductor	DPW	S		21,530,296	4,183,811	25,177,761	4,301,669
1006	368	Line Trans	DPW	S		35,711,989	11,543,624	41,233,042	11,722,022
1007	369	Services	DPW	S		20,733,655	6,967,771	24,147,742	7,078,088
1008	370	Meters	DPW	S		9,771,798	2,573,927	10,706,351	2,604,125
1009	371	Inst Cust Prem	DPW	S		478,452	121,725	510,764	122,769
1010	372	Leased Property	DPW	S		-	-	-	-
1011	373	Street Lighting	DPW	S		2,248,401	663,724	2,479,804	671,201
1012					B3	181,691,155	55,521,949	209,732,961	56,428,045

	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
1013									
1014	403GP	General Depreciation							
1015			G-SITUS	S		15,621,693	5,548,245	17,626,032	6,150,304
1016			G-DGP	SG		18,231	4,753	18,231	4,753
1017			G-DGU	SG		51,315	13,378	51,315	13,378
1018			P	SE		108,300	27,149	110,810	27,778
1019			CUST	CN		966,692	299,577	923,079	286,062
1020			G-SG	SG		10,111,049	2,635,985	10,622,788	2,769,397
1021			PTD	SO		16,310,325	4,432,018	22,902,899	6,223,423
1022			G-SG	SG		8,187	2,134	8,187	2,134
1023			G-SG	SG		66,807	17,417	66,807	17,417
1024					B3	43,262,598	12,980,656	52,330,149	15,494,647
1025									
1026	403GV0	General Vehicles							
1027			G-SG	SG		-	-	-	-
1028					B3	-	-	-	-
1029									
1030	403MP	Mining Depreciation							
1031			P	SE		-	-	-	-
1032					B3	-	-	-	-
1033									
1034	403EP	Experimental Plant Depreciation							
1035			P	SG		-	-	-	-
1036			P	SG		-	-	-	-
1037					B3	-	-	-	-
1038	4031	ARO Depreciation							
1039			P	S		-	-	-	-
1040					B3	-	-	-	-
1041									
1042									
1043	**Total Depreciation Expense**				**B3**	**1,035,081,277**	**232,580,644**	**1,271,626,317**	**287,994,295**
1044									
1045	Summary	S				197,317,632	61,070,195	227,363,777	62,578,349
1046		DGP				-	-	-	-
1047		DGU				-	-	-	-
1048		SG				639,622,241	166,751,706	839,569,664	218,878,683
1049		SO				16,310,325	4,432,018	22,902,899	6,223,423
1050		CN				966,692	299,577	923,079	286,062
1051		SE				108,300	27,149	110,810	27,778
1052		SSGCH				-	-	-	-
1053		SSGCT				-	-	-	-
1054	Total Depreciation Expense By Factor					854,325,189	232,580,644	1,090,870,229	287,994,295
1055									
1056	404GP	Amort of LT Plant - Leasehold Improvements							
1057			I-SITUS	S		440,350	293,726	472,342	322,905
1058			I-SG	SG		-	-	-	-
1059			PTD	SO		247,138	67,155	108,292	29,426
1060			I-DGU	SG		-	-	-	-
1061			CUST	CN		-	-	-	-
1062			I-DGP	SG		-	-	-	-
1063					B4	687,488	360,880	580,634	352,331
1064									
1065	404SP	Amort of LT Plant - Cap Lease Steam							
1066			P	SG		-	-	-	-
1067			P	SG		-	-	-	-
1068					B4	-	-	-	-
1069									
1070	404IP	Amort of LT Plant - Intangible Plant							
1071			I-SITUS	S		4,421,013	11,685	4,419,575	11,687
1072			P	SE		1,821	457	(12,865)	(3,225)
1073			I-SG	SG		16,038,025	4,181,168	7,035,127	1,834,082
1074			PTD	SO		14,405,872	3,914,519	29,348,751	7,974,960
1075			CUST	CN		13,528,148	4,192,364	13,792,251	4,274,209
1076			I-SG	SG		2,694,702	702,518	2,680,267	698,755
1077			I-SG	SG		293,112	76,415	314,346	81,951
1078			I-DGP	SG		78,646	20,503	78,646	20,503
1079			I-SG	SG		-	-	-	-
1080			I-SG	SG		13,762	3,588	13,762	3,588
1081			I-DGU	SG		14,143	3,687	14,143	3,687
1082					B4	51,489,245	13,106,904	57,684,004	14,900,197
1083									
1084	404MP	Amort of LT Plant - Mining Plant							
1085			P	SE		-	-	-	-
1086					B4	-	-	-	-
1087									
1088	404OP	Amort of LT Plant - Other Plant							
1089			P	SG		-	-	-	-
1090					B4	-	-	-	-
1091									
1092									

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
1093	404HP	Amortization of Other Electric Plant							
1094			P	SG		311,696	81,260	311,696	81,260
1095			P	SG		-	-	-	-
1096			P	SG		-	-	-	-
1097					B4	311,696	81,260	311,696	81,260
1098									
1099	**Total Amortization of Limited Term Plant**				**B4**	**52,488,428**	**13,549,044**	**58,576,334**	**15,333,788**
1100									
1101									
1102	405	Amortization of Other Electric Plant							
1103			GP	S		-	-	-	-
1104									
1105					B4	-	-	-	-
1106									
1107	406	Amortization of Plant Acquisition Adj							
1108			P	S		301,635	-	301,635	-
1109			P	SG		-	-	-	-
1110			P	SG		-	-	-	-
1111			P	SG		6,496,204	1,693,583	1,789,996	466,658
1112			P	SO		-	-	-	-
1113					B4	6,797,839	1,693,583	2,091,631	466,658
1114	407	Amort of Prop Losses, Unrec Plant, etc							
1115			DPW	S		2,513,687	1,057,340	28,642,494	27,186,148
1116			GP	SO		-	-	-	-
1117			P	SG-P		-	-	-	-
1118			P	SE		-	-	-	-
1119			P	SG		23,824	6,211	961,656	250,707
1120			P	TROJP		-	-	-	-
1121					B4	2,537,511	1,063,551	29,604,150	27,436,855
1122									
1123	**Total Amortization Expense**				**B4**	**61,823,778**	**16,306,178**	**90,272,115**	**43,237,301**
1124									
1125									
1126									
1127	Summary of Amortization Expense by Factor								
1128		S				7,676,686	1,362,750	33,836,047	27,520,739
1129		SE				1,821	457	(12,865)	(3,225)
1130		TROJP				-	-	-	-
1131		DGP				-	-	-	-
1132		DGU				-	-	-	-
1133		SO				14,653,009	3,981,674	29,457,043	8,004,386
1134		SSGCT				-	-	-	-
1135		SSGCH				-	-	-	-
1136		CN				13,528,148	4,192,364	13,792,251	4,274,209
1137		SG				25,964,114	6,768,933	13,199,639	3,441,191
1138	Total Amortization Expense by Factor					61,823,778	16,306,178	90,272,115	43,237,301
1139	408	Taxes Other Than Income							
1140			DMSC	S		33,900,676	30,692,497	32,426,729	29,218,549
1141			GP	GPS		161,965,403	44,010,992	185,977,000	50,535,683
1142			GP	SO		13,226,755	3,594,117	13,226,755	3,594,117
1143			P	SE		871,530	218,476	871,530	218,476
1144			P	SG		2,232,349	581,981	2,320,579	604,983
1145			DMSC	OPRV-ID		-	-	-	-
1146			GP	EXCTAX		-	-	-	-
1147			GP	SG		-	-	-	-
1148									
1149									
1150									
1151	**Total Taxes Other Than Income**				**B5**	**212,196,714**	**79,098,063**	**234,822,593**	**84,171,808**
1152									
1153									
1154	41140	Deferred Investment Tax Credit - Fed							
1155			PTD	DGU		(1,703,368)	-	(1,055,733)	-
1156									
1157					B7	(1,703,368)	-	(1,055,733)	-
1158									
1159	41141	Deferred Investment Tax Credit - Idaho							
1160			PTD	DGU		-	-	-	-
1161									
1162					B7	-	-	-	-
1163									
1164	**Total Deferred ITC**				**B7**	**(1,703,368)**	**-**	**(1,055,733)**	**-**
1165									
1166									
1167	427	Interest on Long-Term Debt							
1168			GP	S		373,768,734	99,963,159	337,754,280	87,804,135
1169			GP	SNP		-	-	-	-
1170					B6	373,768,734	99,963,159	337,754,280	87,804,135

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
428	Amortization of Debt Disc & Exp							
		GP	SNP		5,103,007	1,306,296	5,103,007	1,306,296
				B6	5,103,007	1,306,296	5,103,007	1,306,296
429	Amortization of Premium on Debt							
		GP	SNP		(11,026)	(2,822)	(11,026)	(2,822)
				B6	(11,026)	(2,822)	(11,026)	(2,822)
431	Other Interest Expense							
		NUTIL	OTH		-	-	-	-
		GP	SO		-	-	-	-
		GP	SNP		18,548,860	4,748,241	18,552,610	4,749,201
				B6	18,548,860	4,748,241	18,552,610	4,749,201
432	AFUDC - Borrowed							
		GP	SNP		(38,314,971)	(9,808,081)	(38,314,971)	(9,808,081)
					(38,314,971)	(9,808,081)	(38,314,971)	(9,808,081)
	Total Elec. Interest Deductions for Tax			B6	359,094,605	96,206,794	323,083,901	84,048,729
	Non-Regulated Portion of Interest							
	427	NUTIL	NUTIL		-	-	-	-
	428	NUTIL	NUTIL		-	-	-	-
	429	NUTIL	NUTIL		-	-	-	-
	431	NUTIL	NUTIL		-	-	-	-
	Total Non-Regulated Interest				-	-	-	-
	Total Interest Deductions for Tax			B6	359,094,605	96,206,794	323,083,901	84,048,729
419	Interest & Dividends							
		GP	S		-	-	-	-
		GP	SNP		(79,165,909)	(20,265,333)	(83,426,872)	(21,356,078)
	Total Operating Deductions for Tax			B6	(79,165,909)	(20,265,333)	(83,426,872)	(21,356,078)
41010	Deferred Income Tax - Federal-DR							
		GP	S		309,752	186,017	(5,195,564)	404,694
		P	TROJD		-	-	-	-
		PT	SG		510,498	133,089	510,498	133,089
		LABOR	SO		(19,941,046)	(5,418,597)	6,619,626	1,798,756
		GP	SNP		28,884,552	7,394,029	29,009,377	7,425,983
		P	SE		(281,840)	(70,652)	37,622	9,431
		PT	SG		37,571,837	9,795,106	34,184,336	8,911,973
		GP	GPS		49,230,998	13,377,579	12,039,020	3,271,373
		DITEXP	DITEXP		-	-	-	-
		CUST	BADDEBT		-	-	-	-
		CUST	CN		-	-	-	-
		IBT	IBT		-	-	-	-
		DPW	CIAC		-	-	-	-
		GP	SCHMDEXP		-	-	-	-
		TAXDEPR	TAXDEPR		301,248,033	79,558,685	337,481,784	89,127,908
		DPW	SNPD		238,377	63,105	-	-
				B7	397,771,161	105,018,361	414,686,699	111,083,207
41110	Deferred Income Tax - Federal-CR							
		GP	S		(181,173,017)	(60,241,301)	(131,453,332)	(20,437,298)
		P	SE		(9,598,996)	(2,406,289)	(4,161,684)	(1,043,257)
		PT	SG		(1,109,267)	(289,190)	(1,109,267)	(289,190)
		GP	SNP		(17,992,952)	(4,605,937)	(17,516,892)	(4,484,072)
		PT	SG		(680,477)	(177,403)	(579,991)	(151,206)
		GP	GPS		1,212,047	329,351	-	-
		LABOR	SO		(10,150,835)	(2,758,295)	(4,484,432)	(1,218,558)
		PT	SNPD		(937,677)	(248,227)	-	-
		CUST	BADDEBT		(873,780)	(423,653)	(0)	(0)
		P	SG		-	-	-	-
		DITEXP	SG		-	-	-	-
		P	TROJD		11,239	2,910	(1)	(0)
		IBT	CN		-	-	11,988	3,715
		DPW	CIAC		(29,968,119)	(7,933,339)	(21,049,481)	(5,572,344)
		GP	SCHMDEXP		(211,410,319)	(47,879,605)	(288,024,556)	(65,230,979)
		TAXDEPR	TAXDEPR		-	-	-	-
				B7	(462,672,154)	(126,630,979)	(468,367,647)	(98,423,188)
Total Deferred Income Taxes				**B7**	**(64,900,993)**	**(21,612,618)**	**(53,680,948)**	**12,660,019**

	2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2021 UNADJUSTED RESULTS TOTAL	 OREGON	DECEMBER 2023 NORMALIZED RESULTS TOTAL	 OREGON
1250	SCHMAF	Additions - Flow Through							
1251			SCHMAF	S		-	-	-	-
1252			SCHMAF	SNP		-	-	-	-
1253			SCHMAF	SO		-	-	-	-
1254			SCHMAF	SE		-	-	-	-
1255			SCHMAF	TROJP		-	-	-	-
1256			SCHMAF	SG		-	-	-	-
1257					B6	-	-	-	-
1258									
1259	SCHMAP	Additions - Permanent							
1260			P	S		-	-	-	-
1261			P	SE		55,517	13,917	44,959	11,270
1262			LABOR	SNP		-	-	-	-
1263			SCHMAP-SO	SO		3,374,502	916,956	2,924,000	794,541
1264			SCHMAP	SG		-	-	-	-
1265			DPW	SCHMDEXP		149,749	33,915	129,194	29,259
1266					B6	3,579,768	964,788	3,098,153	835,071
1267									
1268	SCHMAT	Additions - Temporary							
1269			SCHMAT-SITUS	S		117,375,678	136,399,832	(51,730,763)	15,340,473
1270			P	SG		-	-	-	-
1271			DPW	CIAC		121,888,015	32,266,923	85,613,628	22,664,151
1272			SCHMAT-SNP	SNP		73,181,946	18,733,524	71,245,689	18,237,871
1273			P	TROJD		(45,715)	(11,836)	0	0
1274			P	SG		-	-	-	-
1275			SCHMAT-SE	SE		39,041,566	9,786,993	16,926,649	4,243,195
1276			P	SG		2,832,821	738,526	6,940,770	1,809,483
1277			SCHMAT-GPS	GPS		(4,929,707)	(1,339,553)	-	-
1278			SCHMAT-SO	SO		41,286,045	11,218,691	18,239,327	4,956,187
1279			SCHMAT-SNP	SNPD		3,813,773	1,009,605	(0)	(0)
1280			CUST	BADDEBT		3,553,889	1,723,107	0	0
1281			P	CN		-	-	(48,760)	(15,111)
1282			BOOKDEPR	SCHMDEXP		859,859,922	194,738,619	1,171,469,649	265,311,099
1283					B6	1,257,858,233	405,264,430	1,318,656,189	332,547,348
1284									
1285	TOTAL SCHEDULE - M ADDITIONS				B6	1,261,438,001	406,229,218	1,321,754,341	333,382,419
1286									
1287	SCHMDF	Deductions - Flow Through							
1288			SCHMDF	S		-	-	-	-
1289			SCHMDF	DGP		-	-	-	-
1290			SCHMDF	DGU		-	-	-	-
1291					B6	-	-	-	-
1292	SCHMDP	Deductions - Permanent							
1293			SCHMDP	S		-	-	-	-
1294			P	SE		6,410,304	1,606,944	1,101,362	276,091
1295			PTD	SNP		109,994	28,157	107,935	27,630
1296			BOOKDEPR	SCHMDEXP		-	-	-	-
1297			P	SG		-	-	-	-
1298			SCHMDP-SO	SO		-	-	-	-
1299					B6	6,520,299	1,635,101	1,209,297	303,721
1300									
1301	SCHMDT	Deductions - Temporary							
1302			GP	S		1,259,837	756,574	(21,131,698)	1,645,989
1303			CUST	BADDEBT		-	-	-	-
1304			SCHMDT-SNP	SNP		117,480,879	30,073,414	117,988,573	30,203,376
1305			CUST	CN		-	-	-	-
1306			SCHMDT	SG		2,076,324	541,305	2,076,324	541,305
1307			CUST	DGP		-	-	-	-
1308			P	SE		(1,146,315)	(287,360)	153,018	38,359
1309			SCHMDT-SG	SG		152,814,284	39,839,206	139,036,448	36,247,278
1310			SCHMDT-GPS	GPS		200,235,075	54,410,041	48,965,774	13,305,510
1311			SCHMDT-SO	SO		(81,105,351)	(22,038,823)	26,923,700	7,315,999
1312			TAXDEPR	TAXDEPR		1,225,252,918	323,585,551	1,372,624,863	362,506,031
1313			DPW	SNPD		969,539	256,662	-	-
1314					B6	1,617,837,190	427,136,570	1,686,637,003	451,803,847
1315									
1316	TOTAL SCHEDULE - M DEDUCTIONS				B6	1,624,357,489	428,771,671	1,687,846,300	452,107,568
1317									
1318	**TOTAL SCHEDULE - M ADJUSTMENTS**				**B6**	**(362,919,488)**	**(22,542,453)**	**(366,091,959)**	**(118,725,149)**
1319									
1320									
1321									
1322	40911	State Income Taxes							
1323			IBT			22,232,133	9,304,835	9,586,167	(1,615,210)
1324			IBT	S		4,549,144	-	21,348,043	5,845,636
1325		PTC	P	SG		-	-	-	-
1326			IBT	IBT		-	-	-	-
1327	**Total State Tax Expense**					**26,781,277**	**9,304,835**	**30,934,209**	**4,230,426**
1328									
1329									

	2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2021 UNADJUSTED RESULTS TOTAL	 OREGON	DECEMBER 2023 NORMALIZED RESULTS TOTAL	 OREGON
1330	Calculation of Taxable Income:								
1331		Operating Revenues				5,521,910,467	1,434,724,286	5,638,487,549	1,422,789,617
1332		Operating Deductions:							
1333		O & M Expenses				3,081,999,779	803,402,344	3,226,372,050	861,542,561
1334		Depreciation Expense				1,035,081,277	232,580,644	1,271,626,317	287,994,295
1335		Amortization Expense				61,823,778	16,306,178	90,272,115	43,237,301
1336		Taxes Other Than Income				212,196,714	79,098,063	234,822,593	84,171,808
1337		Interest & Dividends (AFUDC-Equity)				(79,165,909)	(20,265,333)	(83,426,872)	(21,356,078)
1338		Misc Revenue & Expense				(1,733,836)	(99,173)	(1,503,560)	3,165
1339		Total Operating Deductions				4,310,201,804	1,111,022,723	4,738,162,643	1,255,593,052
1340		Other Deductions:							
1341		Interest Deductions				359,094,605	96,206,794	323,083,901	84,048,729
1342		Interest on PCRBS				-	-	-	-
1343		Schedule M Adjustments				(362,919,488)	(22,542,453)	(366,091,959)	(118,725,149)
1344									
1345		Income Before State Taxes				489,694,569	204,952,316	211,149,047	(35,577,313)
1346									
1347		State Income Taxes				26,781,277	9,304,835	30,934,209	4,230,426
1348									
1349	Total Taxable Income					462,913,292	195,647,481	180,214,838	(39,807,739)
1350									
1351	Tax Rate					21.0%	21.0%	21.0%	21.0%
1352									
1353	Federal Income Tax - Calculated					97,211,791	41,085,971	37,845,116	(8,359,625)
1354									
1355	Adjustments to Calculated Tax:								
1356	40910		P	SE		(45,220)	(11,336)	(17,000)	(4,262)
1357	40910	PTC	P	SG		(125,906,829)	(32,824,341)	(203,036,306)	(52,932,259)
1358	40910		P	SO		(1,659)	(451)	-	-
1359	40910	IRS Settle	LABOR	S		-	-	-	-
1360	**Federal Income Tax Expense**					**(28,741,917)**	**8,249,843**	**(165,208,190)**	**(61,296,146)**
1361									
1362	**Total Operating Expenses**					**4,320,802,712**	**1,127,230,117**	**4,632,578,853**	**1,232,543,429**
1363	310	Land and Land Rights							
1364			P	SG		2,327,033	606,665	2,327,033	606,665
1365			P	SG		33,837,468	8,821,544	33,837,468	8,821,544
1366			P	SG		54,188,889	14,127,229	54,188,889	14,127,229
1367			P	S		-	-	-	-
1368			P	SG		1,266,851	330,272	1,266,851	330,272
1369					B8	91,620,242	23,885,710	91,620,242	23,885,710
1370									
1371	311	Structures and Improvements							
1372			P	SG		226,302,042	58,997,716	226,302,042	58,997,716
1373			P	SG		313,179,657	81,647,008	313,179,657	81,647,008
1374			P	SG		458,329,586	119,488,091	458,329,586	119,488,091
1375			P	SG		-	-	-	-
1376					B8	997,811,285	260,132,815	997,811,285	260,132,815
1377									
1378	312	Boiler Plant Equipment							
1379			P	SG		586,722,706	152,960,616	586,722,706	152,960,616
1380			P	SG		464,967,271	121,218,558	464,967,271	121,218,558
1381			P	SG		3,285,513,183	856,544,524	3,347,065,168	872,591,337
1382			P	SG		-	-	-	-
1383					B8	4,337,203,161	1,130,723,698	4,398,755,145	1,146,770,511
1384									
1385	314	Turbogenerator Units							
1386			P	SG		109,027,524	28,423,848	109,027,524	28,423,848
1387			P	SG		109,153,256	28,456,627	109,153,256	28,456,627
1388			P	SG		727,390,873	189,633,289	727,390,873	189,633,289
1389			P	SG		-	-	-	-
1390					B8	945,571,653	246,513,764	945,571,653	246,513,764
1391									
1392	315	Accessory Electric Equipment							
1393			P	SG		85,763,790	22,358,913	85,763,790	22,358,913
1394			P	SG		133,124,041	34,705,893	133,124,041	34,705,893
1395			P	SG		204,707,307	53,367,895	204,707,307	53,367,895
1396			P	SG		-	-	-	-
1397					B8	423,595,138	110,432,701	423,595,138	110,432,701
1398									
1399									
1400									
1401	316	Misc Power Plant Equipment							
1402			P	SG		2,348,343	612,221	2,348,343	612,221
1403			P	SG		4,912,823	1,280,790	4,912,823	1,280,790
1404			P	SG		23,737,398	6,188,421	23,737,398	6,188,421
1405			P	SG		-	-	-	-
1406					B8	30,998,565	8,081,432	30,998,565	8,081,432

	2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2021 UNADJUSTED RESULTS TOTAL	 OREGON	DECEMBER 2023 NORMALIZED RESULTS TOTAL	 OREGON
1407									
1408	317	Steam Plant ARO							
1409			P	S		-	-	-	-
1410					B8	-	-	-	-
1411									
1412	SP	Unclassified Steam Plant - Account 300							
1413			P	SG		57,225,129	14,918,787	57,225,129	14,918,787
1414					B8	57,225,129	14,918,787	57,225,129	14,918,787
1415									
1416									
1417	**Total Steam Production Plant**				**B8**	**6,884,025,173**	**1,794,688,908**	**6,945,577,158**	**1,810,735,721**
1418									
1419									
1420	Summary of Steam Production Plant by Factor								
1421		S				-	-	-	-
1422		DGP				-	-	-	-
1423		DGU				-	-	-	-
1424		SG				6,884,025,173	1,794,688,908	6,945,577,158	1,810,735,721
1425		SSGCH				-	-	-	-
1426	Total Steam Production Plant by Factor					6,884,025,173	1,794,688,908	6,945,577,158	1,810,735,721
1427	320	Land and Land Rights							
1428			P	SG		-	-	-	-
1429			P	SG		-	-	-	-
1430					B8	-	-	-	-
1431									
1432	321	Structures and Improvements							
1433			P	SG		-	-	-	-
1434			P	SG	B8	-	-	-	-
1435						-	-	-	-
1436									
1437	322	Reactor Plant Equipment							
1438			P	SG		-	-	-	-
1439			P	SG		-	-	-	-
1440					B8	-	-	-	-
1441									
1442	323	Turbogenerator Units							
1443			P	SG		-	-	-	-
1444			P	SG		-	-	-	-
1445					B8	-	-	-	-
1446									
1447	324	Land and Land Rights							
1448			P	SG		-	-	-	-
1449			P	SG		-	-	-	-
1450					B8	-	-	-	-
1451									
1452	325	Misc. Power Plant Equipment							
1453			P	SG		-	-	-	-
1454			P	SG		-	-	-	-
1455					B8	-	-	-	-
1456									
1457									
1458	NP	Unclassified Nuclear Plant - Acct 300							
1459			P	SG		-	-	-	-
1460					B8	-	-	-	-
1461									
1462									
1463	**Total Nuclear Production Plant**				**B8**	**-**	**-**	**-**	**-**
1464									
1465									
1466									
1467	Summary of Nuclear Production Plant by Factor								
1468		DGP				-	-	-	-
1469		DGU				-	-	-	-
1470		SG				-	-	-	-
1471									
1472	Total Nuclear Plant by Factor					-	-	-	-
1473									
1474	330	Land and Land Rights							
1475			P	SG		10,332,372	2,693,685	10,332,372	2,693,685
1476			P	SG		5,268,322	1,373,470	5,268,322	1,373,470
1477			P	SG		21,965,016	5,726,355	21,965,016	5,726,355
1478			P	SG		1,316,755	343,282	1,316,755	343,282
1479					B8	38,882,464	10,136,791	38,882,464	10,136,791
1480									
1481	331	Structures and Improvements							
1482			P	SG		19,409,410	5,060,100	19,409,410	5,060,100
1483			P	SG		4,846,938	1,263,613	4,846,938	1,263,613
1484			P	SG		249,777,261	65,117,786	249,777,261	65,117,786
1485			P	SG		14,334,530	3,737,061	14,334,530	3,737,061
1486					B8	288,368,139	75,178,560	288,368,139	75,178,560

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
1487									
1488	332	Reservoirs, Dams & Waterways							
1489			P	SG		145,182,405	37,849,549	145,182,405	37,849,549
1490			P	SG		18,775,808	4,894,917	18,775,808	4,894,917
1491			P	SG		288,307,285	75,162,695	371,491,566	96,849,122
1492			P	SG		80,130,008	20,890,167	109,928,384	28,658,706
1493			0	SG		-	-	-	-
1494					B8	532,395,506	138,797,329	645,378,163	168,252,294
1495									
1496	333	Water Wheel, Turbines, & Generators							
1497			P	SG		28,717,970	7,486,873	28,717,970	7,486,873
1498			P	SG		6,749,763	1,759,686	6,749,763	1,759,686
1499			P	SG		67,204,973	17,520,566	67,204,973	17,520,566
1500			P	SG		43,566,039	11,357,815	43,566,039	11,357,815
1501					B8	146,238,745	38,124,941	146,238,745	38,124,941
1502									
1503	334	Accessory Electric Equipment							
1504			P	SG		3,653,216	952,406	3,653,216	952,406
1505			P	SG		3,335,903	869,681	3,335,903	869,681
1506			P	SG		67,845,688	17,687,603	67,845,688	17,687,603
1507			P	SG		11,197,573	2,919,246	11,197,573	2,919,246
1508					B8	86,032,381	22,428,936	86,032,381	22,428,936
1509									
1510									
1511									
1512	335	Misc. Power Plant Equipment							
1513			P	SG		1,129,697	294,516	1,129,697	294,516
1514			P	SG		153,991	40,146	153,991	40,146
1515			P	SG		1,261,938	328,991	1,261,938	328,991
1516			P	SG		18,279	4,765	18,279	4,765
1517					B8	2,563,904	668,419	2,563,904	668,419
1518									
1519	336	Roads, Railroads & Bridges							
1520			P	SG		4,363,451	1,137,566	4,363,451	1,137,566
1521			P	SG		734,401	191,461	734,401	191,461
1522			P	SG		18,843,685	4,912,613	18,843,685	4,912,613
1523			P	SG		2,333,429	608,333	2,333,429	608,333
1524					B8	26,274,965	6,849,973	26,274,965	6,849,973
1525									
1526	337	Hydro Plant ARO							
1527			P	S		-	-	-	-
1528					B8	-	-	-	-
1529									
1530	HP	Unclassified Hydro Plant - Acct 300							
1531			P	S		-	-	-	-
1532			P	SG		-	-	-	-
1533			P	SG		-	-	-	-
1534			P	SG		-	-	-	-
1535					B8	-	-	-	-
1536									
1537	**Total Hydraulic Production Plant**				**B8**	**1,120,756,105**	**292,184,950**	**1,233,738,762**	**321,639,915**
1538									
1539	Summary of Hydraulic Plant by Factor								
1540		S				-	-	-	-
1541		SG				1,120,756,105	292,184,950	1,233,738,762	321,639,915
1542		DGP				-	-	-	-
1543		DGU				-	-	-	-
1544	Total Hydraulic Plant by Factor					1,120,756,105	292,184,950	1,233,738,762	321,639,915
1545									
1546	340	Land and Land Rights							
1547			P	S		74,986	74,986	74,986	74,986
1548			P	SG		39,022,504	10,173,300	39,022,504	10,173,300
1549			P	SG		11,778,739	3,070,758	11,778,739	3,070,758
1550			P	SG		235,129	61,299	235,129	61,299
1551					B8	51,111,358	13,380,343	51,111,358	13,380,343
1552									
1553	341	Structures and Improvements							
1554				S		57,276	-	57,276	-
1555			P	SG		170,259,946	44,387,350	166,781,694	43,480,558
1556			P	SG		-	-	-	-
1557			P	SG		95,644,873	24,934,945	95,644,873	24,934,945
1558			P	SG		4,273,000	1,113,986	4,273,000	1,113,986
1559					B8	270,235,094	70,436,281	266,756,842	69,529,489
1560									
1561	342	Fuel Holders, Producers & Accessories							
1562			P	SG		13,623,206	3,551,616	13,623,206	3,551,616
1563			P	SG		-	-	-	-
1564			P	SG		2,759,334	719,368	2,759,334	719,368
1565					B8	16,382,540	4,270,984	16,382,540	4,270,984

	2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2021 UNADJUSTED RESULTS TOTAL	OREGON	DECEMBER 2023 NORMALIZED RESULTS TOTAL	OREGON
1566									
1567	343	Prime Movers							
1568			P	S		-	-	315,315	315,315
1569			P	SG		-	-	-	-
1570			P	SG		2,838,302,456	739,955,158	2,923,878,308	762,265,075
1571			P	SG		1,073,258,396	279,802,135	936,728,814	244,208,406
1572			P	SG		57,923,631	15,100,889	57,923,631	15,100,889
1573					B8	3,969,484,484	1,034,858,182	3,918,846,068	1,021,889,685
1574									
1575	344	Generators							
1576			P	S		234,822	-	234,822	-
1577			P	SG		162,285,484	42,308,381	162,285,484	42,308,381
1578			P	SG		406,478,931	105,970,448	398,548,375	103,902,925
1579			P	SG		17,782,763	4,636,027	17,782,763	4,636,027
1580					B8	586,781,999	152,914,855	578,851,444	150,847,332
1581									
1582	345	Accessory Electric Plant							
1583			P	S		66,364	-	66,364	-
1584			P	SG		211,261,475	55,076,589	198,825,092	51,834,382
1585			P	SG		236,973,020	61,779,677	236,973,020	61,779,677
1586			P	SG		-	-	-	-
1587			P	SG		2,901,493	756,429	2,901,493	756,429
1588					B8	451,202,352	117,612,695	438,765,970	114,370,488
1589									
1590									
1591									
1592	346	Misc. Power Plant Equipment							
1593			P	SG		12,618,225	3,289,614	11,958,728	3,117,681
1594			P	SG		10,950,697	2,854,884	10,950,697	2,854,884
1595			P	SG		-	-	-	-
1596					B8	23,568,922	6,144,499	22,909,425	5,972,566
1597									
1598	347	Other Production ARO							
1599			P	S		-	-	-	-
1600					B8	-	-	-	-
1601									
1602	OP	Unclassified Other Prod Plant-Acct 300							
1603			P	S		-	-	-	-
1604			P	SG		(553,173)	(144,214)	(553,173)	(144,214)
1605						(553,173)	(144,214)	(553,173)	(144,214)
1606									
1607	**Total Other Production Plant**				**B8**	**5,368,213,576**	**1,399,473,625**	**5,293,070,474**	**1,380,116,672**
1608									
1609	Summary of Other Production Plant by Factor								
1610		S				433,448	74,986	748,763	390,301
1611		DGU				-	-	-	-
1612		SG				5,367,780,129	1,399,398,639	5,292,321,711	1,379,726,371
1613		SSGCT				-	-	-	-
1614	Total of Other Production Plant by Factor					5,368,213,576	1,399,473,625	5,293,070,474	1,380,116,672
1615									
1616	Experimental Plant								
1617	103	Experimental Plant							
1618			P	SG		-	-	-	-
1619	**Total Experimental Production Plant**				**B8**	**-**	**-**	**-**	**-**
1620									
1621	**Total Production Plant**				**B8**	**13,372,994,855**	**3,486,347,482**	**13,472,386,393**	**3,512,492,308**
1622	350	Land and Land Rights							
1623			T	SG		20,985,485	5,470,988	20,985,485	5,470,988
1624			T	SG		47,180,383	12,300,087	47,180,383	12,300,087
1625			T	SG		241,708,765	63,014,302	241,708,765	63,014,302
1626					B8	309,874,633	80,785,377	309,874,633	80,785,377
1627									
1628	352	Structures and Improvements							
1629			T	S		-	-	-	-
1630			T	SG		6,948,990	1,811,625	6,948,990	1,811,625
1631			T	SG		17,672,992	4,607,410	17,672,992	4,607,410
1632			T	SG		288,409,158	75,189,254	288,171,340	75,127,254
1633					B8	313,031,140	81,608,289	312,793,322	81,546,289
1634									
1635	353	Station Equipment							
1636			T	SG		104,538,598	27,253,570	104,538,598	27,253,570
1637			T	SG		152,203,195	39,679,893	152,203,195	39,679,893
1638			T	SG		2,084,932,097	543,548,929	2,084,932,097	543,548,929
1639					B8	2,341,673,890	610,482,392	2,341,673,890	610,482,392
1640									
1641	354	Towers and Fixtures							
1642			T	SG		128,106,134	33,397,707	128,106,134	33,397,707
1643			T	SG		131,221,291	34,209,839	131,221,291	34,209,839
1644			T	SG		1,074,113,720	280,025,120	1,074,113,720	280,025,120
1645					B8	1,333,441,145	347,632,667	1,333,441,145	347,632,667
1646									

	2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2021 UNADJUSTED RESULTS TOTAL	 OREGON	DECEMBER 2023 NORMALIZED RESULTS TOTAL	 OREGON
1647	355	Poles and Fixtures							
1648			T	SG		59,871,353	15,608,667	59,871,353	15,608,667
1649			T	SG		113,621,585	29,621,536	113,621,585	29,621,536
1650			T	SG		935,765,327	243,957,221	1,243,846,459	324,275,026
1651					B8	1,109,258,265	289,187,424	1,417,339,397	369,505,228
1652									
1653	356	Clearing and Grading							
1654			T	SG		157,481,552	41,055,979	157,481,552	41,055,979
1655			T	SG		157,154,432	40,970,698	157,154,432	40,970,698
1656			T	SG		1,064,442,587	277,503,823	1,064,442,587	277,503,823
1657					B8	1,379,078,572	359,530,500	1,379,078,572	359,530,500
1658									
1659	357	Underground Conduit							
1660			T	SG		6,371	1,661	6,371	1,661
1661			T	SG		91,651	23,894	91,651	23,894
1662			T	SG		3,759,944	980,230	3,759,944	980,230
1663					B8	3,857,965	1,005,785	3,857,965	1,005,785
1664									
1665	358	Underground Conductors							
1666			T	SG		-	-	-	-
1667			T	SG		1,087,552	283,529	1,087,552	283,529
1668			T	SG		7,993,065	2,083,819	7,993,065	2,083,819
1669					B8	9,080,617	2,367,348	9,080,617	2,367,348
1670									
1671	359	Roads and Trails							
1672			T	SG		1,863,032	485,699	1,863,032	485,699
1673			T	SG		440,513	114,843	440,513	114,843
1674			T	SG		9,842,468	2,565,965	9,842,468	2,565,965
1675					B8	12,146,013	3,166,507	12,146,013	3,166,507
1676									
1677	TP	Unclassified Trans Plant - Acct 300							
1678			T	SG		924,562,138	241,036,512	924,562,138	241,036,512
1679					B8	924,562,138	241,036,512	924,562,138	241,036,512
1680									
1681	TS0	Unclassified Trans Sub Plant - Acct 300							
1682			T	SG		-	-	-	-
1683					B8	-	-	-	-
1684									
1685	**Total Transmission Plant**				**B8**	**7,736,004,378**	**2,016,802,800**	**8,043,847,692**	**2,097,058,605**
1686	Summary of Transmission Plant by Factor								
1687			DGP			-	-	-	-
1688			DGU			-	-	-	-
1689			SG			7,736,004,378	2,016,802,800	8,043,847,692	2,097,058,605
1690	Total Transmission Plant by Factor					7,736,004,378	2,016,802,800	8,043,847,692	2,097,058,605
1691	360	Land and Land Rights							
1692			DPW	S		66,395,110	14,306,812	71,858,475	15,341,593
1693					B8	66,395,110	14,306,812	71,858,475	15,341,593
1694									
1695	361	Structures and Improvements							
1696			DPW	S		125,858,575	32,761,372	136,094,930	34,602,903
1697					B8	125,858,575	32,761,372	136,094,930	34,602,903
1698									
1699	362	Station Equipment							
1700			DPW	S		1,044,297,304	262,150,735	1,130,227,989	278,426,317
1701					B8	1,044,297,304	262,150,735	1,130,227,989	278,426,317
1702									
1703	363	Storage Battery Equipment							
1704			DPW	S		-	-	-	-
1705					B8	-	-	-	-
1706									
1707	364	Poles, Towers & Fixtures							
1708			DPW	S		1,364,781,739	452,281,633	1,477,083,695	473,552,029
1709					B8	1,364,781,739	452,281,633	1,477,083,695	473,552,029
1710									
1711	365	Overhead Conductors							
1712			DPW	S		858,809,016	299,985,292	929,476,676	313,370,002
1713					B8	858,809,016	299,985,292	929,476,676	313,370,002
1714									
1715	366	Underground Conduit							
1716			DPW	S		426,082,888	106,676,187	461,143,396	113,316,773
1717					B8	426,082,888	106,676,187	461,143,396	113,316,773
1718									
1719									
1720									
1721									
1722	367	Underground Conductors							
1723			DPW	S		993,965,104	208,212,087	1,075,754,171	223,703,231
1724					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	JUNE 2021 UNADJUSTED RESULTS OREGON	DECEMBER 2023 NORMALIZED RESULTS TOTAL	DECEMBER 2023 NORMALIZED RESULTS OREGON
1725									
1726	368	Line Transformers							
1727			DPW	S		1,504,533,721	498,477,508	1,628,335,259	521,925,966
1728					B8	1,504,533,721	498,477,508	1,628,335,259	521,925,966
1729									
1730	369	Services							
1731			DPW	S		930,367,417	325,742,456	1,006,923,307	340,242,418
1732					B8	930,367,417	325,742,456	1,006,923,307	340,242,418
1733									
1734	370	Meters							
1735			DPW	S		254,673,505	97,716,304	275,629,480	101,685,442
1736					B8	254,673,505	97,716,304	275,629,480	101,685,442
1737									
1738	371	Installations on Customers' Premises							
1739			DPW	S		8,805,282	2,666,274	9,529,830	2,803,506
1740					B8	8,805,282	2,666,274	9,529,830	2,803,506
1741									
1742	372	Leased Property							
1743			DPW	S		-	-	-	-
1744					B8	-	-	-	-
1745									
1746	373	Street Lights							
1747			DPW	S		63,059,406	24,884,170	68,248,290	25,866,963
1748					B8	63,059,406	24,884,170	68,248,290	25,866,963
1749									
1750	DP	Unclassified Dist Plant - Acct 300							
1751			DPW	S		161,745,166	39,370,985	161,745,166	39,370,985
1752					B8	161,745,166	39,370,985	161,745,166	39,370,985
1753									
1754	DS0	Unclassified Dist Sub Plant - Acct 300							
1755			DPW	S		-	-	-	-
1756					B8	-	-	-	-
1757									
1758									
1759	**Total Distribution Plant**				**B8**	**7,803,374,232**	**2,365,231,816**	**8,432,050,664**	**2,484,208,127**
1760									
1761	Summary of Distribution Plant by Factor								
1762		S				7,803,374,232	2,365,231,816	8,432,050,664	2,484,208,127
1763									
1764	Total Distribution Plant by Factor					7,803,374,232	2,365,231,816	8,432,050,664	2,484,208,127
1765	389	Land and Land Rights							
1766			G-SITUS	S		15,079,558	6,116,556	15,079,558	6,116,556
1767			CUST	CN		1,128,506	349,723	1,128,506	349,723
1768			G-DGU	SG		332	87	332	87
1769			G-SG	SG		1,228	320	1,228	320
1770			PTD	SO		7,611,617	2,068,311	7,611,617	2,068,311
1771					B8	23,821,241	8,534,997	23,821,241	8,534,997
1772									
1773	390	Structures and Improvements							
1774			G-SITUS	S		137,788,608	40,901,786	137,788,608	40,901,786
1775			G-DGP	SG		335,238	87,398	335,238	87,398
1776			G-DGU	SG		1,356,387	353,615	1,356,387	353,615
1777			CUST	CN		8,207,715	2,543,565	8,207,715	2,543,565
1778			G-SG	SG		10,392,416	2,709,338	10,392,416	2,709,338
1779			P	SE		888,035	222,614	888,035	222,614
1780			PTD	SO		101,391,609	27,551,225	101,391,609	27,551,225
1781					B8	260,360,008	74,369,541	260,360,008	74,369,541
1782									
1783	391	Office Furniture & Equipment							
1784			G-SITUS	S		7,401,451	2,404,388	7,401,451	2,404,388
1785			G-DGP	SG		-	-	-	-
1786			G-DGU	SG		-	-	-	-
1787			CUST	CN		4,028,345	1,248,381	4,028,345	1,248,381
1788			G-SG	SG		4,114,866	1,072,760	4,114,866	1,072,760
1789			P	SE		31,954	8,010	31,954	8,010
1790			PTD	SO		60,767,447	16,512,388	60,767,447	16,512,388
1791			G-SG	SG		-	-	-	-
1792			G-SG	SG		4,039	1,053	4,039	1,053
1793					B8	76,348,102	21,246,980	76,348,102	21,246,980

	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
1794									
1795	392	Transportation Equipment							
1796			G-SITUS	S		101,190,413	26,003,370	101,190,413	26,003,370
1797			PTD	SO		7,764,904	2,109,964	7,764,904	2,109,964
1798			G-SG	SG		23,530,085	6,134,374	23,530,085	6,134,374
1799			CUST	CN		-	-	-	-
1800			G-DGU	SG		401,191	104,592	401,191	104,592
1801			P	SE		327,360	82,063	327,360	82,063
1802			G-DGP	SG		70,616	18,410	70,616	18,410
1803			G-SG	SG		-	-	-	-
1804			G-DGU	SG		44,655	11,642	44,655	11,642
1805					B8	133,329,224	34,464,413	133,329,224	34,464,413
1806									
1807	393	Stores Equipment							
1808			G-SITUS	S		9,087,544	2,735,814	9,087,544	2,735,814
1809			G-DGP	SG		-	-	-	-
1810			G-DGU	SG		-	-	-	-
1811			PTD	SO		248,585	67,548	248,585	67,548
1812			G-SG	SG		6,008,319	1,566,389	6,008,319	1,566,389
1813			G-DGU	SG		53,971	14,070	53,971	14,070
1814					B8	15,398,418	4,383,821	15,398,418	4,383,821
1815									
1816	394	Tools, Shop & Garage Equipment							
1817			G-SITUS	S		36,331,376	10,914,668	36,331,376	10,914,668
1818			G-DGP	SG		37,684	9,824	37,684	9,824
1819			G-SG	SG		21,689,441	5,654,511	21,689,441	5,654,511
1820			PTD	SO		1,959,768	532,529	1,959,768	532,529
1821			P	SE		125,691	31,508	125,691	31,508
1822			G-DGU	SG		-	-	-	-
1823			G-SG	SG		-	-	-	-
1824			G-SG	SG		89,913	23,441	89,913	23,441
1825					B8	60,233,874	17,166,482	60,233,874	17,166,482
1826									
1827	395	Laboratory Equipment							
1828			G-SITUS	S		23,539,739	9,565,368	23,539,739	9,565,368
1829			G-DGP	SG		-	-	-	-
1830			G-DGU	SG		-	-	-	-
1831			PTD	SO		4,872,934	1,324,126	4,872,934	1,324,126
1832			P	SE		1,343,231	336,723	1,343,231	336,723
1833			G-SG	SG		6,447,642	1,680,922	6,447,642	1,680,922
1834			G-SG	SG		-	-	-	-
1835			G-SG	SG		14,022	3,655	14,022	3,655
1836					B8	36,217,568	12,910,795	36,217,568	12,910,795
1837									
1838	396	Power Operated Equipment							
1839			G-SITUS	S		154,961,157	44,851,927	154,961,157	44,851,927
1840			G-DGP	SG		262,000	68,304	262,000	68,304
1841			G-SG	SG		45,162,242	11,773,951	45,162,242	11,773,951
1842			PTD	SO		8,335,763	2,265,084	8,335,763	2,265,084
1843			G-DGU	SG		924,826	241,105	924,826	241,105
1844			P	SE		236,686	59,333	236,686	59,333
1845			P	SG		-	-	-	-
1846			G-SG	SG		-	-	-	-
1847					B8	209,882,674	59,259,704	209,882,674	59,259,704
1848	397	Communication Equipment							
1849			G-SITUS	S		201,031,280	80,037,895	272,972,646	99,466,592
1850			G-DGP	SG		301,777	78,674	301,777	78,674
1851			G-DGU	SG		139,259	36,305	139,259	36,305
1852			PTD	SO		94,039,446	25,553,416	149,911,488	40,735,572
1853			CUST	CN		3,848,526	1,192,655	2,058,814	638,025
1854			G-SG	SG		182,194,294	47,498,676	190,670,129	49,708,355
1855			P	SE		361,776	90,690	93,619	23,469
1856			G-SG	SG		-	-	-	-
1857			G-SG	SG		16,633	4,336	16,633	4,336
1858					B8	481,932,990	154,492,648	616,164,365	190,691,327
1859									
1860	398	Misc. Equipment							
1861			G-SITUS	S		3,167,859	1,225,125	3,167,859	1,225,125
1862			G-DGP	SG		-	-	-	-
1863			G-DGU	SG		-	-	-	-
1864			CUST	CN		82,497	25,566	82,497	25,566
1865			PTD	SO		2,228,810	605,636	2,228,810	605,636
1866			P	SE		3,966	994	3,966	994
1867			G-SG	SG		2,872,099	748,766	2,872,099	748,766
1868			G-SG	SG		-	-	-	-
1869					B8	8,355,230	2,606,087	8,355,230	2,606,087

	2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2021 UNADJUSTED RESULTS TOTAL	 OREGON	DECEMBER 2023 NORMALIZED RESULTS TOTAL	 OREGON
1870									
1871	399	Coal Mine							
1872			P	SE		1,822,901	456,967	50,741,701	12,719,998
1873	MP		P	SE		-	-	-	-
1874					B8	1,822,901	456,967	50,741,701	12,719,998
1875									
1876	399L	WIDCO Capital Lease							
1877			P	SE		-	-	-	-
1878						-	-	-	-
1879									
1880		Remove Capital Leases				-	-	-	-
1881						-	-	-	-
1882									
1883	1011390	General Capital Leases							
1884			G-SITUS	S		4,168,467	1,612,664	4,168,467	1,612,664
1885			P	SG		9,880,847	2,575,971	9,880,847	2,575,971
1886			PTD	SO		-	-	-	-
1887					B9	14,049,314	4,188,634	14,049,314	4,188,634
1888									
1889		Remove Capital Leases				(14,049,314)	(4,188,634)	(14,049,314)	(4,188,634)
1890						-	-	-	-
1891									
1892	1011346	General Gas Line Capital Leases							
1893			P	SG		-	-	-	-
1894					B9	-	-	-	-
1895									
1896		Remove Capital Leases				-	-	-	-
1897						-	-	-	-
1898									
1899	GP	Unclassified Gen Plant - Acct 300							
1900			G-SITUS	S		-	-	-	-
1901			PTD	SO		61,631,793	16,747,258	61,631,793	16,747,258
1902			CUST	CN		-	-	-	-
1903			G-SG	SG		-	-	-	-
1904			G-DGP	SG		-	-	-	-
1905			G-DGU	SG		-	-	-	-
1906					B8	61,631,793	16,747,258	61,631,793	16,747,258
1907									
1908	399G	Unclassified Gen Plant - Acct 300							
1909			G-SITUS	S		-	-	-	-
1910			PTD	SO		-	-	-	-
1911			G-SG	SG		-	-	-	-
1912			G-DGP	SG		-	-	-	-
1913			G-DGU	SG		-	-	-	-
1914					B8	-	-	-	-
1915									
1916	**Total General Plant**				**B8**	**1,369,334,022**	**406,639,694**	**1,552,484,198**	**455,101,404**
1917									
1918	Summary of General Plant by Factor								
1919		S				693,747,452	226,369,560	765,688,819	245,798,256
1920		DGP				-	-	-	-
1921		DGU				-	-	-	-
1922		SG				316,346,020	82,472,489	324,821,855	84,682,168
1923		SO				350,852,677	95,337,485	406,724,719	110,519,641
1924		SE				5,141,598	1,288,903	53,792,243	13,484,712
1925		CN				17,295,589	5,359,891	15,505,877	4,805,260
1926		DEU				-	-	-	-
1927		SSGCT				-	-	-	-
1928		SSGCH				-	-	-	-
1929		Less Capital Leases				(14,049,314)	(4,188,634)	(14,049,314)	(4,188,634)
1930	Total General Plant by Factor					1,369,334,022	406,639,694	1,552,484,198	455,101,404
1931	301	Organization							
1932			I-SITUS	S		-	-	-	-
1933			PTD	SO		-	-	-	-
1934			I-SG	SG		-	-	-	-
1935					B8	-	-	-	-
1936	302	Franchise & Consent							
1937			I-SITUS	S		(31,081,215)	-	(31,081,215)	-
1938			I-SG	SG		13,159,840	3,430,815	12,027,142	3,135,517
1939			I-SG	SG		177,566,825	46,292,279	177,482,844	46,270,384
1940			I-SG	SG		10,014,897	2,610,918	9,746,329	2,540,901
1941			I-DGP	SG		-	-	-	-
1942			I-DGU	SG		477,596	124,511	477,596	124,511
1943					B8	170,137,943	52,458,523	168,652,697	52,071,314

	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
1944									
1945	303	Miscellaneous Intangible Plant							
1946			I-SITUS	S		22,092,897	4,616,002	21,935,586	4,609,463
1947			I-SG	SG		197,523,407	51,495,028	197,523,407	51,495,028
1948			PTD	SO		432,009,413	117,390,272	476,788,634	129,558,166
1949			P	SE		9,106	2,283	(64,323)	(16,125)
1950			CUST	CN		214,248,773	66,395,542	213,633,287	66,204,803
1951			P	SG		-	-	-	-
1952			I-DGP	SG		-	-	-	-
1953					B8	865,883,596	239,899,126	909,816,590	251,851,335
1954	303	Less Non-Regulated Plant							
1955			I-SITUS	S		-	-	-	-
1956						865,883,596	239,899,126	909,816,590	251,851,335
1957	IP	Unclassified Intangible Plant - Acct 300							
1958			I-SITUS	S		-	-	-	-
1959			I-SG	SG		-	-	-	-
1960			I-DGU	SG		-	-	-	-
1961			PTD	SO		-	-	-	-
1962						-	-	-	-
1963									
1964	**Total Intangible Plant**				**B8**	**1,036,021,539**	**292,357,649**	**1,078,469,287**	**303,922,649**
1965									
1966	Summary of Intangible Plant by Factor								
1967		S				(8,988,318)	4,616,002	(9,145,629)	4,609,463
1968		DGP				-	-	-	-
1969		DGU				-	-	-	-
1970		SG				398,742,565	103,953,550	397,257,319	103,566,342
1971		SO				432,009,413	117,390,272	476,788,634	129,558,166
1972		CN				214,248,773	66,395,542	213,633,287	66,204,803
1973		SSGCT				-	-	-	-
1974		SSGCH				-	-	-	-
1975		SE				9,106	2,283	(64,323)	(16,125)
1976	Total Intangible Plant by Factor					1,036,021,539	292,357,649	1,078,469,287	303,922,649
1977	Summary of Unclassified Plant (Account 106)								
1978		DP				161,745,166	39,370,985	161,745,166	39,370,985
1979		DS0				-	-	-	-
1980		GP				61,631,793	16,747,258	61,631,793	16,747,258
1981		HP				-	-	-	-
1982		NP				-	-	-	-
1983		OP				(553,173)	(144,214)	(553,173)	(144,214)
1984		TP				924,562,138	241,036,512	924,562,138	241,036,512
1985		TS0				-	-	-	-
1986		IP				-	-	-	-
1987		MP				-	-	-	-
1988		SP				57,225,129	14,918,787	57,225,129	14,918,787
1989	Total Unclassified Plant by Factor					1,204,611,053	311,929,327	1,204,611,053	311,929,327
1990									
1991	**Total Electric Plant In Service**				**B8**	**31,317,729,025**	**8,567,379,441**	**32,579,238,234**	**8,852,783,093**
1992	Summary of Electric Plant by Factor								
1993		S				8,488,566,813	2,596,292,363	9,189,342,617	2,735,006,147
1994		SE				5,150,704	1,291,185	53,727,919	13,468,587
1995		DGU				-	-	-	-
1996		DGP				-	-	-	-
1997		SG				21,823,654,370	5,689,501,337	22,237,564,495	5,797,409,122
1998		SO				782,862,090	212,727,757	883,513,353	240,077,807
1999		CN				231,544,362	71,755,433	229,139,163	71,010,064
2000		DEU				-	-	-	-
2001		SSGCH				-	-	-	-
2002		SSGCT				-	-	-	-
2003		Less Capital Leases				(14,049,314)	(4,188,634)	(14,049,314)	(4,188,634)
2004						31,317,729,025	8,567,379,441	32,579,238,234	8,852,783,093
2005	105	Plant Held For Future Use							
2006			DPW	S		13,293,032	6,893,577	-	-
2007			P	SG		-	-	-	-
2008			T	SG		1,679,914	437,959	1,679,914	437,959
2009			P	SG		8,923,302	2,326,335	8,923,302	2,326,335
2010			P	SE		-	-	-	-
2011			G	SG		-	-	(10,603,216)	(2,764,295)
2012									
2013									
2014	**Total Plant Held For Future Use**				**B10**	**23,896,248**	**9,657,872**	**-**	**-**
2015									
2016	114	Electric Plant Acquisition Adjustments							
2017			P	S		11,763,784	-	11,763,784	-
2018			P	SG		144,704,699	37,725,010	3,518,456	917,274
2019			P	SG		-	-	-	-
2020	**Total Electric Plant Acquisition Adjustment**				**B15**	**156,468,483**	**37,725,010**	**15,282,240**	**917,274**

	2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2021 UNADJUSTED RESULTS TOTAL	OREGON	DECEMBER 2023 NORMALIZED RESULTS TOTAL	OREGON
2021									
2022	115	Accum Provision for Asset Acquisition Adjustments							
2023			P	S		(3,612,186)	-	(3,612,186)	-
2024			P	SG		(137,980,477)	(35,971,982)	(827,259)	(215,669)
2025			P	SG		-	-	-	-
2026					B15	(141,592,663)	(35,971,982)	(4,439,444)	(215,669)
2027									
2028	128	Pensions							
2029			LABOR	SO		28,656,862	7,786,953	-	-
2030	**Total Pensions**				**B15**	**28,656,862**	**7,786,953**	**-**	**-**
2031									
2032	124	Weatherization							
2033			DMSC	S		629,485	-	629,485	-
2034			DMSC	SO		-	-	-	-
2035					B16	629,485	-	629,485	-
2036									
2037	182W	Weatherization							
2038			DMSC	S		198,594,752	-	198,594,752	-
2039			DMSC	SG		-	-	-	-
2040			DMSC	SGCT		-	-	-	-
2041			DMSC	SO		-	-	-	-
2042					B16	198,594,752	-	198,594,752	-
2043									
2044	186W	Weatherization							
2045			DMSC	S		-	-	-	-
2046			DMSC	CN		-	-	-	-
2047			DMSC	CNP		-	-	-	-
2048			DMSC	SG		-	-	-	-
2049			DMSC	SO		-	-	-	-
2050					B16	-	-	-	-
2051									
2052	**Total Weatherization**				**B16**	**199,224,237**	**-**	**199,224,237**	**-**
2053									
2054	151	Fuel Stock							
2055			P	DEU		-	-	-	-
2056			P	SE		206,953,359	51,879,348	177,743,272	44,556,924
2057			P	SE		-	-	-	-
2058			P	SE		-	-	-	-
2059					B13	206,953,359	51,879,348	177,743,272	44,556,924
2060									
2061	152	Fuel Stock - Undistributed							
2062			P	SE		-	-	-	-
2063						-	-	-	-
2064									
2065	25316	UAMPS Working Capital Deposit							
2066			P	SE		(2,806,000)	(703,412)	(2,803,000)	(702,660)
2067					B13	(2,806,000)	(703,412)	(2,803,000)	(702,660)
2068									
2069	25317	DG&T Working Capital Deposit							
2070			P	SE		(2,675,523)	(670,704)	(2,641,354)	(662,138)
2071					B13	(2,675,523)	(670,704)	(2,641,354)	(662,138)
2072									
2073	25319	Provo Working Capital Deposit							
2074			P	SE		-	-	-	-
2075						-	-	-	-
2076									
2077	**Total Fuel Stock**				**B13**	**201,471,836**	**50,505,232**	**172,298,918**	**43,192,126**
2078	154	Materials and Supplies							
2079			MSS	S		142,474,539	49,096,450	142,474,539	49,096,450
2080			MSS	SG		4,837,325	1,261,107	(504,572)	(131,544)
2081			MSS	SE		-	-	-	-
2082			MSS	SO		(1,284,248)	(348,970)	(1,284,248)	(348,970)
2083			MSS	SG		120,142,856	31,321,653	120,142,856	31,321,653
2084			MSS	SG		7,954	2,074	7,954	2,074
2085			MSS	SNPD		(1,308,783)	(346,469)	(1,308,783)	(346,469)
2086			MSS	SG		-	-	-	-
2087			MSS	SG		-	-	-	-
2088			MSS	SG		-	-	-	-
2089			MSS	SG		-	-	-	-
2090			MSS	SG		8,430,223	2,197,788	8,430,223	2,197,788
2091			MSS	SG		-	-	-	-
2092					B13	273,299,865	83,183,634	267,957,968	81,790,983
2093									
2094	163	Stores Expense Undistributed							
2095			MSS	SO		-	-	-	-
2096									
2097					B13	-	-	-	-

	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
2098									
2099	25318	Provo Working Capital Deposit							
2100			MSS	SG		(273,000)	(71,172)	(273,000)	(71,172)
2101									
2102					B13	(273,000)	(71,172)	(273,000)	(71,172)
2103									
2104	**Total Materials and Supplies**				**B13**	**273,026,865**	**83,112,462**	**267,684,968**	**81,719,811**
2105									
2106	165	Prepayments							
2107			DMSC	S		41,441,441	4,077,479	41,441,441	4,077,479
2108			GP	GPS		160,162	43,521	160,162	43,521
2109			PT	SG		3,834,288	999,612	3,834,288	999,612
2110			P	SE		45,735	11,465	45,735	11,465
2111			PTD	SO		22,072,726	5,997,840	22,072,726	5,997,840
2112	**Total Prepayments**				**B15**	**67,554,352**	**11,129,917**	**67,554,352**	**11,129,917**
2113									
2114	182M	Misc Regulatory Assets							
2115			DDS2	S		184,523,735	(11,607,347)	196,131,082	-
2116			DEFSG	SG		6,984,837	1,820,971	2,344,579	611,240
2117			P	SGCT		-	-	-	-
2118			DEFSG	SG-P		-	-	-	-
2119			P	SE		193,501,291	48,507,165	115,119,099	28,858,211
2120			P	SG		-	-	-	-
2121			DDSO2	SO		460,943,527	125,252,562	45,802,824	12,446,039
2122					B16	845,953,389	163,973,351	359,397,585	41,915,490
2123									
2124	186M	Misc Deferred Debits							
2125			LABOR	S		2,443,884	-	2,443,884	-
2126			P	SG		-	-	-	-
2127			P	SG		-	-	-	-
2128			DEFSG	SG		113,459,708	29,579,334	96,510,696	25,160,668
2129			LABOR	SO		78,384	21,299	78,384	21,299
2130			P	SE		809,282	202,872	809,282	202,872
2131			P	SG		-	-	-	-
2132			GP	EXCTAX		-	-	-	-
2133	**Total Misc. Deferred Debits**				**B11**	**116,791,258**	**29,803,505**	**99,842,246**	**25,384,840**
2134									
2135	Working Capital								
2136	CWC	Cash Working Capital							
2137			CWC	S		30,454,966	8,611,296	29,774,416	8,503,482
2138			CWC	SO		-	-	-	-
2139			CWC	SE		-	-	-	-
2140					B14	30,454,966	8,611,296	29,774,416	8,503,482
2141									
2142	OWC	Other Work. Cap.							
2143	131	Cash	GP	SNP		-	-	-	-
2144	135	Working Funds	GP	SG		-	-	-	-
2145	141	Notes Receivable	GP	SO		-	-	-	-
2146	143	Other A/R	GP	SO		38,636,523	10,498,734	38,636,523	10,498,734
2147	232	A/P	PTD	S		(18,882)	-	(18,882)	-
2148	232	A/P	PTD	SO		(6,155,803)	(1,672,721)	(6,155,803)	(1,672,721)
2149	232	A/P	P	SE		(3,116,112)	(781,151)	(3,116,112)	(781,151)
2150	232	A/P	T	SG		(3,331,340)	(868,492)	(3,331,340)	(868,492)
2151	2533	Other Msc. Df. Crd.	P	S		-	-	-	-
2152	2533	Other Msc. Df. Crd.	P	SE		(7,150,412)	(1,792,475)	(9,303,790)	(2,332,287)
2153	230	Asset Retir. Oblig.	P	SG		-	-	-	-
2154	230	Asset Retir. Oblig.	P	S		(2,978,037)	-	(2,978,037)	-
2155	254	Decom. Reg Liability	P	SG		-	-	-	-
2156	254	Reclam. Reg Liability	P	SE		-	-	-	-
2157	2533	Cholla Reclamation	P	SE		-	-	-	-
2158					B14	15,885,936	5,383,895	13,732,558	4,844,083
2159									
2160	**Total Working Capital**				**B14**	**46,340,902**	**13,995,191**	**43,506,974**	**13,347,565**
2161	Miscellaneous Rate Base								
2162	18221	Unrec Plant & Reg Study Costs							
2163			P	S		-	-	-	-
2164									
2165						-	-	-	-
2166									
2167	18222	Nuclear Plant - Trojan							
2168			P	S		-	-	-	-
2169			P	TROJP		-	-	-	-
2170			P	TROJD		-	-	-	-
2171					B16	-	-	-	-

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
2172									
2173									
2174									
2175	1869	Misc Deferred Debits-Trojan							
2176			P	S		-	-	-	-
2177			P	SG		-	-	-	-
2178						-	-	-	-
2179									
2180	**Total Miscellaneous Rate Base**				**B15**	**-**	**-**	**-**	**-**
2181									
2182	**Total Rate Base Additions**					**1,817,791,769**	**371,717,509**	**1,220,352,075**	**217,391,352**
2183	235	Customer Service Deposits							
2184			CUST	S		-	-	-	-
2185			CUST	CN		-	-	-	-
2186	**Total Customer Service Deposits**				B15	**-**	**-**	**-**	**-**
2187									
2188	2281	Prop Ins	PTD	S		(5,903,206)	20,937,606	(5,903,206)	20,937,606
2189	2282	Inj & Dam	PTD	SO		(141,155,665)	(38,356,344)	-	-
2190	2283	Pen & Ben	PTD	SO		(76,044,531)	(20,663,643)	(1,612,198)	(438,084)
2191	2282	Prov for Injurie	PTD	S		(12,416,392)	(12,416,392)	(12,416,392)	(12,416,392)
2192	254	Reg Liabilities	PTD	SO		(11,202,836)	(3,044,156)	(11,202,836)	(3,044,156)
2193	25335	Reg Liabilities	PTD	SE		(115,119,099)	(28,858,211)	(115,119,099)	(28,858,211)
2194					B15	(361,841,730)	(82,401,140)	(146,253,732)	(23,819,237)
2195									
2196	22841	Accum Misc. Operating Provisions							
2197			P	S		-	-	-	-
2198			P	SG		(234,853)	(61,227)	(234,853)	(61,227)
2199					B15	(234,853)	(61,227)	(234,853)	(61,227)
2200									
2201	254105	ARO	P	S		-	-	-	-
2202	230	ARO	P	TROJD		(5,565,959)	(1,441,094)	(5,565,959)	(1,441,094)
2203	254105	ARO	P	TROJD		-	-	-	-
2204	254		P	S		(1,823,401,237)	(385,458,427)	(1,807,135,161)	(369,192,352)
2205					B15	(1,828,967,196)	(386,899,522)	(1,812,701,121)	(370,633,446)
2206									
2207	252	Customer Advances for Construction							
2208			DPW	S		(1,709,876)	(1,424,117)	(23,708,755)	(2,069,907)
2209			DPW	SE		-	-	-	-
2210			T	SG		(102,399,151)	(26,695,809)	(80,400,272)	(20,960,626)
2211			DPW	SO		-	-	-	-
2212			CUST	CN		-	-	-	-
2213	**Total Customer Advances for Construction**				**B20**	**(104,109,027)**	**(28,119,926)**	**(104,109,027)**	**(23,030,533)**
2214									
2215	25398	SO2 Emissions							
2216			P	SE		-	-	-	-
2217						-	-	-	-
2218									
2219	25399	Other Deferred Credits							
2220			P	S		(405,265)	(204,430)	(405,265)	(204,430)
2221			LABOR	SO		-	-	-	-
2222			P	SG		(63,848,335)	(16,645,479)	(63,848,335)	(16,645,479)
2223			P	SE		(14,598,111)	(3,659,474)	(14,598,111)	(3,659,474)
2224					B15	(78,851,712)	(20,509,383)	(78,851,712)	(20,509,383)
2225									
2226	190	Accumulated Deferred Income Taxes							
2227			P	S		455,694,550	97,713,118	437,493,308	93,571,742
2228			CUST	CN		-	-	-	-
2229			LABOR	SO		126,177,788	34,286,394	53,932,101	14,655,014
2230			P	DGP		-	-	-	-
2231			IBT	IBT		-	-	-	-
2232			P	SG		-	-	-	-
2233			P	SG		-	-	-	-
2234			CUST	BADDEBT		4,646,301	2,252,764	4,933,337	2,391,934
2235			P	TROJD		1,298,701	336,249	1,288,724	333,666
2236			P	SG		1,952,500	509,023	1,374,949	358,454
2237			P	SE		31,308,246	7,848,393	1,888,088	473,309
2238			PTD	SNP		-	-	-	-
2239			DPW	SNPD		691,719	183,116	1,546,918	409,509
2240			P	SG		-	-	-	-
2241					B19	621,769,805	143,129,058	502,457,426	112,193,627
2242									
2243	281	Accumulated Deferred Income Taxes							
2244			P	S		-	-	-	-
2245			PT	SG		(148,004,159)	(38,585,191)	(0)	(0)
2246			T	SG		-	-	-	-
2247					B19	(148,004,159)	(38,585,191)	(0)	(0)

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
282	Accumulated Deferred Income Taxes							
		GP	S		7,269,546	-	(3,063,425,893)	(741,897,489)
		ACCMDIT	DITBAL		(2,746,244,293)	(672,919,492)	(383,942)	(94,078)
		PT	SNP		(961,671)	(246,174)	(883,760)	(226,230)
		LABOR	SO		42,717	11,608	(1,050,898)	(285,561)
		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)	(625,167)	(590,431)	(148,010)
		P	SG		(0)	(0)	5,324,605	1,388,143
				B19	(2,742,387,572)	(673,779,226)	(3,061,016,312)	(741,265,083)
283	Accumulated Deferred Income Taxes							
		GP	S		(107,775,044)	(3,667,618)	(113,099,970)	(5,955,522)
		P	SG		(1,847,574)	(481,669)	(2,240,837)	(584,194)
		P	SE		(38,978,097)	(9,771,082)	515,386	129,198
		LABOR	SO		(139,330,481)	(37,860,386)	(20,243,135)	(5,500,684)
		GP	GPS		(8,504,333)	(2,310,889)	(8,540,637)	(2,320,754)
		PTD	SNP		(761,564)	(194,949)	(690,567)	(176,775)
		P	TROJD		-	-	-	-
		P	SG		-	-	-	-
		P	SG		-	-	-	-
		P	SG		-	-	-	-
				B19	(297,197,093)	(54,286,593)	(144,299,760)	(14,408,731)
Total Accum Deferred Income Tax				**B19**	**(2,565,819,019)**	**(623,521,952)**	**(2,702,858,647)**	**(643,480,187)**
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)	(50,351)	(175,594)	(45,778)
Total Accumulated ITC				**B19**	**(2,245,487)**	**(50,351)**	**(2,339,440)**	**(45,778)**
Total Rate Base Deductions					**(4,942,069,023)**	**(1,141,563,501)**	**(4,847,348,531)**	**(1,081,579,791)**
108SP	Steam Prod Plant Accumulated Depr							
		P	S		(9,098,547)	-	(9,098,547)	-
		P	SG		(749,221,847)	(195,324,698)	(749,221,847)	(195,324,698)
		P	SG		(719,880,716)	(187,675,365)	(719,880,716)	(187,675,365)
		P	SG		(1,901,219,938)	(495,654,540)	(3,397,616,381)	(885,770,211)
		P	SG		-	-	-	-
		P	SG		-	-	-	-
				B17	(3,379,421,048)	(878,654,603)	(4,875,817,492)	(1,268,770,274)
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)	(44,151,776)	(169,356,335)	(44,151,776)
		P	SG		(31,496,322)	(8,211,199)	(31,496,322)	(8,211,199)
		P	SG		(233,526,380)	(60,881,126)	(263,222,804)	(68,623,085)
		P	SG		(62,385,722)	(16,264,171)	(74,487,011)	(19,419,019)
		p	SG		-	-	-	-
				B17	(494,660,295)	(129,508,272)	(536,458,008)	(140,405,079)
108OP	Other Production Plant - Accum Depr							
		P	S		(4,783)	-	(183,200,250)	(183,195,467)
		P	SG		-	-	-	-
		P	SG		401,424,897	104,652,844	202,224,324	52,720,573
		P	SG		(482,707,852)	(125,843,588)	(570,089,603)	(148,624,309)
		P	SG		(43,837,829)	(11,428,672)	(43,837,829)	(11,428,672)
				B17	(125,125,568)	(32,619,417)	(594,903,358)	(290,527,875)

	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
2329	108EP	Experimental Plant - Accum Depr							
2330			P	SG		-	-	-	-
2331			P	SG		-	-	-	-
2332						-	-	-	-
2333									
2334	**Total Production Plant Accum Depreciation**				**B17**	**(3,999,206,912)**	**(1,040,782,292)**	**(6,007,178,858)**	**(1,699,703,228)**
2335									
2336	Summary of Prod Plant Depreciation by Factor								
2337			S			(6,998,866)	-	(190,194,333)	(183,195,467)
2338			DGP			-	-	-	-
2339			DGU			-	-	-	-
2340			SG			(3,992,208,046)	(1,040,782,292)	(5,816,984,525)	(1,516,507,761)
2341			SSGCH			-	-	-	-
2342			SSGCT			-	-	-	-
2343	Total of Prod Plant Depreciation by Factor					(3,999,206,912)	(1,040,782,292)	(6,007,178,858)	(1,699,703,228)
2344									
2345									
2346	108TP	Transmission Plant Accumulated Depr							
2347			T	SG		(353,157,214)	(92,069,293)	(353,157,214)	(92,069,293)
2348			T	SG		(426,788,101)	(111,265,118)	(426,788,101)	(111,265,118)
2349			T	SG		(1,221,447,907)	(318,435,647)	(1,394,500,313)	(363,551,001)
2350	**Total Trans Plant Accum Depreciation**				**B17**	**(2,001,393,221)**	**(521,770,058)**	**(2,174,445,627)**	**(566,885,412)**
2351	108360	Land and Land Rights							
2352			DPW	S		(10,029,714)	(2,430,506)	(11,725,368)	(2,747,792)
2353					B17	(10,029,714)	(2,430,506)	(11,725,368)	(2,747,792)
2354									
2355	108361	Structures and Improvements							
2356			DPW	S		(33,171,627)	(9,015,640)	(36,385,910)	(9,617,086)
2357					B17	(33,171,627)	(9,015,640)	(36,385,910)	(9,617,086)
2358									
2359	108362	Station Equipment							
2360			DPW	S		(354,040,121)	(101,151,751)	(380,710,272)	(106,142,180)
2361					B17	(354,040,121)	(101,151,751)	(380,710,272)	(106,142,180)
2362									
2363	108363	Storage Battery Equipment							
2364			DPW	S		-	-	-	-
2365					B17	-	-	-	-
2366									
2367	108364	Poles, Towers & Fixtures							
2368			DPW	S		(676,436,873)	(255,299,196)	(711,267,917)	(261,797,228)
2369					B17	(676,436,873)	(255,299,196)	(711,267,917)	(261,797,228)
2370									
2371	108365	Overhead Conductors							
2372			DPW	S		(349,174,705)	(138,403,566)	(371,107,699)	(142,507,594)
2373					B17	(349,174,705)	(138,403,566)	(371,107,699)	(142,507,594)
2374									
2375	108366	Underground Conduit							
2376			DPW	S		(179,429,394)	(48,957,173)	(190,311,061)	(50,993,314)
2377					B17	(179,429,394)	(48,957,173)	(190,311,061)	(50,993,314)
2378									
2379	108367	Underground Conductors							
2380			DPW	S		(380,517,399)	(96,545,872)	(405,902,124)	(101,295,777)
2381					B17	(380,517,399)	(96,545,872)	(405,902,124)	(101,295,777)
2382									
2383	108368	Line Transformers							
2384			DPW	S		(604,818,198)	(252,937,731)	(643,242,258)	(260,127,513)
2385					B17	(604,818,198)	(252,937,731)	(643,242,258)	(260,127,513)
2386									
2387	108369	Services							
2388			DPW	S		(362,180,959)	(145,922,962)	(385,941,472)	(150,368,950)
2389					B17	(362,180,959)	(145,922,962)	(385,941,472)	(150,368,950)
2390									
2391	108370	Meters							
2392			DPW	S		(107,844,570)	(22,471,764)	(114,348,638)	(23,688,784)
2393					B17	(107,844,570)	(22,471,764)	(114,348,638)	(23,688,784)
2394									
2395									
2396									
2397	108371	Installations on Customers' Premises							
2398			DPW	S		(7,220,271)	(2,126,093)	(7,445,148)	(2,168,171)
2399					B17	(7,220,271)	(2,126,093)	(7,445,148)	(2,168,171)
2400									
2401	108372	Leased Property							
2402			DPW	S		-	-	-	-
2403					B17	-	-	-	-
2404									
2405	108373	Street Lights							
2406			DPW	S		(34,236,684)	(12,787,348)	(35,847,149)	(13,088,693)
2407					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)	(186,466)	(715,242)	(186,466)
		G-DGU	SG		(1,951,711)	(508,818)	(1,951,711)	(508,818)
		G-SG	SG		(127,433,166)	(33,222,262)	(138,970,814)	(36,230,166)
		CUST	CN		(7,270,206)	(2,253,032)	(6,909,506)	(2,141,251)
		PTD	SO		(116,526,662)	(31,663,885)	(126,079,770)	(34,259,759)
		P	SE		(1,538,215)	(385,602)	(1,494,391)	(374,616)
		G-SG	SG		(130,406)	(33,997)	(130,406)	(33,997)
		G-SG	SG		-	-	-	-
				B17	(533,156,539)	(166,847,234)	(580,368,628)	(182,294,103)
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)**	**(166,847,234)**	**(580,368,628)**	**(182,294,103)**
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)	(385,602)	(1,494,391)	(374,616)
	SO				(116,526,662)	(31,663,885)	(126,079,770)	(34,259,759)
	CN				(7,270,206)	(2,253,032)	(6,909,506)	(2,141,251)
	SG				(130,230,525)	(33,951,543)	(141,768,172)	(36,959,447)
	DEU				-	-	-	-
	SSGCT				-	-	-	-
	SSGCH				-	-	-	-
	Remove Capital Leases				-	-	-	-
Total General Depreciation by Factor					(533,156,539)	(166,847,234)	(580,368,628)	(182,294,103)
Total Accum Depreciation - Plant In Service				**B17**	**(9,626,761,743)**	**(2,815,387,372)**	**(12,050,132,685)**	**(3,571,364,011)**

	2020 PROTOCOL Year End FERC ACCT	DESCRIP	BUS FUNC	FACTOR	Ref	JUNE 2021 UNADJUSTED RESULTS TOTAL	OREGON	DECEMBER 2023 NORMALIZED RESULTS TOTAL	OREGON
2485	111SP	Accum Prov for Amort-Steam							
2486			P	SG		-	-	-	-
2487			P	SG		-	-	-	-
2488					B18	-	-	-	-
2489									
2490									
2491	111GP	Accum Prov for Amort-General							
2492			G-SITUS	S		(11,923,722)	(4,741,005)	(12,632,235)	(5,225,362)
2493			CUST	CN		-	-	-	-
2494			I-SG	SG		-	-	-	-
2495			PTD	SO		(1,174,857)	(319,245)	(1,337,295)	(363,384)
2496			P	SE		-	-	-	-
2497					B18	(13,098,578)	(5,060,250)	(13,969,530)	(5,588,746)
2498									
2499									
2500	111HP	Accum Prov for Amort-Hydro							
2501			P	SG		-	-	-	-
2502			P	SG		-	-	-	-
2503			P	SG		(3,139,235)	(818,409)	(3,606,778)	(940,299)
2504			P	SG		-	-	-	-
2505					B18	(3,139,235)	(818,409)	(3,606,778)	(940,299)
2506									
2507									
2508	111IP	Accum Prov for Amort-Intangible Plant							
2509			I-SITUS	S		30,478,582	(129,177)	30,343,931	(140,175)
2510			I-DGP	SG		-	-	-	-
2511			I-DGU	SG		(397,058)	(103,514)	(397,058)	(103,514)
2512			P	SE		(1,897)	(476)	84,709	21,235
2513			I-SG	SG		(105,977,548)	(27,628,709)	(115,585,895)	(30,133,638)
2514			I-SG	SG		(114,544,697)	(29,862,194)	(118,482,024)	(30,888,669)
2515			I-SG	SG		(5,755,401)	(1,500,453)	(5,961,962)	(1,554,304)
2516			CUST	CN		(162,639,670)	(50,401,918)	(182,729,117)	(56,627,623)
2517			P	SG		-	-	-	-
2518			P	SG		-	-	-	-
2519			PTD	SO		(316,598,295)	(86,029,514)	(339,134,793)	(92,153,375)
2520					B18	(675,435,985)	(195,655,955)	(731,862,209)	(211,580,064)
2521	111IP	Less Non-Regulated Plant							
2522			NUTIL	OTH		-	-	-	-
2523						(675,435,985)	(195,655,955)	(731,862,209)	(211,580,064)
2524									
2525	111390	Accum Amtr - Capital Lease							
2526			G-SITUS	S		-	-	-	-
2527			P	SG		-	-	-	-
2528			PTD	SO		-	-	-	-
2529					B9	-	-	-	-
2530									
2531		Remove Capital Lease Amtr				-	-	-	-
2532									
2533	**Total Accum Provision for Amortization**				**B18**	**(691,673,798)**	**(201,534,614)**	**(749,438,517)**	**(218,109,109)**
2534									
2535									
2536									
2537									
2538	Summary of Amortization by Factor								
2539		S				18,554,860	(4,870,181)	17,711,696	(5,365,536)
2540		DGP				-	-	-	-
2541		DGU				-	-	-	-
2542		SE				(1,897)	(476)	84,709	21,235
2543		SO				(317,773,151)	(86,348,759)	(340,472,088)	(92,516,759)
2544		CN				(162,639,670)	(50,401,918)	(182,729,117)	(56,627,623)
2545		SSGCT				-	-	-	-
2546		SSGCH				-	-	-	-
2547		SG				(229,813,940)	(59,913,280)	(244,033,718)	(63,620,425)
2548		Less Capital Lease				-	-	-	-
2549	Total Provision For Amortization by Factor					(691,673,798)	(201,534,614)	(749,438,517)	(218,109,109)

Tab 1 - Retclsc

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 Pro Forma Revenue
3.2 REC Revenue
3.3 Wheeling Revenue
3.4 Ancillary Revenue
3.5 Fly Ash Revenue

Pacificorp
Oregon General Rate Case - December 2023
Tab 3 Adjustment Summary

		Total Adjustments	3.1 Pro Forma Revenue	3.2 REC Revenue	3.3 Wheeling Revenue	3.4 Ancillary Revenue	3.5 Fly Ash Revenue
1	Operating Revenues:						
2	General Business Revenues	(61,204,592)	(61,204,592)	-	-	-	-
3	Interdepartmental	-	-	-	-	-	-
4	Special Sales	-	-	-	-	-	-
5	Other Operating Revenues	4,704,600	-	(1,641,065)	8,265,447	(2,748,201)	828,419
6	Total Operating Revenues	(56,499,992)	(61,204,592)	(1,641,065)	8,265,447	(2,748,201)	828,419
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	(11,325,777)	(12,268,844)	(328,962)	1,656,860	(550,894)	166,062
26	Income Taxes - State	(2,564,975)	(2,778,553)	(74,501)	375,233	(124,762)	37,608
27	Income Taxes - Def Net	-	-	-	-	-	-
28	Investment Tax Credit Adj.	-	-	-	-	-	-
29	Misc Revenue & Expense	-	-	-	-	-	-
30							
31	Total Operating Expenses:	(13,890,752)	(15,047,397)	(403,462)	2,032,094	(675,656)	203,670
32							
33	Operating Rev For Return:	(42,609,240)	(46,157,195)	(1,237,602)	6,233,353	(2,072,544)	624,749
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	(131,295)	(142,228)	(3,814)	19,207	(6,386)	1,925
45	Weatherization Loans	-	-	-	-	-	-
46	Misc Rate Base	-	-	-	-	-	-
47							
48	Total Electric Plant:	(131,295)	(142,228)	(3,814)	19,207	(6,386)	1,925
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:	(131,295)	(142,228)	(3,814)	19,207	(6,386)	1,925
62							
63	Return on Rate Base	-0.891%	-0.965%	-0.026%	0.130%	-0.043%	0.013%
64							
65	Return on Equity	-1.706%	-1.848%	-0.050%	0.250%	-0.083%	0.025%
66							
67	TAX CALCULATION:						
68	Operating Revenue	(56,499,992)	(61,204,592)	(1,641,065)	8,265,447	(2,748,201)	828,419
69	Other Deductions		-	-	-	-	-
70	Interest (AFUDC)	-	-	-	-	-	-
71	Interest	(2,745)	(2,974)	(80)	402	(134)	40
72	Schedule "M" Additions	-	-	-	-	-	-
73	Schedule "M" Deductions	-	-	-	-	-	-
74	Income Before Tax	(56,497,246)	(61,201,618)	(1,640,985)	8,265,045	(2,748,067)	828,379
75							
76	State Income Taxes	(2,564,975)	(2,778,553)	(74,501)	375,233	(124,762)	37,608
77	Taxable Income	(53,932,271)	(58,423,065)	(1,566,484)	7,889,812	(2,623,305)	790,771
78							
79	Federal Income Taxes + Other	(11,325,777)	(12,268,844)	(328,962)	1,656,860	(550,894)	166,062
	APPROXIMATE PRICE CHANGE	58,398,993	63,260,742	1,695,882	(8,541,539)	2,839,999	(856,091)

PacifiCorp
Oregon General Rate Case - December 2023
Pro Forma Revenues

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Revenue:							
Residential	440	3	(45,321,380)	OR	Situs	(45,321,380)	3.1.1
Commercial	442	3	(5,691,236)	OR	Situs	(5,691,236)	3.1.1
Industrial[1]	442	3	(8,680,067)	OR	Situs	(8,680,067)	3.1.1
Public St. & Hwy	444	3	(1,511,908)	OR	Situs	(1,511,908)	3.1.1
Total			(61,204,592)			(61,204,592)	3.1.1

[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 shows a breakout between the TAM and general rate case revenues.

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	($19,894,626)	$628,693,569	($15,172,332)	$613,521,236	**($45,321,380)**
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	($19,580,460)	$461,991,194	$29,487,544	$491,478,738	**($5,691,236)**
Industrial	$118,599,710	($2,417,253)	$116,182,457	($3,459,754)	$112,722,703	$4,832,059	$0	$117,554,763	($2,575,981)	$114,978,782	($11,348,317)	$103,630,464	**($12,551,993)**
Irrigation	$30,442,034	($104,487)	$30,337,548	($191,256)	$30,146,292	$2,401,471	($1,379,464)	$31,168,299	($586,084)	$30,582,215	$3,627,258	$34,209,473	**$3,871,925**
Public St & Hwy	$5,982,047	($175,520)	$5,806,526	($11,596)	$5,794,930	($1,206,366)	$0	$4,588,564	($170,732)	$4,417,833	($123,215)	$4,294,618	**($1,511,908)**
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	($42,807,883)	$1,240,663,593	$6,470,938	$1,247,134,531	**($61,204,592)**
Source / Formula	305 Report			Ref. 3.1.8 - B	C + D	Ref. 3.1.9	Ref. 3.1.9	E + F + G	Ref. 3.1.9	H + I	Ref. 3.1.9	J + K	L - C **To. 3.1**

[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
Adjustment to MWhs
Historical 12 Months Ended June 2021; Forecast 12 Months Ended December 2023

	A	B	C	D	E	F	G	H
	Total MWhs	Normalizing Adjustments MWhs[1]	Temperature Adjustments MWhs	Type 1 Adjusted MWhs	Type 2 Adjustments MWhs[2]	Total Oregon Adjusted Actual MWhs	Type 3 Adjustment MWhs[3]	Total Oregon Forecast MWhs
Residential	5,917,093	(1,093)	(14,000)	5,902,000	(57)	5,901,942	(121,109)	5,780,833
Commercial	5,623,745	558	(53,091)	5,571,212	82,869	5,654,081	667,468	6,321,549
Industrial	1,563,748	3,480	0	1,567,229	33,800	1,601,028	(135,519)	1,465,509
Irrigation	313,870	4,279	(14,953)	303,197	120	303,317	30,399	333,716
Public St & Hwy	38,510	(1,794)	0	36,716	(1,057)	35,659	337	35,996
Total Oregon	13,456,967	5,431	(82,044)	13,380,353	115,675	13,496,028	441,575	13,937,602
Source / Formula	305 Report	Table 2	Table 2	A + B + C	Table 2	D + E	Table 2	F + G

[1] Out of Period adjustment.
[2] Adjustment made to reconcile booked MWh with blocking MWh. Includes adjustment to incorporate direct access MWh.
[3] Adjustment from actual to forecast.

PacifiCorp PAGE 3.1.3
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	263,565	$5,202,762
47	29,109	$530,243
48	3,555,464	$67,892,212
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	$288,535,772

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	$6,408,529
Percentage Change	2.5%	2.3%

PacifiCorp
Oregon General Rate Case - December 2023
Revenue split between TAM and GRC Proforma Revenue

Total Revenue - 2023	TAM/ NPC	NON-TAM / NON NPC
$1,247,134,531	$288,535,772	$958,598,759
Ref 3.1.1	Ref 3.1.3	

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
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
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
	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
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	16	7,997	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
AGA	0			0			0	0
Total Irrigation	**7,987**	**16**	**8,003**	**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)
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**	**15,051**	**646,174**	**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				
	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
Residential							
15	(22,973)	1,943,513	(111,996)	1,831,517	$296,609	$12,697	$309,306
4	26,448	5,755,783,167	(121,926,689)	5,633,856,479	$589,286,974	$49,490,861	$638,777,835
23	(60,735)	98,442,237	(2,352,104)	96,090,133	$12,460,168	$823,622	$13,283,791
28	(26)	44,981,453	4,073,407	49,054,860	$3,643,986	$278,862	$3,922,848
BPA Balancing Account		0		0	($192,823)	$192,823	$0
Solar Feed-In Revenue		0		0	$2,229,585	($2,229,585)	$0
Gain on Sale of Asset		0		0	$17,372	($17,372)	$0
Revenue Accounting Adjustment		0		0	($2,570,998)	$2,570,998	$0
Customer Bill Credits		0		0	($165,055)	$165,055	$0
Communtiy Solar Revenue					$234,155	($234,155)	$0
Revenue Adjustment - I&D Reserve		0		0	($723,515)	$723,515	$0
DSM		0		0	$20,507,206	($20,507,206)	$0
Blue Sky		0		0	$961,756	($961,756)	$0
Income Tax Deferral Adjustments		0		0	$18,777,988	($18,777,988)	$0
Unbilled		792,000	(792,000)	0	($1,485,000)	$0	($1,485,000)
AGA		0		0	$5,168	$0	$5,168
Total Residential	**(57,286)**	**5,901,942,370**	**(121,109,381)**	**5,780,832,989**	**$643,283,576**	**$11,530,371**	**$654,813,947**
Commercial							
15	(86,642)	6,233,732	(108,072)	6,125,660	$834,201	$19,063	$853,265
23	404,577	1,055,955,485	(32,167,089)	1,023,788,396	$116,350,093	$1,870,811	$118,220,904
28	5,398,837	1,873,004,303	(7,813,105)	1,865,191,198	$166,712,986	$2,428,563	$169,141,550
30	46,010,169	1,061,285,614	53,675,458	1,114,961,072	$81,751,815	$1,208,280	$82,960,094
47	0	26,505,750	588,744	27,094,494	$3,198,340	$18,006	$3,216,346
48	31,141,972	1,489,328,572	793,918,184	2,283,246,756	$97,356,107	$1,429,426	$98,785,533
54	0	1,310,533	(169,291)	1,141,242	$124,979	$1,669	$126,648
BPA Balancing Account		0		0	$3,623	($3,623)	$0
Solar Feed-In Revenue		0		0	$1,982,204	($1,982,204)	$0
Gain on Sale of Asset		0		0	$16,222	($16,222)	$0
Revenue Accounting Adjustment		0		0	$1,014,355	($1,014,355)	$0
Customer Bill Credits		0		0	($20,212)	$20,212	$0
Communtiy Solar Revenue					$169,681	($169,681)	$0
Other Customer Retail Rev					$19,898	($19,898)	$0
Revenue Adjustment - I&D Reserve		0		0	($550,246)	$550,246	$0
DSM		0		0	$12,360,668	($12,360,668)	$0
Blue Sky		0		0	$1,059,754	($1,059,754)	$0
Income Tax Deferral Adjustments		0		0	$17,786,169	($17,786,169)	$0
Unbilled		140,457,000	(140,457,000)	0	$9,873,000	$0	$9,873,000
AGA		0		0	$3,232,134	$0	$3,232,134
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**
Industrial							
15	158	244,119	3,427	247,546	$29,129	$517	$29,646
23	(24)	17,990,621	(1,457,448)	16,533,173	$1,993,674	$28,628	$2,022,303
28	(34)	81,595,023	(3,570,368)	78,024,655	$7,815,407	$86,126	$7,901,533
30	24	176,738,750	(10,118,492)	166,620,258	$15,624,654	$136,881	$15,761,534
47	0	2,230,154	(216,000)	2,014,154	$898,001	($2,869)	$895,133
	33,799,589	1,307,430,819	(105,361,574)	1,202,069,245	$83,696,157	$913,759	$84,609,917
BPA Balancing Account		0		0	$51	($51)	$0
Solar Feed-In Revenue		0		0	$554,274	($554,274)	$0
Gain on Sale of Asset		0		0	$4,791	($4,791)	$0
Revenue Accounting Adjustment		0		0	($489,343)	$489,343	$0
Customer Bill Credits		0		0	($3,613)	$3,613	$0
Communtiy Solar Revenue					$47,336	($47,336)	$0
Revenue Adjustment - I&D Reserve		0		0	($179,951)	$179,951	$0
DSM		0		0	$949,796	($949,796)	$0
Blue Sky		0		0	$581,738	($581,738)	$0
Income Tax Deferral Adjustments		0		0	$5,574,970	($5,574,970)	$0
Unbilled		14,799,000	(14,799,000)	0	$1,390,000	$0	$1,390,000
AGA		0		0	$112,639	$0	$112,639
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**
Irrigation							
41	120,790	224,362,899	39,202,171	263,565,070	$22,908,886	$1,456,716	$24,365,602
23	(629)	4,255	(1,232)	3,023	$663	$4	$667
48	0	58,920,615	11,227,218	70,147,833	$3,864,294	$346,646	$4,210,940
BPA Balancing Account		0		0	$76,703	($76,703)	$0
BPA Adjustment		0		0	$272,963	($272,963)	$0
Demand Charge Accrual		0		0	$193,000	$0	$193,000
Solar Feed-In Revenue		0		0	$72,078	($72,078)	$0
Gain on Sale of Asset		0		0	$116	($116)	$0
Revenue Accounting Adjustment		0		0	($75,223)	$75,223	$0
Communtiy Solar Revenue		0		0	$8,305	($8,305)	$0
Revenue Adjustment - I&D Reserve		0		0	($31,031)	$31,031	$0
DSM		0		0	$773,574	($773,574)	$0
Blue Sky		0		0	$518	($518)	$0
Income Tax Deferral Adjustments		0		0	$1,001,106	($1,001,106)	$0
Unbilled		20,029,000	(20,029,000)	0	$1,205,000	$0	$1,205,000
AGA		0		0	$171,083	$0	$171,083
Total Irrigation	**120,161**	**303,316,769**	**30,399,157**	**333,715,926**	**$30,442,034**	**($295,742)**	**$30,146,292**
Lighting							
15	(586)	54,552	679	55,231	$9,118	$166	$9,284
23	(3)	596,323	(325)	595,998	$139,943	$502	$140,446
50	(3,494,666)	0		0	$453,624	$13,909	$467,534
51	2,579,332	24,436,047	(543,468)	23,892,579	$4,287,037	$54,508	$4,341,544
52	(135,913)	0		0	$20,380	$628	$21,008
53	(4,993)	10,736,096	715,684	11,451,780	$843,364	$12,750	$856,115
Solar Feed-In Revenue		0		0	$12,836	($12,836)	$0
Gain on Sale of Asset		0		0	$834	($834)	$0
Revenue Accounting Adjustment		0		0	($12,537)	$12,537	$0
Communtiy Solar Revenue		0		0	$894	($894)	$0
DSM		0		0	$137,330	($137,330)	$0
Income Tax Deferral Adjustments		0		0	$130,222	($130,222)	$0
Unbilled		(164,000)	164,000	0	($41,000)	$0	($41,000)
AGA		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**
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**

PacifiCorp
Oregon General Rate Case - December 2023
Historical 12 Months Ended June 2021; Foreca
Revenue, kWh and Customer Adjustments

	REVENUES						
	Type 1			Type 2		Type 3	
	Normalizing Adjustments $	Temperature Adjustment $	Total Type 1 Adjusted Revenues	Type 2 Adjustments $	Total Type 2 Adjusted Revenues	Type 3 Adjustments $	Total Adjusted Revenues
Residential							
15	($35,347)		$273,959	($19,955)	$254,004	($266)	$253,738
4	($4,506,494)	($1,324,480)	$632,946,861	($19,533,743)	$613,413,118	($16,690,537)	$596,722,581
23	($211,229)	($35,315)	$13,037,246	($113,577)	$12,923,669	($230,770)	$12,692,899
28	($112,887)	$0	$3,809,961	($227,351)	$3,582,610	$264,241	$3,846,851
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	$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		($1,485,000)		($1,485,000)	$1,485,000	$0
AGA	$0		$5,168		$5,168		$5,168
Total Residential	**($4,865,957)**	**($1,359,796)**	**$648,588,195**	**($19,894,626)**	**$628,693,569**	**($15,172,332)**	**$613,521,236**
Commercial							
15	($102,234)		$751,031	($148,662)	$602,369	$30,554	$632,923
23	($2,276,824)	($848,240)	$115,095,840	($1,024,198)	$114,071,642	($4,271,707)	$109,799,935
28	($4,724,774)	($1,073,910)	$163,342,866	($7,724,076)	$155,618,790	($2,644,988)	$152,973,802
30	($1,769,929)	($507,841)	$80,682,324	($3,010,104)	$77,672,220	$2,522,018	$80,194,238
47	$47,993		$3,264,339	($124,335)	$3,140,004	$41,109	$3,181,113
48	$7,193,549	($750,127)	$105,228,955	($7,540,973)	$97,687,982	$43,694,976	$141,382,958
54	($25,482)		$101,166	($8,113)	$93,053	($11,418)	$81,635
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	$0		$0		$0		$0
Other Customer Retail Rev	$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		$9,873,000		$9,873,000	($9,873,000)	$0
AGA	$0		$3,232,134		$3,232,134		$3,232,134
Total Commercial	**($1,657,701)**	**($3,180,119)**	**$481,571,654**	**($19,580,460)**	**$461,991,194**	**$29,487,544**	**$491,478,738**
Industrial							
15	($3,783)		$25,863	($6,543)	$19,320	$1,842	$21,162
23	($36,663)	$0	$1,985,640	($16,168)	$1,969,472	($157,753)	$1,811,719
28	($208,323)	$0	$7,693,210	($384,882)	$7,308,328	($396,887)	$6,911,441
30	($303,856)		$15,457,678	($448,839)	$15,008,839	($1,006,476)	$14,002,363
47	$9,140		$904,273	($27,126)	$877,147	($84,391)	$792,756
	$5,375,544		$89,985,461	($1,692,424)	$88,293,037	($8,314,652)	$79,978,385
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	$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		$1,390,000		$1,390,000	($1,390,000)	$0
AGA	$0		$112,639		$112,639		$112,639
Total Industrial	**$4,832,059**	**$0**	**$117,554,763**	**($2,575,981)**	**$114,978,782**	**($11,348,317)**	**$103,630,464**
Irrigation							
41	$2,281,274	($1,283,779)	$25,363,097	($295,597)	$25,067,500	$4,126,316	$29,193,816
23	$204	$0	$871	($230)	$641	($129)	$512
48	$312,993	($95,685)	$4,428,248	($290,257)	$4,137,991	$706,071	$4,844,062
BPA Balancing Account	$0		$0		$0		$0
BPA Adjustment	$0		$0		$0		$0
Demand Charge Accrual	($193,000)		$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		$1,205,000		$1,205,000	($1,205,000)	$0
AGA	$0		$171,083		$171,083		$171,083
Total Irrigation	**$2,401,471**	**($1,379,464)**	**$31,168,299**	**($586,084)**	**$30,582,215**	**$3,627,258**	**$34,209,473**
Lighting							
15	($934)		$8,350	($1,610)	$6,740	$482	$7,222
23	($1,270)		$139,176	$257	$139,433	($6,354)	$133,079
50	($76,288)		$391,246	($391,246)	$0	$0	$0
51	($916,723)		$3,424,821	$142,062	$3,566,883	($69,325)	$3,497,558
52	($3,044)		$17,964	($17,964)	$0	$0	$0
53	($208,107)		$648,008	$97,769	$745,777	($89,017)	$656,760
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		$0
Unbilled	$0		($41,000)		($41,000)	$41,000	$0
AGA	$0		$0		$0		$0
Total Lighting	**($1,206,366)**	**$0**	**$4,588,564**	**($170,732)**	**$4,417,833**	**($123,215)**	**$4,294,618**
TOTAL COMPANY	**($496,493)**	**($5,919,378)**	**$1,283,471,475**	**($42,807,883)**	**$1,240,663,593**	**$6,470,938**	**$1,247,134,531**

Exhibit PAC/1002
Cheung/57

PacifiCorp
Oregon General Rate Case - December 2023
Pro Forma Revenue
Historical 12 Months Ended June 2021; Forecast 12 Months Ended December 2023
Revenue Adjustments

	305 Booked Revenues	Remove Accounting Adjustments	Remove Tariff Riders: 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
Communtiy 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
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
Communtiy 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
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
	$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
Communtiy 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
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
Communtiy 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
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
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)**

PacifiCorp
Oregon General Rate Case - December 2023
Pro Forma Revenue
Historical 12 Months Ended June 2021; Forecas
Revenue Adjustments

	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
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**	**($19,894,626)**	**($19,894,626)**	**$628,693,569**	**($6,893,612)**	**($8,278,720)**	**($15,172,332)**	**$613,521,236**
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
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**	**($19,580,460)**	**($19,580,460)**	**$461,991,194**	**($5,927,067)**	**$35,414,611**	**$29,487,544**	**$491,478,738**
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
	$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
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**	**($2,575,981)**	**($2,575,981)**	**$114,978,782**	**($1,672,083)**	**($9,676,235)**	**($11,348,317)**	**$103,630,464**
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)	$4,361,899	$4,126,316	$29,193,816
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)	$768,619	$706,071	$4,844,062
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
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**	**($586,084)**	**($586,084)**	**$30,582,215**	**($298,136)**	**$3,925,394**	**$3,627,258**	**$34,209,473**
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
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**	**($170,732)**	**($170,732)**	**$4,417,833**	**($120,143)**	**($3,071)**	**($123,215)**	**$4,294,618**
TOTAL COMPANY	**$1,289,887,347**	**($193,000)**	**($512,137)**	**$208,644**	**($496,493)**	**($5,919,378)**	**$1,283,471,475**	**($42,807,883)**	**($42,807,883)**	**$1,240,663,593**	**($14,911,041)**	**$21,381,979**	**$6,470,938**	**$1,247,134,531**

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	26.070%	(2,355,140)	3.2.1
June 2021 REC Deferrals	456	1	2,739,416	SG	26.070%	714,175	3.2.1
June 2021 Leaning Juniper Indemnity	456	1	(385)	SG	26.070%	(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.

PacifiCorp
Oregon General Rate Case - December 2023
REC Revenue
Actuals as Booked

Posting Date	Fin Accrual	Fin Reversal	Back Office Actual	SAP Total
FERC Acct (Ref B1)	4562700	4562700	4562700	
SAP Acct	301944	301944	301945	
July-20	(56,390)	83,750	(90,140)	(62,780)
August-20	(50,000)	56,390	(50,000)	(43,610)
September-20	(50,000)	50,000	(50,000)	(50,000)
October-20	(666,500)	50,000	(60,596)	(677,096)
November-20	(6,170,733)	4,085,633	(666,500)	(2,751,600)
December-20	(293,750)	2,751,600	(2,751,600)	(293,750)
January-21	(1,570,611)	293,750	(293,750)	(1,570,611)
February-21	(50,000)	1,570,611	(1,570,611)	(50,000)
March-21	(100,750)	50,000	(199,000)	(249,750)
April-21	(2,421,588)	100,750	(418,435)	(2,739,273)
May-21	(261,194)	2,421,588	(2,421,587)	(261,194)
June-21	(233,500)	261,194	(311,819)	(284,125)
12 ME June 2021 Total	(11,925,016)	11,775,266	(8,884,038)	**(9,033,788)**
				Ref 3.2

REC Deferrals Included in Unadjusted Results:

FERC Account	4562700	
Amount 12 ME June 2021	**2,739,416**	**Ref 3.2**

Leaning Juniper indemnity revenue included in Unadjusted Results:

FERC Account	4562700	
Amount 12 ME June 2021	**(385)**	**Ref 3.2**

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	26.070%	372,218	3.3.1
Other Electric Revenues	456	2	(480,136)	SG	26.070%	(125,173)	3.3.1
Other Electric Revenues	456	3	30,756,795	SG	26.070%	8,018,402	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.

PacifiCorp
Oregon General Rate Case - December 2023
Wheeling Revenue

PAGE 3.3.1

Customer	Total
3 Phases Renewables, Inc.	(5,267)
Airport Solar LLC	(2,069,560)
Arizona Electric Power Co-op	(44)
Avangrid Renewables, LLC	(6,075,505)
BASIN ELECTRIC POWER COOPERATIVE	(765,890)
BLACK HILLS POWER & LIGHT COMPANY	(3,198,151)
BONNEVILLE POWER ADMINISTRATION	(21,261,631)
Brookfield Energy Marketing L.P.	(1,091,852)
Calpine Energy Solutions, LLC	(535,370)
City of Roseville	(1,562,545)
Clatskanie PUD	(505,826)
Colorado Electric Utility Co.	(11,742)
Constellation NewEnergy, Inc.	(48,188)
CONSTELLATION POWER SOURCE, INC.	(1,832,842)
CP Energy Marketing	(11,215)
DESERET GENERATION & TRANS. CO-OP.	(5,998,739)
Dynasty Power	(2,058)
Eagle Energy Partners I LP	(367,177)
EDP Renewables North American LLC	(178,149)
Enel Trading North America	(43,216)
Energy Keepers, Inc.	(235,207)
Eugene Water & Electric Board	(470)
Evergreen BioPower	(374,092)
FALL RIVER RURAL ELECTRIC COOPERATI	(151,308)
Falls Creek H.P., LP	(154,706)
Guzman Energy	(734,723)
Idaho Power Co. Balancing Ops	(909,216)
Imperial Irrigation District	(151,038)
Intermountain Renewable(Cyrq Enrgy)	(415,535)
LH Garrett	(406,288)
Macquarie Energy LLC	(437,870)
MAG Energy Solutions Inc.	(96,911)
Mercuria Energy	(280,451)
Moon Lake Electric Association	(20,424)
MORGAN STANLEY CAPITAL	(6,000,024)
Navajo Tribal Utility Authority	(85,361)
NextEra Energy Resources, LLC	(3,846,724)
Obsidian Renewables, LLC	(7,000)
PACIFIC GAS & ELECTRIC COMPANY	(54,519)
PACIFICORP	-
PORTLAND GENERAL ELECTRIC COMPANY	(4)
POWEREX	(22,953,818)
RAINBOW ENERGY MARKETING CORPORATIO	(1,067,691)
Sacramento Municipal Utility Dist	(639,955)
Salt River Project	(866,969)
Shell Energy NA (Coral Power)	(5,034,768)
SIERRA PACIFIC POWER COMPANY	(33,146)
So. Cal Public Power Authority	(47,733)
Southern California Edison Company	(3,930,368)
State of South Dakota	(134,729)
TEC Energy	(1,145)
Tenaska Power Services Company	(519,215)
The Energy Authority	(138,922)
TRANSALTA ENERGY MARKETING CORP.	(1,333,310)
TRI-STATE GEN. & TRANS. ASSOCIATION	(626,607)
U.S. Bureau of Reclamation	(64,348)
UTAH ASSOCIATED MUNICIPAL POWER SYS	(19,470,100)
UTAH MUNICIPAL POWER AGENCY	(2,695,108)
Warm Springs Power Enterprises	(119,700)
WESTERN AREA POWER ADMIN. - UT	(3,243,301)
WESTERN AREA POWER ADMINISTRATION	(91,449)
Cowlitz Revenue	(185,531)
Accruals and Adjustments	(6,636,239)
Total	**(129,760,988)**
	Ref 3.3

Type	Adjustment	Amount
1	Remove refunds and other out of period adjustments*	(1,427,746)
2	BPA WEID Network Annualization*	(2,332)
2	BPA Green Springs Conversion to Network Service*	482,468
3	New Powerex Contracts 1016 and 1017*	(7,936,950)
3	EDP Renewable Contracts	(2,631,332)
3	Forecasted Price/Volume Increase Network	(20,188,513)
	Incremental Adjustments	**(31,704,404)**
		Ref 3.3
	Accum Totals	**(161,465,392)**
		Ref 3.3

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	26.070%	(2,748,201)	3.4.1

Description of Adjustment:

This adjustment includes ancillary revenue contract changes that are included in the net power cost study.

PacifiCorp
Oregon General Rate Case - December 2023
Ancillary Services Revenue

Description	12 Months Ended June 2021	12 Months Ending December 2023	Incremental Change	FERC Acct	Factor	Ref
BPA Foote Creek 4 Ancillary Service	136,182	-	(136,182)	456	SG	
SCL Stateline Demand & Energy	10,405,301	-	(10,405,301)	456	SG	
	10,541,483	**-**	**(10,541,483)**			3.4

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	26.070%	828,419	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.

Tab 4 - Operation & Maintenance Expense

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 Miscellaneous General Expenses & Revenues	4.2 Wage & Employee Benefits Adjustment	4.3 Pension Related Non Service Expense	4.4 Remove Non-Recurring Entries	4.5 Insurance Expense	4.6 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	5,165,696	-	1,607,904	-	-	-	148,346
10 Nuclear Production	-	-	-	-	-	-	-
11 Hydro Production	(7,806,503)	-	338,845	-	(8,603,213)	-	-
12 Other Power Supply	2,779,918	(654)	609,267	-	-	-	824,755
13 Transmission	155,610	-	501,704	-	-	-	-
14 Distribution	28,356,724	-	2,789,657	-	-	-	-
15 Customer Accounting	1,470,447	(14,359)	555,165	-	-	-	-
16 Customer Service & Info	418,878	22,789	178,313	-	-	-	-
17 Sales	-	-	-	-	-	-	-
18 Administrative & General	(25,183,567)	347,261	815,733	609,110	-	(27,897,466)	-
19							
20 Total O&M Expenses	5,357,203	355,037	7,396,589	609,110	(8,603,213)	(27,897,466)	973,101
21		-	-	-	-	-	-
22 Depreciation	-	-	-	-	-	-	-
23 Amortization	-	-	-	-	-	-	-
24 Taxes Other Than Income	(1,473,948)	-	-	-	-	-	-
25 Income Taxes - Federal	1,450,480	262,240	(1,482,986)	(122,124)	1,724,909	7,488,960	(195,103)
26 Income Taxes - State	328,494	59,390	(335,855)	(27,658)	390,644	1,696,042	(44,185)
27 Income Taxes - Def Net	(2,473,765)	-	-	-	-	(2,473,765)	-
28 Investment Tax Credit Adj.	-	-	-	-	-	-	-
29 Misc Revenue & Expense	102,338	102,338	-	-	-	-	-
30							
31 Total Operating Expenses:	3,290,802	779,004	5,577,748	459,328	(6,487,660)	(21,186,229)	733,813
32							
33 Operating Rev For Return:	(1,524,183)	987,615	(5,577,748)	(459,328)	6,487,660	21,186,229	(733,813)
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	53,519	6,396	52,721	4,342	(61,321)	(176,870)	6,936
45 Weatherization Loans	-	-	-	-	-	-	-
46 Misc Rate Base	-	-	-	-	-	-	-
47							
48 Total Electric Plant:	53,519	6,396	52,721	4,342	(61,321)	(176,870)	6,936
49		-	-	-	-	-	-
50 Rate Base Deductions:		-	-	-	-	-	-
51 Accum Prov For Deprec	-	-	-	-	-	-	-
52 Accum Prov For Amort	-	-	-	-	-	-	-
53 Accum Def Income Tax	(9,430,521)	-	-	-	-	(9,430,521)	-
54 Unamortized ITC	-	-	-	-	-	-	-
55 Customer Adv For Const	-	-	-	-	-	-	-
56 Customer Service Deposits	-	-	-	-	-	-	-
57 Misc Rate Base Deductions	38,356,344	-	-	-	-	38,356,344	-
58							
59 Total Rate Base Deductions	28,925,824	-	-	-	-	28,925,824	-
60							
61 Total Rate Base:	28,979,343	6,396	52,721	4,342	(61,321)	28,748,953	6,936
62							
63 Return on Rate Base	-0.065%	0.021%	-0.117%	-0.010%	0.136%	0.407%	-0.015%
64							
65 Return on Equity	-0.125%	0.040%	-0.223%	-0.018%	0.260%	0.779%	-0.029%
66							
67 TAX CALCULATION:							
68 Operating Revenue	(2,218,974)	1,309,244	(7,396,589)	(609,110)	8,603,213	27,897,466	(973,101)
69 Other Deductions	-	-	-	-	-	-	-
70 Interest (AFUDC)	-	-	-	-	-	-	-
71 Interest	606,921	1,094	1,102	91	(1,282)	601,144	145
72 Schedule "M" Additions	10,061,436	-	-	-	-	10,061,436	-
73 Schedule "M" Deductions	-	-	-	-	-	-	-
74 Income Before Tax	7,235,540	1,308,151	(7,397,692)	(609,201)	8,604,495	37,357,758	(973,246)
75							
76 State Income Taxes	328,494	59,390	(335,855)	(27,658)	390,644	1,696,042	(44,185)
77 Taxable Income	6,907,046	1,248,761	(7,061,836)	(581,543)	8,213,851	35,661,716	(929,060)
78							
79 Federal Income Taxes + Other	1,450,480	262,240	(1,482,986)	(122,124)	1,724,909	7,488,960	(195,103)
APPROXIMATE PRICE CHANGE	4,983,679	(1,353,743)	7,650,024	629,981	(8,897,991)	(26,195,834)	1,006,443

Pacificorp
Oregon General Rate Case - December 202
Tab 4 Adjustment Summary

		4.7 Revenue Sensitive Items & Uncollectible Expense	4.8 Memberships and Subscriptions	4.9 Meals and Entertainment Adjustment	4.10 O&M Expense Escalation	4.11 Veg. & Wildfire Management O&M	4.12 Transmission Wheeling Facebook
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	-	-	(433)	3,409,878	-	-
10	Nuclear Production	-	-	-	-	-	-
11	Hydro Production	-	-	(579)	458,444	-	-
12	Other Power Supply	-	-	(4,347)	1,350,898	-	-
13	Transmission	-	-	(270)	593,817	296,925	(1,236,567)
14	Distribution	-	-	(8,751)	(482,130)	26,057,949	-
15	Customer Accounting	(274,522)	-	(260)	1,204,424	-	-
16	Customer Service & Info	-	-	(3,405)	221,181	-	-
17	Sales	-	-	-	-	-	-
18	Administrative & General	(227,655)	(146,082)	(2,625)	1,318,158	-	-
19							
20	Total O&M Expenses	(502,178)	(146,082)	(20,671)	8,074,669	26,354,874	(1,236,567)
21		-	-	-	-	-	-
22	Depreciation	-	-	-	-	-	-
23	Amortization	-	-	-	-	-	-
24	Taxes Other Than Income	(1,473,948)	-	-	-	-	-
25	Income Taxes - Federal	396,205	29,289	4,144	(1,618,938)	(5,284,044)	247,927
26	Income Taxes - State	89,729	6,633	939	(366,645)	(1,196,690)	56,149
27	Income Taxes - Def Net	-	-	-	-	-	-
28	Investment Tax Credit Adj.	-	-	-	-	-	-
29	Misc Revenue & Expense	-	-	-	-	-	-
30							
31	Total Operating Expenses:	(1,490,191)	(110,160)	(15,588)	6,089,087	19,874,141	(932,492)
32							
33	Operating Rev For Return:	1,490,191	110,160	15,588	(6,089,087)	(19,874,141)	932,492
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	(14,085)	(1,041)	(147)	57,554	187,850	(8,814)
45	Weatherization Loans	-	-	-	-	-	-
46	Misc Rate Base	-	-	-	-	-	-
47							
48	Total Electric Plant:	(14,085)	(1,041)	(147)	57,554	187,850	(8,814)
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:	(14,085)	(1,041)	(147)	57,554	187,850	(8,814)
62							
63	Return on Rate Base	0.031%	0.002%	0.000%	-0.127%	-0.413%	0.019%
64							
65	Return on Equity	0.059%	0.004%	0.001%	-0.242%	-0.791%	0.037%
66							
67	TAX CALCULATION:						
68	Operating Revenue	1,976,126	146,082	20,671	(8,074,669)	(26,354,874)	1,236,567
69	Other Deductions	-	-	-	-	-	-
70	Interest (AFUDC)	-	-	-	-	-	-
71	Interest	(295)	(22)	(3)	1,203	3,928	(184)
72	Schedule "M" Additions	-	-	-	-	-	-
73	Schedule "M" Deductions	-	-	-	-	-	-
74	Income Before Tax	1,976,420	146,104	20,674	(8,075,873)	(26,358,802)	1,236,751
75							
76	State Income Taxes	89,729	6,633	939	(366,645)	(1,196,690)	56,149
77	Taxable Income	1,886,691	139,470	19,735	(7,709,228)	(25,162,113)	1,180,603
78							
79	Federal Income Taxes + Other	396,205	29,289	4,144	(1,618,938)	(5,284,044)	247,927
	APPROXIMATE PRICE CHANGE	(2,062,074)	(151,053)	(21,374)	8,393,354	27,265,227	(1,279,281)

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	27.173%	609,109	
Gain on Property Sales	421	1	(1,947,042)	SG	26.070%	(507,601)	
Gain on Property Sales	421	1	830	OR	Situs	830	
Gain on Property Sales	421	1	(65,100)	UT	Situs	-	
			230,276			102,338	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	26.070%	(654)	
Administrative & General Salaries	920	1	-	SO	27.173%	-	
Office Supplies and Expenses	921	1	1,284,000	SO	27.173%	348,902	
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	27.173%	645	
Duplicate Charges	929	1	317	SO	27.173%	86	
Duplicate Booking Reversal	431	1	3,750	SNP	25.599%	960	
			1,284,821			355,996	4.1.1
Total Adjustments			3,281,716			2,224,954	

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.

PacifiCorp
Oregon General Rate Case - December 2023
Miscellaneous General Expense & Revenue

Description	FERC	Factor	Code	Adjustment	
FERC 421 - (Gain)/Loss on Sale of Utility Plant					
Gain on Property Sales	421	SO	421SO	2,241,588	
Gain on Property Sales	421	SG	421SG	(1,947,042)	
Gain on Property Sales	421	OR	421OR	830	
Gain on Property Sales	421	UT	421UT	(65,100)	
				230,276	**Ref 4.1**
Non-Regulated Flights					
Other Expenses	557	SG	557SG	(2,509)	
Office Supplies and Expenses	921	SO	921SO	(14,770)	
				(17,279)	
Regulatory Commission Expenses					
Remove transmission costs from Situs allocation	928	OR	928OR	(2,373)	
Assign transmission costs to system allocation	928	SO	928SO	2,373	
Removal of duplicated entry	431	SNP	431SNP	3,750	
				3,750	
Credit Facility Fee Adjustment					
Reallocate credit facility fees interest expense	921	SO	921SO	1,313,469	
FERC 909 - Informational & Instructional Advertising					
Blue Sky	909	CN	909CN	4,970	
Blue Sky	909	OR	909OR	9,072	
Blue Sky	903	OR	903OR	(14,359)	
Blue Sky	929	SO	929SO	317	
Giving Campagin	909	CN	909CN	(420)	
Remove system allocation	909	CN	909CN	(78,541)	
Remove Situs allocation	909	UT	909UT	(1,052)	
Add situs allocation	909	ID	909ID	1,052	
Add situs allocation	909	UT	909UT	12,132	
Add situs allocation	909	WA	909WA	10,746	
Add situs allocation	909	CA	909CA	19,017	
Add situs allocation	909	OR	909OR	36,647	
Total				(420)	
FERC 921 - Office Supplies & Expenses					
Expense removal	921	SO	921SO	(14,699)	
				(14,699)	
TOTAL MISC GENERAL EXPENSE REMOVED				**1,284,821**	**Ref. 4.1**

PacifiCorp
Oregon General Rate Case - December 2023
Miscellaneous General Expense & Revenue

Revenues that need to be included in results:

	Five-year Opt Out Amortization	Total	Account	Factor	
Residential		**-**	**440**	**OR**	**Ref 4.1**
Commercial & Industrial	1,766,619	**1,766,619**	**442**	**OR**	**Ref 4.1**
Street & Highway Lighting	-	**-**	**444**	**OR**	**Ref 4.1**
	1,766,619	**1,766,619**			

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	3,466,582	SG	26.070%	903,750	
Fuel Related-Non NPC	501	3	4,907	SE	25.068%	1,230	
Steam Maintenance	512	3	2,696,262	SG	26.070%	702,925	
Hydro Operations	535	3	671,585	SG-P	26.070%	175,085	
Hydro Operations	535	3	457,495	SG-U	26.070%	119,271	
Hydro Maintenance	545	3	139,850	SG-P	26.070%	36,459	
Hydro Maintenance	545	3	30,805	SG-U	26.070%	8,031	
Other Operations	548	3	550,440	SG	26.070%	143,502	
Other Operations	549	3	1,049	OR	Situs	1,049	
Other Maintenance	553	3	177,568	SG	26.070%	46,293	
Other Power Supply Expenses	557	3	1,604,981	SG	26.070%	418,424	
Other Power Supply Expenses	557	3	3,804	ID	Situs	-	
Transmission Operations	560	3	1,179,760	SG	26.070%	307,568	
Transmission Maintenance	571	3	744,666	SG	26.070%	194,137	
Distribution Operations	580	3	1,273,155	SNPD	26.473%	337,037	
Distribution Operations	580	3	1,392,339	OR	Situs	442,491	
Distribution Maintenance	593	3	279,910	SNPD	26.473%	74,099	
Distribution Maintenance	593	3	5,425,914	OR	Situs	1,936,029	
Customer Accounts	903	3	1,488,711	CN	30.990%	461,350	
Customer Accounts	903	3	634,906	OR	Situs	93,815	
Customer Services	908	3	197,890	CN	30.990%	61,326	
Customer Services	908	3	1,832	OTHER	0.000%	-	
Customer Services	908	3	343,834	OR	Situs	116,987	
Administrative & General	920	3	2,642,026	SO	27.173%	717,920	
Administrative & General	920	3	236,721	OR	Situs	66,422	
Administrative & General	935	3	113,501	SO	27.173%	30,842	
Administrative & General	935	3	1,027	OR	Situs	549	
			25,761,520			7,396,589	4.2.2

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.

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. 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, 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.

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). Union and non-union costs were escalated using the contractual and target rates found on page 4.2.4 and 4.2.5.

4. Compensation related to the Annual Incentive Plan (AIP) is included 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.

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.

6. Payroll tax calculations can be found on page 4.2.8.

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	465,243,401	29,970,717	
5002XX	Overtime	78,873,805	84,304,664	5,430,859	
5003XX	Premium Pay	12,492,242	13,352,395	860,154	
	Subtotal for Escalation	**526,638,732**	**562,900,461**	**36,261,729**	4.2.3_.5
5005XX	Unused Leave Accrual	3,238,340	3,461,316	222,976	4.2.6
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)	(1,192,928)	(76,848)	4.2.6
	Subtotal Bare Labor	**535,248,894**	**569,157,475**	**33,908,581**	
500410	Annual Incentive Plan	19,621,442	16,886,838	(2,734,605)	4.2.6
	Total Incentive	**19,621,442**	**16,886,838**	**(2,734,605)**	
500250	Overtime Meals	1,547,581	1,547,581	-	
50040x	Bonus and Awards	5,912,567	5,912,567	-	4.2.6
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**	**7,499,244**	**-**	
	Subtotal Labor and Incentive	**562,369,581**	**593,543,557**	**31,173,977**	
50110X	Pensions	6,136,263	4,818,137	(1,318,127)	4.2.7
501115	SERP Plan	-	-	-	4.2.7
50115X	Post Retirement Benefits	947,520	1,821,623	874,103	4.2.7
501160	Post Employment Benefits	6,401,045	4,691,617	(1,709,428)	4.2.7
	Total Pensions	**13,484,828**	**11,331,377**	**(2,153,451)**	4.2.7
501102	Pension Administration	2,012,320	897,077	(1,115,243)	4.2.7
50112X	Medical	55,789,610	61,261,629	5,472,019	4.2.7
50117X	Dental	3,569,680	4,346,190	776,510	4.2.7
50120X	Vision	257,722	525,727	268,005	4.2.7
50122X	Life	818,089	874,419	56,330	4.2.7
50125X	401(k)	39,576,899	42,301,967	2,725,069	4.2.7
501251	401(k) Administration	(0)	-	0	4.2.7
501275	Accidental Death & Disability	35,043	37,456	2,413	4.2.7
501300	Long-Term Disability	3,936,983	4,208,064	271,081	4.2.7
5016XX	Worker's Compensation	1,156,797	1,236,449	79,651	4.2.7
502900	Other Salary Overhead	611,077	611,077	-	4.2.7
	Total Benefits	**107,764,220**	**116,300,054**	**8,535,834**	4.2.7
	Subtotal Pensions and Benefits	**121,249,048**	**127,631,431**	**6,382,383**	4.2.7
580XXX	Payroll Tax Expense	38,502,103	40,709,542	2,207,439	4.2.8
580700	Payroll Tax Expense-Unemployment	3,138,484	3,138,484	-	
	Total Payroll Taxes	**41,640,586**	**43,848,026**	**2,207,439**	
Total Labor		**725,259,215**	**765,023,015**	**39,763,799**	4.2.11
Non-Utility and Capitalized Labor		255,390,134	269,392,413	14,002,279	4.2.11
Total Utility Labor		**469,869,081**	**495,630,601**	**25,761,520**	4.2.11
				Ref. 4.2	

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**
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**
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**
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**

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)

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

Note: Please see Confidential Exhibit PAC/1004 for redacted information.

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**

Pro Forma Increase to December 2023
Increases occur on the 26th of each month. For this exhibit, each increase is listed on the first day of the following month.

Group Code	Labor Group	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2	Officer/Exempt	[redacted]											
3	IBEW 125	[redacted]											
4	IBEW 659	[redacted]											
5	UWUA 197	[redacted]											
8	UWUA 127	[redacted]											
9	IBEW 57 WY	[redacted]											

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

Note: Please see Confidential Exhibit PAC/1004 for redacted information.

11	IBEW 57 PD	[redacted]
	[redacted]	[redacted]
12	IBEW 57 PS	[redacted]
	[redacted]	[redacted]
13	PCCC Non-Exempt	[redacted]
	[redacted]	[redacted]
15	IBEW 57 CT	[redacted]
	[redacted]	[redacted]
16	IBEW 77	[redacted]
	[redacted]	[redacted]
18	Non-Exempt	[redacted]
	[redacted]	[redacted]

[redacted]

Pro Forma Labor December 2023

Group Code	Labor Group	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Total
2	Officer/Exempt	[redacted]												
3	IBEW 125													
4	IBEW 659													
5	UWUA 197													
8	UWUA 127													
9	IBEW 57 WY													
11	IBEW 57 PD													
12	IBEW 57 PS													
13	PCCC Non-Exempt													
15	IBEW 57 CT													
16	IBEW 77													
18	Non-Exempt													
Grand Total														**562,900**

Ref. 4.2.2

PacifiCorp
Oregon General Rate Case - December 2023
Wage and Employee Benefit Adjustment

Note: Please see Confidential Exhibit PAC/1004 for redacted information.

Composite Labor Increases

			Ref.
Regular Time/Overtime/Premium Pay Annualize - Actual	526,638,732		4.2.2
Regular Time/Overtime/Premium Pay December 2023 - Pro Forma	562,900,461	[1] CAGR	4.2.2
% Increase	6.89%	2.70%	

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	6.89%	3,461,316	**222,976**	4.2.2
Severance	500700	2,823,587	n/a	324,311	**(2,499,276)**	4.2.2 [3]
Joint Owner Cutbacks	50109X	(1,116,081)	6.89%	(1,192,928)	**(76,848)**	4.2.2
		4,945,847		2,592,699	(2,353,148)	

Annual Incentive Plan Escalation

Description	Account	June 2021 Actual	December 2023 Pro Forma	[2] Remove (NEO's) and One-half of Remaining AIP	Pro Forma Adjustment	Ref.
Annual Incentive Plan Compensation	500410	19,621,442	[redacted]	16,886,838	(2,734,605)	4.2.2

[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

PacifiCorp
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**
501115	SERP Plan	0	0	-	-	**(0)**	**4.2.2**
50115X	Post Retirement Benefits	947,520	985,704	1,895,032	1,821,623	**874,103**	**4.2.2**
501160	Post Employment Benefits	6,401,045	6,607,102	4,842,646	4,691,617	**(1,709,428)**	**4.2.2**
	Subtotal	13,484,828	13,833,328	11,637,678	11,331,377	**(2,153,451)**	**4.2.2**
501102	Pension Administration	2,012,320	2,077,285	926,038	897,077	**(1,115,243)**	**4.2.2**
50112X	Medical	55,789,610	57,591,269	63,240,000	61,261,629	**5,472,019**	**4.2.2**
50117X	Dental	3,569,680	3,687,796	4,490,000	4,346,190	**776,510**	**4.2.2**
50120X	Vision	257,722	264,719	540,000	525,727	**268,005**	**4.2.2**
50122X	Life	818,089	846,031	904,285	874,419	**56,330**	**4.2.2**
50125X	401(k)	39,576,899	40,857,477	43,670,720	42,301,967	**2,725,069**	**4.2.2**
501251	401(k) Administration	(0)	6	-	-	**0**	**4.2.2**
501275	Accidental Death & Disability	35,043	35,347	37,780	37,456	**2,413**	**4.2.2**
501300	Long-Term Disability	3,936,983	4,063,380	4,343,164	4,208,064	**271,081**	**4.2.2**
5016XX	Worker's Compensation	1,156,797	1,192,106	1,274,189	1,236,449	**79,651**	**4.2.2**
502900	Other Salary Overhead	611,077	612,112	612,112	611,077	**-**	**4.2.2**
	Subtotal	107,764,220	111,227,527	120,038,287	116,300,054	**8,535,834**	**4.2.2**
	Grand Total	**121,249,048**	125,060,855	131,675,965	**127,631,431**	**6,382,383**	**4.2.2**
		Ref. 4.2.2			**Ref. 4.2.2**	**Ref. 4.2.2**	

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		33,685,605	33,685,605		**4.2.2**
Pro Forma Incentive Adjustment	b		(2,734,605)	(2,734,605)		**4.2.2**
	c	a + b	30,951,001	30,951,001		
Percentage of eligible wages	d		91.65%	100.00%		
Total eligible wages	e	c * d	28,365,320	30,951,001		
Tax rate	f		6.20%	1.45%		
Tax on eligible wages	g	e * f	1,758,650	448,790		
Total FICA Tax on Pro Forma Labor		g	**1,758,650**	**448,790**	**2,207,439**	**4.2.2**

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%	747,436	14,380,060	26.070%	194,859	3,748,931
502SG	19,155,571	2.641%	1,050,243	20,205,814	26.070%	273,802	5,267,725
503SE	89,493	0.012%	4,907	94,399	25.068%	1,230	23,664
505SG	66,888	0.009%	3,667	70,555	26.070%	956	18,394
506SG	30,372,547	4.188%	1,665,236	32,037,783	26.070%	434,133	8,352,360
510SG	4,534,192	0.625%	248,596	4,782,788	26.070%	64,810	1,246,889
511SG	8,134,447	1.122%	445,987	8,580,435	26.070%	116,270	2,236,949
512SG	23,354,332	3.220%	1,280,448	24,634,781	26.070%	333,817	6,422,372
513SG	10,913,109	1.505%	598,333	11,511,442	26.070%	155,988	3,001,072
514SG	2,241,529	0.309%	122,896	2,364,425	26.070%	32,039	616,414
535SG-P	5,273,065	0.727%	289,106	5,562,171	26.070%	75,371	1,450,077
535SG-U	3,351,104	0.462%	183,731	3,534,835	26.070%	47,899	921,544
536SG-P	65,898	0.009%	3,613	69,511	26.070%	942	18,122
537SG-P	510,636	0.070%	27,997	538,633	26.070%	7,299	140,423
537SG-U	28,114	0.004%	1,541	29,655	26.070%	402	7,731
539SG-P	6,399,565	0.882%	350,869	6,750,434	26.070%	91,473	1,759,861
539SG-U	4,965,120	0.685%	272,223	5,237,343	26.070%	70,969	1,365,393
542SG-P	327,201	0.045%	17,939	345,141	26.070%	4,677	89,979
542SG-U	46,799	0.006%	2,566	49,364	26.070%	669	12,869
543SG-P	318,638	0.044%	17,470	336,108	26.070%	4,554	87,624
543SG-U	144,486	0.020%	7,922	152,407	26.070%	2,065	39,733
544SG-P	944,095	0.130%	51,762	995,857	26.070%	13,495	259,623
544SG-U	173,217	0.024%	9,497	182,714	26.070%	2,476	47,634
545SG-P	960,823	0.132%	52,679	1,013,502	26.070%	13,734	264,223
545SG-U	197,353	0.027%	10,820	208,173	26.070%	2,821	54,272
546SG	5,787	0.001%	317	6,104	26.070%	83	1,591
548SG	5,657,523	0.780%	310,185	5,967,708	26.070%	80,866	1,555,802
549OR	19,124	0.003%	1,048.52	20,173	Situs	1,048.52	20,173
549SG	4,376,273	0.603%	239,938	4,616,211	26.070%	62,553	1,203,462
552SG	1,064,019	0.147%	58,337	1,122,356	26.070%	15,209	292,602
553SG	2,089,352	0.288%	114,553	2,203,905	26.070%	29,864	574,566
554SG	85,332	0.012%	4,679	90,011	26.070%	1,220	23,466
556SG	263,837	0.036%	14,465	278,302	26.070%	3,771	72,554
557ID	69,384	0.010%	3,804	73,188	Situs	-	-
557SG	29,009,710	4.000%	1,590,516	30,600,226	26.070%	414,653	7,977,583
560SG	8,483,712	1.170%	465,137	8,948,848	26.070%	121,263	2,332,995
561SG	10,621,907	1.465%	582,367	11,204,275	26.070%	151,825	2,920,993
562SG	1,730,531	0.239%	94,880	1,825,411	26.070%	24,735	475,891
563SG	505,793	0.070%	27,731	533,525	26.070%	7,230	139,092
566SG	74,754	0.010%	4,099	78,852	26.070%	1,068	20,557
567SG	101,169	0.014%	5,547	106,716	26.070%	1,446	27,821
568SG	883,480	0.122%	48,439	931,919	26.070%	12,628	242,954
569SG	2,754,076	0.380%	150,998	2,905,074	26.070%	39,366	757,363
570SG	6,311,786	0.870%	346,056	6,657,843	26.070%	90,218	1,735,722
571SG	3,581,589	0.494%	196,368	3,777,956	26.070%	51,194	984,926
572SG	51,161	0.007%	2,805	53,966	26.070%	731	14,069
580CA	(1,637)	0.000%	(90)	(1,727)	Situs	-	-
580ID	45,109	0.006%	2,473	47,582	Situs	-	-
580OR	319,311	0.044%	17,506.85	336,818	Situs	17,506.85	336,818
580SNPD	7,549,492	1.041%	413,916	7,963,408	26.473%	109,574	2,108,121
580UT	57,344	0.008%	3,144	60,488	Situs	-	-
580WA	335,385	0.046%	18,388	353,773	Situs	-	-
580WYP	86,611	0.012%	4,749	91,360	Situs	-	-
581SNPD	12,876,362	1.775%	705,973	13,582,335	26.473%	186,889	3,595,597
582CA	32,613	0.004%	1,788	34,401	Situs	-	-
582ID	110,031	0.015%	6,033	116,063	Situs	-	-
582OR	316,930	0.044%	17,376.34	334,307	Situs	17,376.34	334,307
582SNPD	979	0.000%	54	1,032	26.473%	14	273
582UT	757,951	0.105%	41,556	799,508	Situs	-	-
582WA	99,612	0.014%	5,461	105,073	Situs	-	-
582WYP	390,342	0.054%	21,401	411,743	Situs	-	-
583CA	636,751	0.088%	34,911	671,662	Situs	-	-
583ID	217,551	0.030%	11,928	229,479	Situs	-	-
583OR	1,323,385	0.182%	72,557.26	1,395,942	Situs	72,557.26	1,395,942
583SNPD	163	0.000%	9	172	26.473%	2	45
583UT	4,466,428	0.616%	244,881	4,711,309	Situs	-	-
583WA	256,645	0.035%	14,071	270,716	Situs	-	-
583WYP	255,410	0.035%	14,003	269,414	Situs	-	-
583WYU	58,617	0.008%	3,214	61,830	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%	13,672	263,033	26.473%	3,619	69,632
586CA	82,097	0.011%	4,501	86,598	Situs	-	-
586ID	139,542	0.019%	7,651	147,193	Situs	-	-
586OR	1,027,193	0.142%	56,317.95	1,083,511	Situs	56,317.95	1,083,511
586UT	405,264	0.056%	22,219	427,483	Situs	-	-
586WA	297,130	0.041%	16,291	313,421	Situs	-	-
586WYP	201,095	0.028%	11,025	212,121	Situs	-	-
586WYU	66,447	0.009%	3,643	70,091	Situs	-	-
587CA	438,562	0.060%	24,045	462,607	Situs	-	-
587ID	681,114	0.094%	37,343	718,457	Situs	-	-
587OR	5,038,483	0.695%	276,244.97	5,314,728	Situs	276,244.97	5,314,728
587UT	4,431,429	0.611%	242,962	4,674,391	Situs	-	-
587WA	1,065,097	0.147%	58,396	1,123,493	Situs	-	-
587WYP	963,538	0.133%	52,828	1,016,366	Situs	-	-
587WYU	92,288	0.013%	5,060	97,348	Situs	-	-
588CA	(17,937)	-0.002%	(983)	(18,921)	Situs	-	-
588ID	(8,402)	-0.001%	(461)	(8,862)	Situs	-	-
588OR	(69,351)	-0.010%	(3,802.33)	(73,154)	Situs	(3,802.33)	(73,154)
588SNPD	2,544,950	0.351%	139,532	2,684,482	26.473%	36,938	710,652
588UT	247,754	0.034%	13,584	261,337	Situs	-	-
588WA	7,200	0.001%	395	7,595	Situs	-	-
588WYP	(365)	0.000%	(20)	(385)	Situs	-	-
588WYU	(53,280)	-0.007%	(2,921)	(56,201)	Situs	-	-
589CA	20,049	0.003%	1,099	21,148	Situs	-	-
589ID	14,424	0.002%	791	15,215	Situs	-	-
589OR	114,722	0.016%	6,289.86	121,012	Situs	6,289.86	121,012
589UT	335,267	0.046%	18,382	353,649	Situs	-	-
589WA	10,734	0.001%	589	11,322	Situs	-	-
589WYP	88,779	0.012%	4,868	93,647	Situs	-	-
589WYU	11,861	0.002%	650	12,511	Situs	-	-
590CA	102,277	0.014%	5,608	107,885	Situs	-	-
590ID	218,231	0.030%	11,965	230,196	Situs	-	-
590OR	700,167	0.097%	38,388.07	738,555	Situs	38,388.07	738,555
590SNPD	2,586,908	0.357%	141,832	2,728,740	26.473%	37,547	722,368
590UT	913,615	0.126%	50,091	963,706	Situs	-	-
590WA	166,440	0.023%	9,125	175,565	Situs	-	-
590WYP	349,882	0.048%	19,183	369,065	Situs	-	-
591SNPD	421	0.000%	23	445	26.473%	6	118
592CA	516,199	0.071%	28,302	544,501	Situs	-	-
592ID	273,616	0.038%	15,002	288,617	Situs	-	-
592OR	2,002,428	0.276%	109,787.17	2,112,216	Situs	109,787.17	2,112,216
592SNPD	1,335,668	0.184%	73,231	1,408,899	26.473%	19,386	372,972
592UT	1,461,818	0.202%	80,147	1,541,965	Situs	-	-
592WA	413,294	0.057%	22,660	435,954	Situs	-	-
592WYP	583,579	0.080%	31,996	615,575	Situs	-	-
593CA	4,642,317	0.640%	254,524	4,896,841	Situs	-	-
593ID	4,566,290	0.630%	250,356	4,816,646	Situs	-	-
593OR	28,068,609	3.870%	1,538,918.13	29,607,528	Situs	1,538,918.13	29,607,528
593SNPD	1,847,350	0.255%	101,285	1,948,635	26.473%	26,813	515,854
593UT	27,802,996	3.834%	1,524,355	29,327,352	Situs	-	-
593WA	4,351,067	0.600%	238,556	4,589,623	Situs	-	-
593WYP	6,864,745	0.947%	376,373	7,241,119	Situs	-	-
593WYU	612,106	0.084%	33,560	645,665	Situs	-	-
594CA	318,476	0.044%	17,461	335,937	Situs	-	-
594ID	412,481	0.057%	22,615	435,096	Situs	-	-
594OR	3,901,319	0.538%	213,897.67	4,115,216	Situs	213,897.67	4,115,216
594SNPD	18,455	0.003%	1,012	19,467	26.473%	268	5,153
594UT	6,585,836	0.908%	361,082	6,946,918	Situs	-	-
594WA	864,643	0.119%	47,406	912,049	Situs	-	-
594WYP	597,900	0.082%	32,781	630,682	Situs	-	-
594WYU	91,719	0.013%	5,029	96,747	Situs	-	-
595SNPD	959,144	0.132%	52,587	1,011,731	26.473%	13,921	267,832
596CA	37,045	0.005%	2,031	39,077	Situs	-	-
596ID	44,578	0.006%	2,444	47,022	Situs	-	-
596OR	442,012	0.061%	24,234.21	466,246	Situs	24,234.21	466,246
596UT	162,385	0.022%	8,903	171,288	Situs	-	-
596WA	27,712	0.004%	1,519	29,232	Situs	-	-
596WYP	247,587	0.034%	13,574	261,162	Situs	-	-
596WYU	31,037	0.004%	1,702	32,739	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%	702	13,502	Situs	-	-
597ID	27,373	0.004%	1,501	28,874	Situs	-	-
597OR	173,588	0.024%	9,517.29	183,105	Situs	9,517.29	183,105
597SNPD	(70,295)	-0.010%	(3,854)	(74,149)	26.473%	(1,020)	(19,629)
597UT	262,165	0.036%	14,374	276,539	Situs	-	-
597WA	21,109	0.003%	1,157	22,267	Situs	-	-
597WYP	17,829	0.002%	978	18,807	Situs	-	-
597WYU	18,826	0.003%	1,032	19,859	Situs	-	-
598CA	5,497	0.001%	301	5,799	Situs	-	-
598OR	23,466	0.003%	1,286.60	24,753	Situs	1,286.60	24,753
598SNPD	(1,572,321)	-0.217%	(86,206)	(1,658,526)	26.473%	(22,821)	(439,055)
598WA	27,182	0.004%	1,490	28,673	Situs	-	-
901CN	1,689,675	0.233%	92,640	1,782,315	30.990%	28,709	552,338
902CA	314,956	0.043%	17,268	332,224	Situs	-	-
902CN	303,805	0.042%	16,657	320,461	30.990%	5,162	99,311
902ID	1,610,394	0.222%	88,293	1,698,687	Situs	-	-
902OR	1,407,414	0.194%	77,164.32	1,484,578	Situs	77,164.32	1,484,578
902UT	4,421,298	0.610%	242,407	4,663,705	Situs	-	-
902WA	888,713	0.123%	48,725	937,439	Situs	-	-
902WYP	772,799	0.107%	42,370	815,169	Situs	-	-
902WYU	144,870	0.020%	7,943	152,813	Situs	-	-
903CA	17,721	0.002%	972	18,693	Situs	-	-
903CN	25,159,388	3.469%	1,379,414	26,538,802	30.990%	427,479	8,224,356
903ID	220,123	0.030%	12,069	232,192	Situs	-	-
903OR	303,686	0.042%	16,650.21	320,336	Situs	16,650.21	320,336
903UT	1,076,476	0.148%	59,020	1,135,496	Situs	-	-
903WA	85,485	0.012%	4,687	90,172	Situs	-	-
903WYP	264,505	0.036%	14,502	279,007	Situs	-	-
903WYU	51,717	0.007%	2,836	54,553	Situs	-	-
907CN	2,858	0.000%	157	3,015	30.990%	49	934
908CA	27	0.000%	1	29	Situs	-	-
908CN	1,913,425	0.264%	104,907	2,018,332	30.990%	32,511	625,480
908ID	14,124	0.002%	774	14,898	Situs	-	-
908OR	2,133,756	0.294%	116,987.47	2,250,743	Situs	116,987.47	2,250,743
908OTHER	33,413	0.005%	1,832	35,245	0.000%	-	-
908UT	2,846,724	0.393%	156,077	3,002,802	Situs	-	-
908WA	319,510	0.044%	17,518	337,028	Situs	-	-
908WYP	957,109	0.132%	52,475	1,009,585	Situs	-	-
909CN	1,693,067	0.233%	92,826	1,785,893	30.990%	28,767	553,447
920OR	907,381	0.125%	49,748.97	957,130	Situs	49,748.97	957,130
920SO	75,668,430	10.433%	4,148,674	79,817,104	27.173%	1,127,323	21,688,767
920UT	1,534,150	0.212%	84,113	1,618,263	Situs	-	-
920WYP	509,969	0.070%	27,960	537,929	Situs	-	-
921SO	3,300,981	0.455%	180,983	3,481,963	27.173%	49,179	946,157
922SO	(27,772,793)	-3.829%	(1,522,699)	(29,295,492)	27.173%	(413,764)	(7,960,488)
928CA	3,589	0.000%	197	3,785	Situs	-	-
928ID	139,776	0.019%	7,664	147,440	Situs	-	-
928OR	304,110	0.042%	16,673.46	320,784	Situs	16,673.46	320,784
928SO	383,123	0.053%	21,006	404,129	27.173%	5,708	109,814
928UT	368,546	0.051%	20,206	388,752	Situs	-	-
928WA	88,677	0.012%	4,862	93,538	Situs	-	-
928WYP	461,408	0.064%	25,298	486,705	Situs	-	-
929SO	(3,391,347)	-0.468%	(185,937)	(3,577,284)	27.173%	(50,525)	(972,058)
935CA	5,461	0.001%	299	5,760	Situs	-	-
935OR	10,008	0.001%	548.72	10,557	Situs	548.72	10,557
935SO	2,070,162	0.285%	113,501	2,183,662	27.173%	30,842	593,368
935WA	3,264	0.000%	179	3,443	Situs	-	-
Utility Labor	**469,869,081**	**64.786%**	**25,761,520**	**495,630,601**		**7,396,589**	**142,304,332**
						Ref 4.2	
Capital/Non Utility	255,390,134	35.214%	14,002,279	269,392,413			
Total Labor	**725,259,215**	**100.00%**	**39,763,799**	**765,023,015**			
	Ref 4.2.2	**Ref 4.2.2**	**Ref 4.2.2**	**Ref 4.2.2**			

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	2,871,029	SO	27.173%	780,147	4.3.1
Post-Retirement Non-Service Exp.	926	3	867,276	SO	27.173%	235,666	4.3.1
SERP Non-Service Expense	926	3	(2,768,076)	SO	27.173%	(752,171)	4.3.1
			970,230			263,641	
Pension Settle. Loss Amortization Exp.	926	3	1,271,364	SO	27.173%	345,469	4.3.3

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.

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	(311,307)	(167,183)	-	(478,490)	926	SO
Feb-2023	(311,307)	(167,183)	-	(478,490)	926	SO
Mar-2023	(311,307)	(167,183)	-	(478,490)	926	SO
Apr-2023	(311,307)	(167,183)	-	(478,490)	926	SO
May-2023	(311,307)	(167,183)	-	(478,490)	926	SO
Jun-2023	(311,307)	(167,183)	-	(478,490)	926	SO
Jul-2023	(311,307)	(167,183)	-	(478,490)	926	SO
Aug-2023	(311,307)	(167,183)	-	(478,490)	926	SO
Sep-2023	(311,307)	(167,183)	-	(478,490)	926	SO
Oct-2023	(311,307)	(167,183)	-	(478,490)	926	SO
Nov-2023	(311,307)	(167,183)	-	(478,490)	926	SO
Dec-2023	(311,307)	(167,183)	-	(478,490)	926	SO
Total Forecasted	**(3,735,685)**	**(2,006,190)**	**-**	**(5,741,875)**		
Total Incremental Change	**2,871,029**	**867,276**	**(2,768,076)**	**970,230**		
	Ref 4.3	**Ref 4.3**	**Ref 4.3**	**Ref 4.3**		

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	9,780,891	65,193	926	SO
	25,427,278	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	-	105,947	926	SO
Feb-23	-	105,947	926	SO
Mar-23	-	105,947	926	SO
Apr-23	-	105,947	926	SO
May-23	-	105,947	926	SO
Jun-23	-	105,947	926	SO
Jul-23	-	105,947	926	SO
Aug-23	-	105,947	926	SO
Sep-23	-	105,947	926	SO
Oct-23	-	105,947	926	SO
Nov-23	-	105,947	926	SO
Dec-23	-	105,947	926	SO
Total Incurred	**-**	**1,271,364**		
		Ref 4.3		

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	26.070%	(8,603,213)	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.

PacifiCorp
Oregon General Rate Case - December 2023
Remove Non-Recurring Entries

FERC Account	Account Number	Description	Amount	Alloc	REF
5459000	545500	Reversal of Klamath Settlement Obligation Expense Accrual	33,000,000	SG	Ref. 4.4

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	27.173%	(37,864,307)	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	1,608,709	OR	Situs	1,608,709	4.5.2
Adjust property damage expense to 10-year average							
Property Insurance - Transmission	924	3	34,764	OR	Situs	34,764	4.5.3
Property Insurance - OR Dist.	924	3	2,355,785	OR	Situs	2,355,785	4.5.3
Property Insurance - Non-T&D	924	3	(85,052)	OR	Situs	(85,052)	4.5.3
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	27.173%	5,649,850	4.5.5
Adjust Property Insurance Premium	924	3	(758,963)	SO	27.173%	(206,234)	4.5.5
Adjustment to Rate Base:							
Remove Injuries & Damages Reserve	2282	3	141,155,665	SO	27.173%	38,356,344	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	27.173%	(9,430,521)	

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.

PacifiCorp
Oregon General Rate Case - December 2023
Insurance Expense
Injuries and Damages in Unadjusted Results

Amount in Unadjusted Results

G/L Account	Account Title	Allocator	Amount	
	Net Base Year Expense	SO	**139,344,910**	
			Ref 4.5	
545052	Inj/Damage Ins Prov - OR	OR	**1,484,743**	
			Ref 4.5	

Injuries & Damages Reserve

			EOP Balance Jun-21	
	Net Base Year Reserve	SO	**(141,155,665)**	**Ref 4.5**

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 %			27.173%					
Oregon Allocated Annual Accrual			**1,608,709**					
			Ref 4.5					

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 %	26.070%	100%	26.070%
June 2021 - Oregon Allocated 10 Year Average	280,496	10,443,216	184,323
UE - 374 - Oregon Allocated 10 Year Average	245,732	8,087,431	269,375
Adjustment	**34,764**	**2,355,785**	**(85,052)**
	Ref 4.5	**Ref 4.5**	**Ref 4.5**

PacifiCorp
Oregon General Rate Case - December 2023
Insurance Expense
Property Damage Reserve - Amortize the June 2021 EOP Balance Over 10 Years

OR Property Damages Reserve		EOP Balance Jun-21	
288712	Reg Liab - OR Property Insurance Reserve	20,937,606	
	Annual Amount per Year	**2,093,761**	**Ref 4.5**

PacifiCorp
Oregon General Rate Case - December 2023
Insurance Expense
Adjust Base Period Liability Insurance Premium to CY 2021/2022 Level

Adjusting the insurance premium in the base period to the renewed amount effective August 15, 2021

	Premium Renewal 2021/2022	Included in Results 12 Months Ended Jun-21	Adjustment	
Excess Liability Insurance Premium	29,182,860	8,390,777	**20,792,083**	**Ref 4.5**
Property Insurance Premium	4,127,137	4,886,099	**(758,963)**	**Ref 4.5**
	33,309,997			

PacifiCorp
Oregon General Rate Case - December 2023
Generation Overhaul Expense

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Generation Overhaul Expense - Steam	510	1	569,022	SG	26.070%	148,346	4.6.1
Generation Overhaul Expense - Other	553	1	3,163,574	SG	26.070%	824,755	4.6.1
			3,732,596			973,101	

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.

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	10.26%	25,446,076	
12 Months Ended June 2019	32,510,459	(52,000)	32,458,459	6.64%	34,614,331	
12 Months Ended June 2020	24,450,349	-	24,450,349	4.68%	25,595,197	
12 Months Ended June 2021	27,793,172	-	27,793,172	0.00%	27,793,172	
4 Year Average - Steam					28,362,194	
12 Months Ended June 2021 Overhaul Expense - Steam					27,793,172	**Ref. 4.6.2**
Adjustment					**569,022**	**Ref. 4.6**

FUNCTION: OTHER

Period	Overhaul Expense	Restate to Constant Dollars (1)	Constant Dollars	
12 Months Ended June 2018	5,647,997	8.78%	6,143,831	
12 Months Ended June 2019	2,093,159	5.68%	2,212,147	
12 Months Ended June 2020	10,103,281	3.62%	10,469,199	
12 Months Ended June 2021	2,056,960	0.00%	2,056,960	
4 Year Average			5,220,534	
12 Months Ended June 2021 Overhaul Expense - Other			2,056,960	**Ref. 4.6.2**
Adjustment			**3,163,574**	**Ref. 4.6**
Total Adjustment			**3,732,596**	**Ref. 4.6**

(1) Ref. 4.6.3

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**
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**
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	**10.26%**	**6.64%**	**4.68%**	**0.00%**

OTHER:	**June 2018**	**June 2019**	**June 2020**	**June 2021**
Percentage Change to June 2021	**8.78%**	**5.68%**	**3.62%**	**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	(274,522)	OR	Situs	(274,522)	4.7.1
Other Taxes	408	3	(1,473,948)	OR	Situs	(1,473,948)	4.7.1
Regulatory Commission Exp	928	3	(227,655)	OR	Situs	(227,655)	4.7.1

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.

PacifiCorp
Oregon General Rate Case - December 2023
Revenue Sensitive Items & Uncollectibles

Unadjusted Revenue	1,308,339,123	
Normalized Revenue	1,247,631,024	
Adjustments	(60,708,099)	
Uncollectible Expense in Base Period	5,916,318	
Uncollectible %	0.452%	
Uncollectible Expense	**(274,522)**	**Ref. 4.7**
Franchise Tax %	**2.3028%**	**Ref. 4.7.2**
Resource Supplier Tax %	**0.1252%**	**Ref. 4.7.2**
Other Tax Expense	**(1,473,948)**	**Ref. 4.7**
PUC Fees %	0.375%	
PUC Fees Expense	**(227,655)**	**Ref. 4.7**

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%** **Ref. 4.7.1** **1/3(d) +1/3(e) + 1/3(f)**	2.233% **(d)**	2.294% **(e)**	2.381% **(f)**	**(c) = (b)/(a)**

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%** **Ref. 4.7.1** **1/3(d) +1/3(e) + 1/3(f)**	0.129% **(d)**	0.129% **(e)**	0.117% **(f)**	**(c) = (b)/(a)**

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	27.173%	(448,423)	
	930	1	(130)	OR	Situs	(130)	
Total			(1,650,378)			(448,553)	4.8.1
Add Back 75% of National & Regional Memberships							
Various	930	1	1,113,129	SO	27.173%	302,471	
Total			1,113,129			302,471	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.

PacifiCorp
Oregon General Rate Case - December 2023
Memberships and Subscriptions

Account	Factor	Description	Amount	
Remove Total Memberships and Subscriptions in Account 930.2				
930.2	SO	Included in Unadjusted Results	(1,650,248)	
930.2	OR	Included in Unadjusted Results	(130)	
			(1,650,378)	**Ref 4.8**
Allowed National and Regional Trade Memberships at 75%				
930.2	SO	Albany Area Chamber of Commerce	2,225	
930.2	SO	Albany Downtown Association & Park Wise	180	
930.2	SO	American Wind Wildlife Institute	23,333	
930.2	SO	Astoria Downtown Historic District Association	500	
930.2	SO	Bay Area Chamber of Commerce	1,019	
930.2	SO	Bend Chamber of Commerce	1,725	
930.2	SO	Cannon Beach Chamber of Commerce	310	
930.2	SO	Central Point Chamber of Commerce	250	
930.2	SO	Clatsop Economic Development Resources	5,000	
930.2	SO	Columbia Corridor Association	3,000	
930.2	SO	Columbia River Maritime Museum	500	
930.2	SO	Common Ground Alliance	2,500	
930.2	SO	Corvallis Chamber of Commerce	3,500	
930.2	SO	Cottage Grove Chamber of Commerce	300	
930.2	SO	Dallas Area Visitors Center	600	
930.2	SO	Douglas Timber Operators	600	
930.2	SO	East-Linn Utilities Coordinating Council	125	
930.2	SO	Economic Development for Central Oregon	7,500	
930.2	SO	Edison Electric Institute	988,312	
930.2	SO	Energy Storage Association	3,375	
930.2	SO	Energy Systems Integration Group	1,618	
930.2	SO	Forth (Drive Oregon)	1,500	
930.2	SO	Grants Pass Josephine County Chamber of Commerce	275	
930.2	SO	Greater Albany Rotary Club	281	
930.2	SO	GridForward	5,000	
930.2	SO	Intermountain Electrical Association	9,500	
930.2	SO	International Economic Development Council	455	
930.2	SO	Klamath County Chamber of Commerce	799	
930.2	SO	Klamath County Economic Development Association	5,000	
930.2	SO	Klamath Forest Protective Association	26	
930.2	SO	Lake County Chamber of Commence	500	
930.2	SO	Lane Utilities Coordinating Council	100	
930.2	SO	League of Oregon Cities	600	
930.2	SO	Lebanon Area Chamber of Commerce	1,600	
930.2	SO	Linkville Kiwanis Club-Klamath Falls	115	
930.2	SO	Linn-Benton Utilities Coordinating Council	125	
930.2	SO	Madras Jefferson County Chamber	385	
930.2	SO	Madras-Jefferson County Chamber of Commerce	385	
930.2	SO	Metropolitan Utility Coordinating Council	150	
930.2	SO	Monmouth- Independence Chamber of Commerce	1,200	
930.2	SO	Myrtle Creek-Tri City Area Chamber of Commerce	105	
930.2	SO	North American Transmission Forum	95,167	
930.2	SO	North Santiam Chamber of Commerce	1,000	
930.2	SO	Northwest Hydroelectric Association	1,200	
930.2	SO	Northwest Public Power Association	185	
930.2	SO	Oregon Business Council	24,879	
930.2	SO	Oregon Energy Fund	75	
930.2	SO	Oregon State University, Utility Pole Research Cooperative	15,000	
930.2	SO	Pacific Northwest Utilities Conference Committee	118,788	
930.2	SO	Pendleton Chamber of Commerce	635	
930.2	SO	Pilot Rock Chamber of Commerce	50	
930.2	SO	Portland Business Alliance: Partners in Diversity	36,243	
930.2	SO	Princeville Chamber of Commerce	240	
930.2	SO	Redmond Economic Development, Inc.	5,000	
930.2	SO	Rocky Mountain Electrical League	18,000	
930.2	SO	Roseburg Area Chamber of Commerce	1,090	
930.2	SO	Rotary Club of Albina	225	
930.2	SO	Rotary Club of Roseburg	345	
930.2	SO	Seaside Chamber of Commerce	395	
930.2	SO	Seaside Downtown Development Association	175	
930.2	SO	South Lincoln County Economic Development Corporation	1,000	
930.2	SO	Southern Oregon Regional Economic Development, Inc.	2,500	
930.2	SO	Sport Oregon	5,000	
930.2	SO	Stayton-Sublimity Chamber of Commerce	2,149	
930.2	SO	Strategic Economic Development Corporation	1,400	
930.2	SO	Sutherlin Chamber of Commerce	125	
930.2	SO	Takena Kiwanis	130	
930.2	SO	The Chamber of Medford/Jackson County	2,247	
930.2	SO	The Enterprise	750	
930.2	SO	The National Hydropower Association, Inc.	45,384	

PacifiCorp
Oregon General Rate Case - December 2023
Memberships and Subscriptions

Account	Factor	Description	Amount	
930.2	SO	Tri-County Chamber of Commerce	255	
930.2	SO	Umpqua Economic Development Partnership	2,500	
930.2	SO	Umpqua Lions Club	75	
930.2	SO	Utility Economic Development Association, Inc.	745	
930.2	SO	Western Energy Supply Transmission Associates	20,548	
930.2	SO	Western Labor And Management Public Affairs Committee	4,000	
930.2	SO	Women's Energy Network	2,100	
			1,484,172	
		Allowed Memberships and Subscriptions - 75% of amount above	**1,113,129**	**Ref 4.8**

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	26.070%	(14)	
	502	1	1	SG	26.070%	0	
	506	1	(1,586)	SG	26.070%	(413)	
	514	1	(22)	SG	26.070%	(6)	
	535	1	(53)	SG-P	26.070%	(14)	
	535	1	(2,222)	SG-U	26.070%	(579)	
	539	1	53	SG	26.070%	14	
	539	1	(0)	SG-U	26.070%	(0)	
	546	1	(12)	SG	26.070%	(3)	
	548	1	(278)	SG	26.070%	(72)	
	549	1	(2,310)	SG	26.070%	(602)	
	553	1	(514)	SG	26.070%	(134)	
	557	1	(13,561)	SG	26.070%	(3,535)	
	560	1	(892)	SG	26.070%	(233)	
	561	1	(142)	SG	26.070%	(37)	
	570	1	(0)	SG	26.070%	(0)	
	571	1	(0)	SG	26.070%	(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	27.173%	(2,625)	
			(61,751)			(20,671)	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%.

PacifiCorp
Oregon General Rate Case - December 2023
Meals & Entertainment Adjustment
Summary of Adjustments

Meals and Entertainment 50% Adjustment

FERC Account	Allocation	Amount
500	SG	106
501	SE	-
502	SG	(2)
505	SG	-
506	SG	2,694
514	SG	43
535	SG-P	105
535	SG-U	4,444
537	SG-P	-
539	SG-P	(107)
539	SG-U	0
546	SG	24
548	SG	111
549	OR	-
549	SG	4,620
553	SG	1,028
557	SG	27,122
560	SG	1,688
561	SG	285
568	SG	-
569	SG	-
570	SG	0
571	SG	0
580	OR	5,457
580	SNPD	9,358
581	SNPD	143
585	SNPD	373
588	OR	(1)
590	SNPD	14,580
592	OR	-
592	SNPD	3,241
593	OR	(0)
593	SNPD	16,721
595	SNPD	886
598	SNPD	205
901	CN	1,337
903	CN	218
903	OR	-
908	CN	1,084
908	OR	6,117
909	CN	1,155
921	SO	15,750
935	OR	-
Grand Total		118,783

Awards 50% Adjustment

FERC Account	Allocation	Amount
506	SG	477
548	SG	446
560	SG	97
903	CN	125
921	SO	3,573
929	SO	-
Grand Total		4,718

Meals & Entertainment	118,783	
Disallowance	-50%	
Removal	(59,392)	
Awards	4,718	
Disallowance	-50%	
Removal	(2,359)	
Total Disallowance	**(61,751)**	**Ref 4.9**

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	19,118	SG	26.070%	4,984	
Steam Operations	500	3	88,937	SG	26.070%	23,186	
Steam Operations	501	3	1,374,066	SE	25.068%	344,453	
Steam Operations	501	3	21,692	SE	25.068%	5,438	
Steam Operations	501	3	509,037	OR	Situs	403,598	
Steam Operations	502	3	4,621,099	SG	26.070%	1,204,736	
Steam Operations	502	3	378,684	SG	26.070%	98,724	
Steam Operations	503	3	(7,339)	SE	25.068%	(1,840)	
Steam Operations	505	3	-	SG	26.070%	-	
Steam Operations	505	3	79,942	SG	26.070%	20,841	
Steam Operations	505	3	10,757	SG	26.070%	2,804	
Steam Operations	506	3	(4,102,827)	SG	26.070%	(1,069,621)	
Steam Operations	506	3	2,214,631	SG	26.070%	577,362	
Steam Operations	506	3	118,803	SG	26.070%	30,972	
Steam Operations	507	3	-	SG	26.070%	-	
Steam Operations	507	3	38,270	SG	26.070%	9,977	
Steam Operations	507	3	19	SG	26.070%	5	
Steam Maintenance	510	3	39,841	SG	26.070%	10,387	
Steam Maintenance	510	3	101,935	SG	26.070%	26,575	
Steam Maintenance	510	3	74,514	SG	26.070%	19,426	
Steam Maintenance	511	3	971,654	SG	26.070%	253,313	
Steam Maintenance	511	3	178,479	SG	26.070%	46,530	
Steam Maintenance	512	3	-	SG	26.070%	-	
Steam Maintenance	512	3	3,120,202	SG	26.070%	813,447	
Steam Maintenance	512	3	122,102	SG	26.070%	31,832	
Steam Maintenance	513	3	-	SG	26.070%	-	
Steam Maintenance	513	3	1,412,947	SG	26.070%	368,360	
Steam Maintenance	513	3	21,061	SG	26.070%	5,491	
Steam Maintenance	514	3	583,815	SG	26.070%	152,203	
Steam Maintenance	514	3	102,387	SG	26.070%	26,693	
Hydro Operations	535	3	397,265	SG	26.070%	103,568	
Hydro Operations	535	3	(162,715)	SG	26.070%	(42,420)	
Hydro Operations	536	3	21,672	SG	26.070%	5,650	
Hydro Operations	536	3	-	SG	26.070%	-	
Hydro Operations	537	3	345,922	SG	26.070%	90,183	
Hydro Operations	537	3	27,466	SG	26.070%	7,160	
Hydro Operations	539	3	510,190	SG	26.070%	133,008	
Hydro Operations	539	3	149,763	SG	26.070%	39,044	
Hydro Operations	539	3	5	SG	26.070%	1	
Hydro Operations	540	3	135,640	SG	26.070%	35,362	
Hydro Operations	540	3	6,055	SG	26.070%	1,579	
			13,525,091			3,783,013	

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.

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	28	SG	26.070%	7	
Hydro Maintenance	541	3	-	SG	26.070%	-	
Hydro Maintenance	542	3	30,367	SG	26.070%	7,917	
Hydro Maintenance	542	3	1,912	SG	26.070%	499	
Hydro Maintenance	543	3	27,439	SG	26.070%	7,153	
Hydro Maintenance	543	3	15,397	SG	26.070%	4,014	
Hydro Maintenance	544	3	50,023	SG	26.070%	13,041	
Hydro Maintenance	544	3	5,672	SG	26.070%	1,479	
Hydro Maintenance	545	3	149,610	SG	26.070%	39,004	
Hydro Maintenance	545	3	46,778	SG	26.070%	12,195	
Hydro Maintenance	545	3	-	SG	26.070%	-	
Other Operations	546	3	27,446	SG	26.070%	7,155	
Other Operations	546	3	(1)	SG	26.070%	(0)	
Other Operations	547	3	-	SE	25.068%	-	
Other Operations	548	3	(24)	SG	26.070%	(6)	
Other Operations	547	3	-	SE	25.068%	-	
Other Operations	548	3	1,055,932	SG	26.070%	275,285	
Other Operations	548	3	23,782	SG	26.070%	6,200	
Other Operations	549	3	1,157	OR	Situs	1,157	
Other Operations	549	3	(2,683)	SG	26.070%	(699)	
Other Operations	549	3	(1,201)	SG	26.070%	(313)	
Other Operations	549	3	363,216	SG	26.070%	94,692	
Other Operations	550	3	32,953	OR	Situs	32,953	
Other Operations	550	3	-	SG	26.070%	-	
Other Operations	550	3	3,559	SG	26.070%	928	
Other Operations	550	3	647,675	SG	26.070%	168,851	
Other Operations	550	3	-	SG	26.070%	-	
Other Maintenance	552	3	-	SG	26.070%	-	
Other Maintenance	552	3	89,083	SG	26.070%	23,224	
Other Maintenance	552	3	1,159	SG	26.070%	302	
Other Maintenance	553	3	143,506	SG	26.070%	37,413	
Other Maintenance	553	3	741,438	SG	26.070%	193,295	
Other Maintenance	553	3	163,220	SG	26.070%	42,552	
Other Maintenance	553	3	10,225	SG	26.070%	2,666	
Other Maintenance	554	3	-	SG	26.070%	-	
Other Maintenance	554	3	69,933	SG	26.070%	18,232	
Other Maintenance	554	3	140,760	SG	26.070%	36,697	
Other Maintenance	554	3	2,546	SG	26.070%	664	
			3,840,907			1,026,555	

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.

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	28,994	SG	26.070%	7,559	
Other Operations	557	3	594,109	OR	Situs	266,179	
Other Operations	557	3	520,616	SG	26.070%	135,726	
Other Operations	557	3	746	SE	25.068%	187	
Other Operations	557	3	-	SG	26.070%	-	
Transmission Operations	560	3	23,182	SG	26.070%	6,044	
Transmission Operations	560	3	(41)	SG	26.070%	(11)	
Transmission Operations	561	3	330,817	SG	26.070%	86,245	
Transmission Operations	561	3	(7)	SG	26.070%	(2)	
Transmission Operations	562	3	69,347	SG	26.070%	18,079	
Transmission Operations	563	3	21,063	SG	26.070%	5,491	
Transmission Operations	566	3	163,442	SG	26.070%	42,610	
Transmission Operations	567	3	110,085	SG	26.070%	28,699	
Transmission Maintenance	568	3	(3,212)	SG	26.070%	(837)	
Transmission Maintenance	569	3	207,778	SG	26.070%	54,168	
Transmission Maintenance	570	3	335,311	SG	26.070%	87,417	
Transmission Maintenance	571	3	1,176,963	SG	26.070%	306,838	
Transmission Maintenance	571	3	(181,711)	SG	26.070%	(47,373)	
Transmission Maintenance	572	3	9,930	SG	26.070%	2,589	
Transmission Maintenance	573	3	14,801	SG	26.070%	3,859	
Distribution Operations	580	3	63,842	OR	Situs	8,153	
Distribution Operations	580	3	42,639	SNPD	26.473%	11,288	
Distribution Operations	581	3	-	OR	Situs	-	
Distribution Operations	581	3	(12,098)	SNPD	26.473%	(3,203)	
Distribution Operations	582	3	189,934	OR	Situs	59,179	
Distribution Operations	582	3	1,217	SNPD	26.473%	322	
Distribution Operations	583	3	161,279	OR	Situs	34,340	
Distribution Operations	583	3	0	SNPD	26.473%	0	
Distribution Operations	584	3	31	OR	Situs	31	
Distribution Operations	584	3	-	SNPD	26.473%	-	
Distribution Operations	585	3	5,576	SNPD	26.473%	1,476	
Distribution Operations	586	3	39,958	OR	Situs	18,458	
Distribution Operations	586	3	-	SNPD	26.473%	-	
Distribution Operations	587	3	288,809	OR	Situs	98,573	
Distribution Operations	587	3	-	SNPD	26.473%	-	
Distribution Operations	588	3	23,252	OR	Situs	(3,441)	
Distribution Operations	588	3	(141,447)	SNPD	26.473%	(37,445)	
Distribution Operations	589	3	220,246	OR	Situs	132,052	
Distribution Operations	589	3	1,903	SNPD	26.473%	504	
			4,307,357			1,323,756	

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.

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	28,963	OR	Situs	10,164	
Distribution Maintenance	590	3	(2,788)	SNPD	26.473%	(738)	
Distribution Maintenance	591	3	146,493	OR	Situs	41,741	
Distribution Maintenance	591	3	4,945	SNPD	26.473%	1,309	
Distribution Maintenance	592	3	162,579	OR	Situs	60,078	
Distribution Maintenance	592	3	19,019	SNPD	26.473%	5,035	
Distribution Maintenance	593	3	(770,503)	OR	Situs	(1,308,306)	
Distribution Maintenance	593	3	(79,436)	SNPD	26.473%	(21,029)	
Distribution Maintenance	594	3	1,352,799	OR	Situs	267,443	
Distribution Maintenance	594	3	401	SNPD	26.473%	106	
Distribution Maintenance	595	3	-	OR	Situs	-	
Distribution Maintenance	595	3	11,806	SNPD	26.473%	3,125	
Distribution Maintenance	596	3	73,071	OR	Situs	20,627	
Distribution Maintenance	597	3	13,154	OR	Situs	3,407	
Distribution Maintenance	597	3	8,079	SNPD	26.473%	2,139	
Distribution Maintenance	598	3	114,616	OR	Situs	(22,788)	
Distribution Maintenance	598	3	510,978	SNPD	26.473%	135,269	
Customer Accounts Operations	901	3	62	OR	Situs	-	
Customer Accounts Operations	901	3	57,410	CN	30.990%	17,791	
Customer Accounts Operations	902	3	336,764	OR	Situs	91,662	
Customer Accounts Operations	902	3	8,592	CN	30.990%	2,663	
Customer Accounts Operations	903	3	135,339	OR	Situs	45,383	
Customer Accounts Operations	903	3	1,426,201	CN	30.990%	441,979	
Customer Accounts Operations	904	3	1,204,875	OR	Situs	599,706	
Customer Accounts Operations	904	3	14,323	CN	30.990%	4,439	
Customer Accounts Operations	905	3	-	OR	Situs	-	
Customer Accounts Operations	905	3	2,584	CN	30.990%	801	
Customer Service Operations	907	3	4	CN	30.990%	1	
Customer Service Operations	908	3	143,654	OR	Situs	124,202	
Customer Service Operations	908	3	9,796	CN	30.990%	3,036	
Customer Service Operations	908	3	9,443,746	OTHER	0.000%	-	
Customer Service Operations	909	3	189,950	OR	Situs	67,492	
Customer Service Operations	909	3	85,185	CN	30.990%	26,399	
Customer Service Operations	910	3	-	OR	Situs	-	
Customer Service Operations	910	3	164	CN	30.990%	51	
			14,652,825			623,186	

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.

PacifiCorp
Oregon General Rate Case - December 2023
(cont.) O&M Expense Escalation

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
A&G Operations	920	3	(41,808)	OR	Situs	(12,853)	
A&G Operations	920	3	50,175	SO	27.173%	13,634	
A&G Operations	921	3	6,431	CN	30.990%	1,993	
A&G Operations	921	3	172,499	OR	Situs	133,171	
A&G Operations	921	3	456,177	SO	27.173%	123,957	
A&G Operations	922	3	(607,195)	SO	27.173%	(164,994)	
A&G Operations	923	3	46,197	OR	Situs	10,155	
A&G Operations	923	3	1,004,185	SO	27.173%	272,868	
A&G Operations	924	3	-	SO	27.173%	-	
A&G Operations	925	3	-	SO	27.173%	-	
A&G Operations	926	3	(237,120)	SO	27.173%	(64,433)	
A&G Operations	926	3	358,654	OR	Situs	10,382	
A&G Operations	928	3	339,055	SG	26.070%	88,393	
A&G Operations	928	3	-	SO	27.173%	-	
A&G Operations	928	3	146,923	SO	27.173%	39,923	
A&G Operations	928	3	1,325,540	OR	Situs	434,107	
A&G Operations	929	3	(31,248)	SO	27.173%	(8,491)	
A&G Operations	930	3	1,076	OR	Situs	-	
A&G Operations	930	3	-	CN	30.990%	-	
A&G Operations	930	3	-	SG	26.070%	-	
A&G Operations	930	3	86,834	SO	27.173%	23,596	
A&G Operations	931	3	81,828	OR	Situs	36,065	
A&G Operations	931	3	163,396	SO	27.173%	44,400	
A&G Operations	935	3	18,831	OR	Situs	7,028	
A&G Operations	935	3	1,394	CN	30.990%	432	
A&G Operations	935	3	1,210,108	SO	27.173%	328,824	
			4,551,932			1,318,158	
			13,525,091			3,783,013	4.10
			3,840,907			1,026,555	4.10.1
			4,307,357			1,323,756	4.10.2
			14,652,825			623,186	4.10.3
			4,551,932			1,318,158	4.10.4
Total Adjustment			40,878,111			8,074,669	

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.

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 emove Unadjuste ages & Employe Benefits	4.4 Remove Non-Recurring Entries	4.5 Insurance Expense	4.6 Generation Overhaul Expense	4.8 Membership & Subscriptions	4.9 Meals and Entertainment Adjustment	4.11 Wildfire & Veg Management Expenses	4.13 Jim Bridger Units 1 & 2 O&M	5.1 Net Power Costs	8.9 Remove Rolling Hills	8.10 Deer Creek Mine Closure	8.13 Cholla Unit Retirement	O&M Before Escalation	Escalation Percentages	4.10 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	8.20%	1,366,727	18,032,386
	SG	89,370,307	-	(32,788,194)	-	-	-	-	(1,585)	-	-	-	-	(35,379,413)	(14,648,254)	6,552,861	8.20%	537,391	7,090,251
	SNPPS	58,885,776	-	(30,439,434)	-	-	-	-	-	-	-	-	-	-	-	28,446,341	8.20%	2,332,843	30,779,185
	SSECH	264,509	-	-	-	-	-	-	-	-	-	-	-	-	-	264,509	8.20%	21,692	286,201
	SSGCH	7,282,240	-	-	-	-	-	-	(53)	-	-	-	-	-	-	7,282,187	8.20%	597,202	7,879,389
	CA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.20%	-	0
	ID	1,285,707	-	-	-	-	-	-	-	-	-	-	-	-	-	1,285,707	8.20%	105,439	1,391,146
	OR	4,921,418	-	-	-	-	-	-	-	-	-	-	-	-	-	4,921,418	8.20%	403,598	5,325,016
	WA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.20%	-	0
	WYP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.20%	-	0
	Steam Operation Total	852,431,433	-	(63,317,121)	-	-	-	-	(1,638)	-	-	-	-	(35,379,413)	(14,648,254)	739,085,007		5,364,891	744,449,898
Steam Maintenance																			
	SG	32,591,804	-	(10,375,976)	-	-	569,022	-	(22)	-	-	-	-	-	-	22,784,829	7.00%	1,595,310	24,380,139
	SNPPS	105,000,699	-	(38,800,647)	-	-	-	-	-	-	-	-	-	-	-	66,200,052	7.00%	4,635,084	70,835,136
	SSGCH	7,121,369	-	(987)	-	-	-	-	-	-	-	-	-	-	-	7,120,383	7.00%	498,543	7,618,926
	Steam Maintenance Total	144,713,872	-	(49,177,610)	-	-	569,022	-	(22)	-	-	-	-	-	-	96,105,263		6,728,937	102,834,200
Hydro Operations																			
	SG-P	27,122,423	-	(12,249,164)	-	-	-	-	(53)	-	-	-	-	-	-	14,873,206	9.48%	1,410,688	16,283,895
	SG-U	8,563,421	-	(8,344,338)	-	-	-	-	(2,222)	-	-	-	-	-	-	216,861	9.48%	20,569	237,430
	SG	-	-	-	-	-	-	-	53	-	-	-	-	-	-	53	9.48%	5	59
	Hydro Operations Total	35,685,844	-	(20,593,502)	-	-	-	-	(2,221)	-	-	-	-	-	-	15,090,121		1,431,262	16,521,383
Hydro Maintenance																			
	SG-P	6,069,764	-	(2,550,757)	-	-	-	-	-	-	-	-	-	-	-	3,519,007	7.32%	257,467	3,776,474
	SG-U	1,515,303	-	(561,855)	-	-	-	-	-	-	-	-	-	-	-	953,448	7.32%	69,759	1,023,207
	SG	33,000,000	-	-	(33,000,000)	-	-	-	-	-	-	-	-	-	-	-	7.32%	-	0
	Hydro Maintenance Total	40,585,067	-	(3,112,612)	(33,000,000)	-	-	-	-	-	-	-	-	-	-	4,472,455		327,226	4,799,681
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	8.72%	1,010,891	12,597,097
	SNPPO	22,045,619	-	(9,601,596)	-	-	-	-	-	-	-	-	-	-	-	12,444,023	8.72%	1,085,735	13,529,758
	SSGCT	383,214	-	(110,639)	-	-	-	-	-	-	-	-	-	-	-	272,575	8.72%	23,782	296,357
	SE	8,552	-	-	-	-	-	-	-	-	-	-	-	-	-	8,552	8.72%	746	9,298
	SG	35,588,901	(2,509)	(29,273,546)	-	-	-	-	(16,161)	-	-	-	(28,437)	-	-	6,268,247	8.72%	546,902	6,815,149
	ID	3,738,628	-	(69,384)	-	-	-	-	-	-	-	-	-	-	-	3,669,244	8.72%	320,140	3,989,384
	OR	3,460,857	-	(19,124)	-	-	-	-	-	-	-	-	-	-	-	3,441,733	8.72%	300,290	3,742,022
	UT	35,000	-	-	-	-	-	-	-	-	-	-	-	-	-	35,000	8.72%	3,054	38,054
	WYU	54,288	-	-	-	-	-	-	-	-	-	-	-	-	-	54,288	8.72%	4,737	59,025
	Other Operations Total	368,281,143	(2,509)	(39,401,637)	-	-	-	-	(16,161)	-	-	-	(28,437)	-	-	328,832,398		3,296,276	332,128,674
Other Maintenance																			
	SNPPO	8,200,376	-	(2,584,230)	-	-	-	-	-	-	-	-	-	-	-	5,616,147	7.00%	393,064	6,009,210
	SSGCT	363,813	-	(164,782)	-	-	-	-	-	-	-	-	-	-	-	199,031	7.00%	13,930	212,961
	SG	-	-	-	-	-	3,163,574	-	(514)	-	-	-	(1,112,621)	-	-	2,050,439	7.00%	143,506	2,193,945
	SG-W	12,082,666	-	(489,692)	-	-	-	-	-	-	-	-	-	-	-	11,592,974	7.00%	811,371	12,404,344
	Other Maintenance Total	20,646,854	-	(3,238,703)	-	-	3,163,574	-	(514)	-	-	-	(1,112,621)	-	-	19,458,590		1,361,870	20,820,461
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)	4.62%	(48)	(1,083)
	SNPT	37,042,928	-	(21,517,866)	-	-	-	-	-	-	-	-	-	-	-	15,525,062	4.62%	717,936	16,242,998
	Transmission Operations Total	186,409,581	-	(21,517,866)	-	-	-	-	(1,035)	-	-	-	-	-	-	164,890,681		717,888	165,608,569
Transmission Maintenance																			
	SNPT	34,418,467	-	(13,582,092)	-	-	-	-	-	-	-	-	-	-	-	20,836,375	8.36%	1,741,572	22,577,946
	SG	-	-	-	-	-	-	-	(0)	(2,174,016)	-	-	-	-	-	(2,174,016)	8.36%	(181,711)	(2,355,727)
	Transmission Maintenance Total	34,418,467	-	(13,582,092)	-	-	-	-	(0)	(2,174,016)	-	-	-	-	-	18,662,358		1,559,860	20,222,219
Distribution Operations																			
	CA	1,796,696	-	(1,190,497)	-	-	-	-	-	-	-	-	-	-	-	606,199	7.51%	45,552	651,751
	ID	1,672,891	-	(1,199,369)	-	-	-	-	-	-	-	-	-	-	-	473,522	7.51%	35,582	509,105
	OR	12,695,790	-	(8,070,673)	-	-	-	-	(2,728)	-	-	-	-	-	-	4,622,389	7.51%	347,345	4,969,734
	SNPD	21,866,072	-	(23,221,308)	-	-	-	-	(4,937)	-	-	-	-	-	-	(1,360,173)	7.51%	(102,209)	(1,462,382)
	UT	16,073,406	-	(10,701,438)	-	-	-	-	-	-	-	-	-	-	-	5,371,968	7.51%	403,672	5,775,640
	WA	2,872,598	-	(2,071,802)	-	-	-	-	-	-	-	-	-	-	-	800,796	7.51%	60,175	860,971
	WYP	3,119,925	-	(1,985,411)	-	-	-	-	-	-	-	-	-	-	-	1,134,514	7.51%	85,252	1,219,766
	WYU	305,996	-	(175,933)	-	-	-	-	-	-	-	-	-	-	-	130,063	7.51%	9,773	139,837
	Distribution Operations Total	60,403,373	-	(48,616,430)	-	-	-	-	(7,664)	-	-	-	-	-	-	11,779,278		885,143	12,664,422

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 emove Unadjust ages & Employe Benefits	4.4 Remove Non-Recurring Entries	4.5 Insurance Expense	4.6 Generation Overhaul Expense	4.8 Membership & Subscriptions	4.9 Meals and Entertainment Adjustment	4.11 Wildfire & Veg Management Expenses	4.13 Jim Bridger Units 1 & 2 O&M	5.1 Net Power Costs	8.9 Remove Rolling Hills	8.10 Deer Creek Mine Closure	8.13 Cholla Unit Retirement	O&M Before Escalation	Escalation Percentages	4.10 O&M Expense Escalation	O&M After Escalation
Distribution Maintenance																			
	CA	10,043,545	-	(5,634,612)	-	-	-	-	-	-	-	-	-	-	-	4,408,933	8.34%	367,790	4,776,723
	ID	5,669,727	-	(5,542,568)	-	-	-	-	-	-	-	-	-	-	-	127,159	8.34%	10,608	137,766
	OR	66,832,280	-	(35,311,590)	-	-	-	-	0	(42,640,829)	-	-	-	-	-	(11,120,139)	8.34%	(927,634)	(12,047,773)
	SNPD	12,340,220	-	(5,105,331)	-	-	-	-	(17,817)	(1,546,887)	-	-	-	-	-	5,670,185	8.34%	473,003	6,143,188
	UT	53,369,512	-	(37,188,816)	-	-	-	-	-	-	-	-	-	-	-	16,180,696	8.34%	1,349,782	17,530,479
	WA	8,487,156	-	(5,871,447)	-	-	-	-	-	-	-	-	-	-	-	2,615,708	8.34%	218,201	2,833,909
	WYP	9,463,181	-	(8,661,524)	-	-	-	-	-	-	-	-	-	-	-	801,657	8.34%	66,874	868,531
	WYU	1,179,856	-	(753,688)	-	-	-	-	-	-	-	-	-	-	-	426,169	8.34%	35,551	461,720
Distribution Maintenance Total		167,385,477	-	(104,069,575)	-	-	-	-	(17,817)	(44,187,716)	-	-	-	-	-	19,110,370		1,594,174	20,704,543
Customer Accounts Operations																			
	CA	670,321	-	(332,677)	-	-	-	-	-	-	-	-	-	-	-	337,643	10.14%	34,225	371,869
	CN	42,041,620	-	(27,152,867)	-	-	-	-	(840)	-	-	-	-	-	-	14,887,913	10.14%	1,509,111	16,397,024
	ID	2,980,413	-	(1,830,517)	-	-	-	-	-	-	-	-	-	-	-	1,149,895	10.14%	116,559	1,266,454
	OR	8,993,775	(14,359)	(1,711,100)	-	-	-	-	-	-	-	-	-	-	-	7,268,316	10.14%	736,751	8,005,067
	UT	10,517,710	-	(5,497,774)	-	-	-	-	-	-	-	-	-	-	-	5,019,936	10.14%	508,845	5,528,780
	WA	3,171,306	-	(974,198)	-	-	-	-	-	-	-	-	-	-	-	2,197,108	10.14%	222,709	2,419,817
	WYP	1,545,826	-	(1,037,303)	-	-	-	-	-	-	-	-	-	-	-	508,523	10.14%	51,546	560,069
	WYU	259,768	-	(196,588)	-	-	-	-	-	-	-	-	-	-	-	63,180	10.14%	6,404	69,584
Customer Accounts Operations Total		70,180,739	(14,359)	(38,733,025)	-	-	-	-	(840)	-	-	-	-	-	-	31,432,514		3,186,151	34,618,665
Customer Service Operations																			
	CA	130,550	19,017	(27)	-	-	-	-	-	-	-	-	-	-	-	149,540	9.30%	13,911	163,451
	CN	4,707,282	(73,991)	(3,609,350)	-	-	-	-	(1,119)	-	-	-	-	-	-	1,022,821	9.30%	95,150	1,117,972
	ID	125,838	1,052	(14,124)	-	-	-	-	-	-	-	-	-	-	-	112,766	9.30%	10,490	123,256
	OR	4,151,715	45,719	(2,133,756)	-	-	-	-	(3,058)	-	-	-	-	-	-	2,060,619	9.30%	191,694	2,252,313
	OTHER	101,549,342	-	(33,413)	-	-	-	-	-	-	-	-	-	-	-	101,515,929	9.30%	9,443,746	110,959,675
	UT	3,613,822	11,080	(2,846,724)	-	-	-	-	-	-	-	-	-	-	-	778,178	9.30%	72,392	850,570
	WA	459,332	10,746	(319,510)	-	-	-	-	-	-	-	-	-	-	-	150,568	9.30%	14,007	164,575
	WYP	1,291,527	-	(957,109)	-	-	-	-	-	-	-	-	-	-	-	334,418	9.30%	31,110	365,528
	WYU	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.30%	-	0
Customer Service Operations Total		116,029,408	13,622	(9,914,013)	-	-	-	-	(4,178)	-	-	-	-	-	-	106,124,839		9,872,500	115,997,340
A&G Operations & Maintenance																			
	920	78,753,241	-	(78,619,930)	-	-	-	-	-	-	-	-	-	-	-	133,311	6.28%	8,368	141,679
	921	10,663,458	1,284,000	(3,300,981)	-	-	-	-	(9,661)	-	-	-	-	-	-	8,636,816	7.35%	635,107	9,271,923
	922	(37,446,530)	-	27,772,793	-	-	-	-	-	-	-	-	-	-	-	(9,673,738)	6.28%	(607,195)	(10,280,933)
	923	23,768,045	-	-	-	-	-	-	-	-	-	-	-	-	-	23,768,045	4.42%	1,050,382	24,818,427
	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	6.33%	121,534	2,041,046
	928	24,669,376	-	(1,749,228)	-	-	-	-	-	-	-	-	-	-	-	22,920,147	7.90%	1,811,517	24,731,664
	929	(3,457,972)	317	3,391,347	-	-	-	-	-	-	-	-	(431,525)	-	-	(497,833)	6.28%	(31,248)	(529,081)
	930	2,268,077	-	-	-	-	-	(537,249)	-	-	-	-	-	-	-	1,730,828	5.08%	87,911	1,818,738
	931	3,092,716	-	-	-	-	-	-	-	-	-	-	-	-	-	3,092,716	7.93%	245,224	3,337,941
	935	26,538,982	-	(2,088,894)	-	-	-	-	-	-	-	-	-	-	-	24,450,088	5.03%	1,230,333	25,680,420
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		4,551,932	109,324,641
Grand Total		3,092,164,237	1,281,071	(469,869,081)	(33,000,000)	(140,829,653)	3,732,596	(537,249)	(61,751)	(46,361,732)	-	(33,207,191)	(1,572,584)	(32,412,400)	(14,648,254)	2,324,678,009		40,878,111	2,365,556,120
																		Ref 4.10.4	

PacifiCorp
Oregon General Rate Case - December 2023
Escalation Factors

Note: Please see Confidential Exhibit PAC/1005 for details of escalation factors.

	Escalation Factors June 2021 to December 2023	FERC Accounts
STEAM PRODUCTION PLANT		
Operation:	8.20%	500 - 507
Maintenance:	7.00%	510 - 514
HYDRO PRODUCTION PLANT		
Operation:	9.48%	535 - 540
Maintenance:	7.32%	541 - 545
OTHER PRODUCTION PLANT		
Operation:	8.72%	546 - 550; 556 - 557
Maintenance:	7.00%	551 - 554
TRANSMISSION PLANT		
Operation:	4.62%	560 - 567
Maintenance:	8.36%	568 - 573
DISTRIBUTION PLANT		
Operation:	7.51%	580 - 589
Maintenance:	8.34%	590 - 598
CUSTOMER ACCOUNTS		
Operation:	10.14%	901 - 905
CUSTOMER SERVICE and INFORMATION		
Operation:	9.30%	907 - 910
SALES		
Operation:	10.50%	911 - 916
ADMINISTRATIVE and GENERAL		
Operation:	6.28%	920, 922, 929
Operation:	7.35%	921
Operation:	4.42%	923
Operation:	6.33%	926
Operation:	11.69%	927
Operation:	7.90%	928
Operation:	5.08%	930
Operation:	7.93%	931
Maintenance:	5.03%	935

PacifiCorp
Oregon General Rate Case - December 2023
Vegetation & Wildfire Management O&M

	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	26.070%	(566,773)	4.11.1
			(46,361,732)			(43,617,103)	
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	26.070%	863,699	4.11.1
			74,241,037			69,971,978	

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.

PacifiCorp
Oregon General Rate Case - December 2023
Vegetation and Wildfire Management Expenses

Description	Function	FERC	Base Period 12 ME June 2021	Test Period 12 ME Dec 2023
Vegetation Management - Admin	System	593SNPD	1,546,887	2,475,000
Non-WMP Vegetation Management	Distribution	593OR	40,661,656	48,956,097
Non-WMP Vegetation Management	Transmission	571SG	2,124,890	2,688,319
WMP Vegetation Management	Distribution	593OR	1,225,311	15,289,309
WMP Vegetation Management	Transmission	571SG	41,256	476,636
WMP Non-Veg Management	Distribution	593OR	753,862	4,207,676
WMP Non-Veg Management	Transmission	571SG	7,870	148,000
			46,361,732	**74,241,037**

Summary By Function:				**Ref.**
System	593SNPD	1,546,887	2,475,000	4.11
Distribution	593OR	42,640,829	68,453,082	4.11
Transmission	571SG	2,174,016	3,312,955	4.11
		46,361,732	74,241,037	

Description	Function	FERC	Oregon Allocated Base Period 12 ME June 2021	Oregon Allocated Test Period 12 ME Dec 2023
Vegetation Management - Admin	System	593SNPD	409,501	655,197
Non-WMP Vegetation Management	Distribution	593OR	40,661,656	48,956,097
Non-WMP Vegetation Management	Transmission	571SG	553,966	700,854
WMP Vegetation Management	Distribution	593OR	1,225,311	15,289,309
WMP Vegetation Management	Transmission	571SG	10,756	124,261
WMP Non-Veg Management	Distribution	593OR	753,862	4,207,676
WMP Non-Veg Management	Transmission	571SG	2,052	38,584
			43,617,103	**69,971,978**

Oregon-Allocated Expenses By Function:				**Ref.**
System	593SNPD	409,501	655,197	4.11
Distribution	593OR	42,640,829	68,453,082	4.11
Transmission	571SG	566,773	863,699	4.11
		43,617,103	69,971,978	

PacifiCorp
Oregon General Rate Case - December 2023
Transmission Wheeling - Facebook

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Transmission of Electricity by Others	566	3	(4,743,194)	SG	26.070%	(1,236,567)	

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.

PacifiCorp
Oregon General Rate Case December 2023
Transmission Wheeling - Facebook

Note: Please see Confidential Exhibit PAC/1006 for redacted information.

Adjustment Detail:		
Facebook Load @ Input	[redacted]	
Utah Line Loss	5.09%	
Estimated Facebook Load @ Sales	[redacted]	
Average On-Peak and Off-Peak OATT Rate		
Total Transmission Wheeling for Reallocation	4,743,194	Ref. 4.12.1

Tab 5 - Net Power Cost

PacifiCorp
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 Net Power Costs
5.2 BOSR & WRAP Fees

Pacificorp
Oregon General Rate Case - December 2023
Tab 5 Adjustment Summary

	Total Adjustments	5.1 Net Power Costs	5.2 BOSR & WRAP Fees
1 Operating Revenues:			
2 General Business Revenues	-	-	-
3 Interdepartmental	-	-	-
4 Special Sales	40,563,155	40,563,155	-
5 Other Operating Revenues	-	-	-
6 Total Operating Revenues	40,563,155	40,563,155	-
7			
8 Operating Expenses:			
9 Steam Production	(14,027,757)	(14,027,757)	-
10 Nuclear Production	-	-	-
11 Hydro Production	-	-	-
12 Other Power Supply	74,475,770	74,191,604	284,167
13 Transmission	3,021,006	3,021,006	-
14 Distribution	-	-	-
15 Customer Accounting	-	-	-
16 Customer Service & Info	-	-	-
17 Sales	-	-	-
18 Administrative & General	-	-	-
19			
20 Total O&M Expenses	63,469,020	63,184,853	284,167
21			
22 Depreciation	-	-	-
23 Amortization	-	-	-
24 Taxes Other Than Income	-	-	-
25 Income Taxes - Federal	(4,594,138)	(4,537,164)	(56,974)
26 Income Taxes - State	(1,040,445)	(1,027,542)	(12,903)
27 Income Taxes - Def Net	-	-	-
28 Investment Tax Credit Adj.	-	-	-
29 Misc Revenue & Expense	-	-	-
30			
31 Total Operating Expenses:	57,834,436	57,620,147	214,289
32			
33 Operating Rev For Return:	(17,271,281)	(17,056,991)	(214,289)
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	546,651	544,626	2,025
45 Weatherization Loans	-	-	-
46 Misc Rate Base	-	-	-
47			
48 Total Electric Plant:	546,651	544,626	2,025
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:	546,651	544,626	2,025
62			
63 Return on Rate Base	-0.360%	-0.355%	-0.004%
64			
65 Return on Equity	-0.688%	-0.680%	-0.009%
66			
67 TAX CALCULATION:			
68 Operating Revenue	(22,905,864)	(22,621,698)	(284,167)
69 Other Deductions	-	-	-
70 Interest (AFUDC)	-	-	-
71 Interest	11,431	11,388	42
72 Schedule "M" Additions	-	-	-
73 Schedule "M" Deductions	-	-	-
74 Income Before Tax	(22,917,295)	(22,633,086)	(284,209)
75			
76 State Income Taxes	(1,040,445)	(1,027,542)	(12,903)
77 Taxable Income	(21,876,850)	(21,605,544)	(271,306)
78			
79 Federal Income Taxes + Other	(4,594,138)	(4,537,164)	(56,974)
APPROXIMATE PRICE CHANGE	23,732,287	23,438,304	293,982

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	6,189,133	SG	26.070%	1,613,528	5.1.1
Existing Firm UPL	447NPC	3	-	SG	26.070%	-	5.1.1
Post-Merger Firm	447NPC	3	145,837,137	SG	26.070%	38,020,240	5.1.1
Non-Firm	447NPC	3	3,707,443	SE	25.068%	929,387	5.1.1
Total Sales for Resale			155,733,713			40,563,155	
Adjustment to Expense:							
Purchased Power (Account 555)							
Existing Firm Demand PPL	555NPC	3	8,295,068	SG	26.070%	2,162,553	5.1.1
Existing Firm Demand UPL	555NPC	3	11,456,377	SG	26.070%	2,986,717	5.1.1
Existing Firm Energy	555NPC	3	44,724,911	SE	25.068%	11,211,701	5.1.1
Post-merger Firm	555NPC	3	298,036,729	SG	26.070%	77,699,195	5.1.1
Post-merger Firm - Situs	555NPC	3	(10,277,762)	UT	Situs	-	5.1.1
Secondary Purchases	555NPC	3	(62,781,784)	SE	25.068%	(15,738,222)	5.1.1
Seasonal Contracts	555NPC	3		SG	26.070%	-	5.1.1
Other Generation	555NPC	3		SG	26.070%	-	5.1.1
Total Purchased Power Adjustments:			289,453,539			78,321,943	
Wheeling Expense (Account 565)							
Existing Firm PPL	565NPC	3	23,886,724	SG	26.070%	6,227,351	5.1.1
Existing Firm UPL	565NPC	3	-	SG	26.070%	-	5.1.1
Post-merger Firm	565NPC	3	(8,853,324)	SG	26.070%	(2,308,092)	5.1.1
Non-Firm	565NPC	3	(3,583,246)	SE	25.068%	(898,253)	5.1.1
Total Wheeling Expense Adjustments:			11,450,154			3,021,006	
Fuel Expense (Accounts 501, 503, 547)							
Fuel - Overburden Amortization - Idaho	501NPC	3	(35,987)	ID	Situs	-	5.1.1
Fuel - Overburden Amortization - Wyoming	501NPC	3	(101,258)	WYP	Situs	-	5.1.1
Fuel Consumed - Coal	501NPC	3	(19,138,275)	SE	25.068%	(4,797,609)	5.1.1
Fuel Consumed - Gas	501NPC	3	(5,143,679)	SE	25.068%	(1,289,424)	5.1.1
Steam from Other Sources	503NPC	3	(635,805)	SE	25.068%	(159,385)	5.1.1
Natural Gas Consumed	547NPC	3	12,287,901	SE	25.068%	3,080,348	5.1.1
Simple Cycle Combustion Turbines	547NPC	3	7,486,648	SE	25.068%	1,876,763	5.1.1
Cholla / APS Exchange	501NPC	3	(31,040,758)	SE	25.068%	(7,781,339)	5.1.1
Total Fuel Expense Adjustments:			(36,321,213)			(9,070,646)	
Total Power Cost Adjustment			108,848,767			31,709,147	
Post-merger Firm Type 1	555NPC	1	(33,207,191)	SG	26.070%	(8,657,228)	5.1.1
Oregon Solar Project	555NPC	3	(430,221)	OR	Situs	(430,221)	5.1.4

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 Aurora 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	-	-	-	-	-	6,189,133	6,189,133	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	349,419,847	145,837,137	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	355,608,980	155,733,713	
Purchased Power (Account 555)									
Existing Firm Demand PPL	555.66	-	-	-	-	-	8,295,068	8,295,068	SG
Existing Firm Demand UPL	555.68	-	-	-	-	-	11,456,377	11,456,377	SG
Existing Firm Energy	555.65, 555.69	-	-	-	-	-	44,724,911	44,724,911	SE
Post-merger Firm	555.26, .55, .59, .61, .62, .63, .64, .67, .8	621,018,560	-	621,018,560	-	621,018,560	885,848,099	264,829,538	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	950,324,455	289,453,539	
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	12,388,361	(3,583,246)	SE
Total Wheeling Expense Adjustment		149,366,653	-	149,366,653	-	149,366,653	160,816,807	11,450,154	
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	599,969,137	(19,138,275)	SE
Fuel Consumed - Gas	501.35	18,260,998	-	18,260,998	-	18,260,998	13,117,319	(5,143,679)	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	301,360,345	12,287,901	SE
Simple Cycle Combustion Turbines	547.1	1,980,087	-	1,980,087	-	1,980,087	9,466,735	7,486,648	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	928,397,642	(36,321,213)	
Net Power Cost		**1,623,065,242**	**(14,776,894)**	**1,608,288,348**	**(33,207,191)**	**1,575,081,157**	**1,683,929,924**	**108,848,767**	
					Ref 5.1		**Ref 5.1.3**	**Ref 5.1**	

PacifiCorp
Oregon General Rate Case - December 2023
Net Power Cost Study

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	6,189,133	6,189,133			
Post Merger	349,419,847				349,419,847
Utah Pre Merger	-	-			
NonFirm Sub Total	-			-	
TOTAL SPECIAL SALES	355,608,980	6,189,133	-	-	349,419,847
PURCHASED POWER & NET INTERCHANGE					
BPA Peak Purchase	-	-			
Pacific Capacity	-	-	-		
Mid Columbia	2,265,569	679,671	1,585,898		
Misc/Pacific	154,785	32,097	122,688		
Q.F. Contracts/PPL	-	7,583,300	36,946,945		102,499,061
Small Purchases west	-		-		
Pacific Sub Total	2,420,354	8,295,068	38,655,531	-	102,499,061
Gemstate	1,145,216		1,145,216		
GSLM	-		-		
QF Contracts/UPL	-	11,456,377	4,909,876		163,582,622
IPP Layoff	-	-	-		
Small Purchases east	14,288		14,288		
UP&L to PP&L	-	-	-		
Utah Sub Total	1,159,504	11,456,377	6,069,380	-	163,582,622
APS Supplemental	-				-
Avoided Cost Resource	-				-
Appaloosa 1A Solar	1,565,395				1,565,395
Appaloosa 1B Solar	1,043,597				1,043,597
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	35,399,601				35,399,601
Eagle Mountain - UAMPS/UMPA	-				-
Elektron Solar 20 yr	797,568				797,568
Elektron Solar 25yr	5,433,412				5,433,412
Horseshoe Solar	5,348,701				5,348,701
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
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	5,701,664				5,701,664
Skysol Solar	9,192,400				9,192,400
Soda Lake Geothermal	-				-
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	(15,944,747)				(15,944,747)

	Merged 1/2023 - 12/2023	Pre-Merger Demand	Pre-Merger Energy	Non-Firm	Post-Merger
SPECIAL SALES FOR RESALE					
Pacific Pre Merger	6,189,133	6,189,133			
Seasonal Purchased Power					
Constellation 2013-2016	-				-
Short Term Firm Purchases	397,201,954				397,201,954
New Firm Sub Total	619,766,416	-	-	-	619,766,416
Integration Charge	-				-
Non Firm Sub Total	-			-	
TOTAL PURCHASED PW & NET INT.	623,346,275	19,751,445	44,724,911	-	885,848,099
WHEELING & U. OF F. EXPENSE					
Pacific Firm Wheeling and Use of Facilities	23,886,724	23,886,724			
Utah Firm Wheeling and Use of Facilities	-	-			
Post Merger	124,541,723				124,541,723
Nonfirm Wheeling	12,388,361			12,388,361	
TOTAL WHEELING & U. OF F. EXPENSE	160,816,807	23,886,724	-	12,388,361	124,541,723
THERMAL FUEL BURN EXPENSE					
Carbon	-			-	
Cholla	-			-	
Colstrip	18,388,036			18,388,036	
Craig	14,393,703			14,393,703	
Chehalis	60,877,049			60,877,049	
Currant Creek	55,731,824			55,731,824	
Dave Johnston	63,751,340			63,751,340	
Gadsby	13,117,319			13,117,319	
Gadsby CT	9,466,735			9,466,735	
Hayden	10,169,525			10,169,525	
Hermiston	28,824,508			28,824,508	
Hunter	126,226,934			126,226,934	
Huntington	110,658,947			110,658,947	
Jim Bridger	196,125,182			196,125,182	
Lake Side 1	68,555,547			68,555,547	
Lake Side 2	50,258,935			50,258,935	
Naughton - Gas	20,696,079			20,696,079	
Naughton	27,974,534			27,974,534	
Wyodak	32,280,937			32,280,937	
Gas Physical	(6,259,946)			(6,259,946)	
Gas Swaps	(17,010,410)			(17,010,410)	
Clay Basin Gas Storage	(452,163)			(452,163)	
Pipeline Reservation Fees	40,138,923			40,138,923	
TOTAL FUEL BURN EXPENSE	923,913,535	-	-	923,913,535	-
OTHER GENERATION EXPENSE					
Blundell	4,484,106			4,484,106	
TOTAL OTHER GEN. EXPENSE	4,484,106	-	-	4,484,106	-
NET POWER COST	**1,683,929,924**	37,449,035	44,724,911	940,786,003	660,969,975
	Ref 5.1.1				

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	**17,320**	(4,003)	219	12,573	44,877	61,801	72,310	(62,349)	(89,397)	(41,864)	16,543	6,748	(139)
REP Adjustments (Total Company)	**(1,794,801)**	(96,427)	(94,986)	(106,988)	(123,482)	(200,250)	(252,202)	(184,018)	(143,309)	(127,841)	(161,091)	(137,569)	(166,637)
Allocated on SG Factor (26.070%)	**(467,911)**	(25,139)	(24,763)	(27,892)	(32,192)	(52,206)	(65,750)	(47,974)	(37,361)	(33,329)	(41,997)	(35,865)	(43,443)
REP Adjustments (Oregon Allocation)	**20,370**	(271)	268	1,915	2,914	4,898	4,018	(3,595)	(6,015)	(2,756)	87	332	18,577
Total OR Situs Adjustment	**(430,221)**	(29,413)	(24,276)	(13,404)	15,599	14,493	10,578	(113,918)	(132,774)	(77,949)	(25,367)	(28,785)	(25,005)

PacifiCorp
Oregon General Rate Case - December 2023
BSOR & WRAP Fees

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
BOSR Fee	557	3	90,000	SG	26.070%	23,463	5.2.1
WRAP Fee	557	3	1,000,000	SG	26.070%	260,703	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.

PacifiCorp
Oregon General Rate Case - December 2023
BOSR & WRAP Fees

Incremental O&M	CY 2023 Amount	
EIM Board of State Regulators	$ 90,000	
Western Resource Adequacy Program	$ 1,000,000	
	$ 1,090,000	**Ref 5.2**

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 Depreciation & Amortization Expense
6.2 Depreciation & Amortization Reserve
6.3 Depreciation Allocation Correction
6.4 Repowering Buy Downs
6.5 Coal Depreciable Life Update
6.6 Bridger Coal Reclamation Costs

Pacificorp
Oregon General Rate Case - December 2023
Tab 6 Adjustment Summary

		Total Adjustments	6.1 Depreciation & Amortiation Expense	6.2 Depreciation & Amortization Reserve	6.3 Depreciation Allocation Correction	6.4 Repowering Buy Downs	6.5 Coal Depreciable Life Update	6.6 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	3,634,603	-	-	-	-	-	3,634,603
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	3,634,603	-	-	-	-	-	3,634,603
21								
22	Depreciation	58,506,685	59,684,178	-	(366,971)	-	(810,523)	-
23	Amortization	24,557,686	1,784,744	-	-	22,772,942	-	-
24	Taxes Other Than Income	-	-	-	-	-	-	-
25	Income Taxes - Federal	(13,912,304)	(12,321,830)	2,456,319	73,562	(4,466,013)	322,832	22,826
26	Income Taxes - State	(3,150,752)	(2,790,553)	556,288	16,660	(1,011,428)	73,113	5,170
27	Income Taxes - Def Net	(259,669)	-	-	-	833,235	(199,280)	(893,624)
28	Investment Tax Credit Adj.	-	-	-	-	-	-	-
29	Misc Revenue & Expense	-	-	-	-	-	-	-
30								
31	Total Operating Expenses:	69,376,249	46,356,538	3,012,607	(276,749)	18,128,736	(613,858)	2,768,975
32								
33	Operating Rev For Return:	(69,376,249)	(46,356,538)	(3,012,607)	276,749	(18,128,736)	613,858	(2,768,975)
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	(126,926)	(142,842)	28,475	853	(51,773)	3,742	34,619
45	Weatherization Loans	-	-	-	-	-	-	-
46	Misc Rate Base	-	-	-	-	-	-	-
47								
48	Total Electric Plant:	(126,926)	(142,842)	28,475	853	(51,773)	3,742	34,619
49		-	-	-	-	-	-	-
50	Rate Base Deductions:	-	-	-	-	-	-	-
51	Accum Prov For Deprec	(752,230,479)	-	(569,440,273)	-	(183,195,467)	405,261	-
52	Accum Prov For Amort	(16,574,495)	-	(16,574,495)	-	-	-	-
53	Accum Def Income Tax	(602,563)	-	-	-	(2,488,860)	99,640	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	(776,674,325)	-	(586,014,768)	-	(185,684,327)	504,901	(5,480,132)
60								
61	Total Rate Base:	(776,801,251)	(142,842)	(585,986,293)	853	(185,736,099)	508,644	(5,445,513)
62								
63	Return on Rate Base	-0.735%	-0.964%	0.505%	0.007%	-0.234%	0.015%	-0.063%
64								
65	Return on Equity	-1.406%	-1.844%	0.966%	0.013%	-0.449%	0.028%	-0.120%
66								
67	TAX CALCULATION:							
68	Operating Revenue	(86,698,974)	(61,468,922)	-	366,971	(22,772,942)	810,523	(3,634,603)
69	Other Deductions	-	-	-	-	-	-	-
70	Interest (AFUDC)	-	-	-	-	-	-	-
71	Interest	(16,243,007)	(2,987)	(12,253,044)	18	(3,883,764)	10,636	(113,866)
72	Schedule "M" Additions	1,056,147	-	-	-	(3,388,979)	810,523	3,634,603
73	Schedule "M" Deductions	-	-	-	-	-	-	-
74	Income Before Tax	(69,399,819)	(61,465,935)	12,253,044	366,953	(22,278,157)	1,610,410	113,866
75								
76	State Income Taxes	(3,150,752)	(2,790,553)	556,288	16,660	(1,011,428)	73,113	5,170
77	Taxable Income	(66,249,067)	(58,675,382)	11,696,756	350,293	(21,266,728)	1,537,297	108,697
78								
79	Federal Income Taxes + Other	(13,912,304)	(12,321,830)	2,456,319	73,562	(4,466,013)	322,832	22,826
	APPROXIMATE PRICE CHANGE	18,304,908	63,538,838	(53,809,936)	(379,328)	6,488,893	(791,282)	3,257,722

PacifiCorp
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:							
Steam Depreciation Expense	403SP	3	26,840,673	SG	26.070%	6,997,455	
Steam Depreciation Expense	403SP	3	19,020,532	SG	26.070%	4,958,718	
Steam Depreciation Expense	403SP	3	118,268,095	SG	26.070%	30,832,897	
Steam Depreciation Expense	403SP	3	(7,589,695)	SG	26.070%	(1,978,660)	
Hydro Depreciation Expense	403HP	3	28,228,285	SG-P	26.070%	7,359,210	
Hydro Depreciation Expense	403HP	3	(99,213)	SG-U	26.070%	(25,865)	
Hydro Depreciation Expense	403HP	3	(25,970,964)	SG-P	26.070%	(6,770,719)	
Hydro Depreciation Expense	403HP	3	1,945,365	SG-U	26.070%	507,163	
Other Depreciation Expense	403OP	3	-	SG	26.070%	-	
Other Depreciation Expense	403OP	3	2,570,714	SG	26.070%	670,194	
Other Depreciation Expense	403OP	3	39,134,400	SG-W	26.070%	10,202,472	
Other Depreciation Expense	403OP	3	-	OR	Situs	-	
Other Depreciation Expense	403OP	3	624,964	SG	26.070%	162,930	
Transmission Depreciation Expense	403TP	3	(353,434)	SG	26.070%	(92,141)	
Transmission Depreciation Expense	403TP	3	(318,735)	SG	26.070%	(83,095)	
Transmission Depreciation Expense	403TP	3	13,515,484	SG	26.070%	3,523,533	
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	26.070%	(623)	
General Depreciation Expense	403GP	3	(23,398)	SG	26.070%	(6,100)	
General Depreciation Expense	403GP	3	603,633	SG	26.070%	157,369	
General Depreciation Expense	403GP	3	6,592,574	SO	27.173%	1,791,406	
General Depreciation Expense	403GP	3	(66,807)	SG	26.070%	(17,417)	
General Depreciation Expense	403GP	3	701	SG	26.070%	183	
General Depreciation Expense	403GP	3	(43,613)	CN	30.990%	(13,516)	
General Depreciation Expense	403GP	3	2,511	SE	25.068%	629	
			252,925,826			59,684,178	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.

PacifiCorp PAGE 6.1.1
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	26.070%	(436)	
Intangible Amortization	404IP	3	(78,646)	SG	26.070%	(20,503)	
Intangible Amortization	404IP	3	(8)	ID	Situs	-	
Intangible Amortization	404IP	3	2	OR	Situs	2	
Intangible Amortization	404IP	3	(14,686)	SE	25.068%	(3,682)	
Intangible Amortization	404IP	3	(8,908,817)	SG	26.070%	(2,322,559)	
Intangible Amortization	404IP	3	(14,435)	SG-P	26.070%	(3,763)	
Intangible Amortization	404IP	3	21,234	SG-U	26.070%	5,536	
Intangible Amortization	404IP	3	(13,762)	SG	26.070%	(3,588)	
Intangible Amortization	404IP	3	14,942,879	SO	27.173%	4,060,441	
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	26.070%	-	
Hydro Amortization	404HP	3	0	SG-P	26.070%	0	
Hydro Amortization	404HP	3	-	SG-U	26.070%	-	
Other Amortization	404OP	3	-	SG	26.070%	-	
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	27.173%	(37,729)	
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			1,784,744	6.1.5

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.

PacifiCorp
Oregon General Rate Case - December 2023
Depreciation and Amortization Expense Summary

Description	Account	Factor	12 ME Jun 2021 Expense	Test Period Expense	Adjustment to Test Period
DEPRECIATION EXPENSE					
Steam Production Plant:					
Pre-merger Pacific	403SP	SG	40,420,413	67,261,085	26,840,673
Pre-merger Utah	403SP	SG	33,611,594	52,632,126	19,020,532
Post-merger	403SP	SG	223,954,796	342,222,891	118,268,095
Post-merger	403SP	SG	7,589,695	-	(7,589,695)
Total Steam Plant			305,576,498	462,116,102	156,539,604
Hydro Production Plant:					
Pre-merger Pacific	403HP	SG-P	(24,185,191)	4,043,093	28,228,285
Pre-merger Utah	403HP	SG-U	1,348,641	1,249,428	(99,213)
Post-merger	403HP	SG-P	47,425,286	21,454,323	(25,970,964)
Post-merger	403HP	SG-U	6,654,516	8,599,880	1,945,365
Total Hydro Plant			31,243,252	35,346,724	4,103,473
Other Production Plant:					
Pre-merger Utah	403OP	SG	-	-	-
Post-merger	403OP	SG	65,951,638	68,522,352	2,570,714
Post-merger Wind	403OP	SG-W	97,958,758	137,093,159	39,134,400
Post-merger Wind	403OP	OR	-	-	-
Post-merger	403OP	SG	3,697,797	4,322,762	624,964
Total Other Production Plant			167,608,194	209,938,272	42,330,078
Transmission Plant:					
Pre-merger Pacific	403TP	SG	8,458,141	8,104,707	(353,434)
Pre-merger Utah	403TP	SG	10,613,292	10,294,556	(318,735)
Post-merger	403TP	SG	106,315,401	119,830,885	13,515,484
Total Transmission Plant			125,386,834	138,230,148	12,843,315
Distribution Plant:					
California	403364	CA	7,856,350	9,254,102	1,397,752
Oregon	403364	OR	55,521,949	56,428,045	906,096
Washington	403364	WA	15,183,453	16,032,588	849,135
Eastern Wyoming	403364	WYP	18,117,193	19,227,174	1,109,981
Utah	403364	UT	72,275,031	93,266,338	20,991,307
Idaho	403364	ID	8,951,667	11,380,194	2,428,527
Western Wyoming	403364	WYU	3,785,512	4,144,520	359,008
Total Distribution Plant			181,691,155	209,732,961	28,041,805
General Plant:					
California	403GP	CA	429,862	474,036	44,174
Oregon	403GP	OR	5,548,245	6,150,304	602,059
Washington	403GP	WA	1,100,960	1,117,620	16,660
Eastern Wyoming	403GP	WYP	1,986,530	2,256,466	269,935
Utah	403GP	UT	5,162,843	6,150,804	987,962
Idaho	403GP	ID	988,458	1,092,107	103,649
Western Wyoming	403GP	WYU	404,794	384,695	(20,100)
Pre-merger Pacific	403GP	SG	18,231	15,841	(2,389)
Pre-merger Utah	403GP	SG	51,315	27,917	(23,398)
Post-merger	403GP	SG	10,111,049	10,714,682	603,633
General Office	403GP	SO	16,310,325	22,902,899	6,592,574
General Office	403GP	SG	66,807	-	(66,807)
General Office	403GP	SG	8,187	8,888	701
Customer Service	403GP	CN	966,692	923,079	(43,613)
Fuel Related	403GP	SE	108,300	110,810	2,511
Total General Plant			43,262,598	52,330,149	9,067,551
Total Depreciation Expense			854,768,531	1,107,694,357	**252,925,826**
					Ref 6.1

PacifiCorp
Oregon General Rate Case - December 2023
Depreciation and Amortization Expense Summary

Description	Account	Factor	12 ME Jun 2021 Expense	Test Period Expense	Adjustment to Test Period
AMORTIZATION EXPENSE					
Intangible Plant:					
California	404IP	CA	1,765	1,765	-
Customer Service	404IP	CN	13,528,148	13,792,251	264,103
Pre-merger Utah	404IP	SG	14,143	12,470	(1,673)
Pre-merger Pacific	404IP	SG	78,646	-	(78,646)
Idaho	404IP	ID	23,042	23,033	(8)
Oregon	404IP	OR	11,685	11,687	2
Fuel Related	404IP	SE	1,821	(12,865)	(14,686)
Post-merger	404IP	SG	16,038,025	7,129,208	(8,908,817)
Hydro Relicensing	404IP	SG-P	2,694,702	2,680,267	(14,435)
Hydro Relicensing	404IP	SG-U	293,112	314,346	21,234
Post-merger	404IP	SG	13,762	-	(13,762)
General Office	404IP	SO	14,405,872	29,348,751	14,942,879
Utah	404IP	UT	37,828	38,802	974
Washington	404IP	WA	3,133	3,148	16
Eastern Wyoming	404IP	WYP	110,823	108,401	(2,422)
Western Wyoming	404IP	WYU	-	-	-
Total Intangible Plant			47,256,507	53,451,266	6,194,759
Hydro Production Plant:					
Pre-merger Pacific	404HP	SG	-	-	-
Post-merger	404HP	SG-P	311,696	311,696	0
Post-merger	404HP	SG-U	-	-	-
Total Hydro Plant			311,696	311,696	0
Other Production Plant:					
Post-merger	404OP	SG	-	-	-
Total Other Plant			-	-	-
General Plant:					
California	404GP	CA	20	-	(20)
General Office	404GP	CN	-	-	-
Oregon	404GP	OR	293,726	322,905	29,179
General Office	404GP	SO	247,138	108,292	(138,845)
Utah	404GP	UT	832	-	(832)
Washington	404GP	WA	92,604	96,268	3,665
Eastern Wyoming	404GP	WYP	53,169	53,169	0
Western Wyoming	404GP	WYU	-	-	-
Total General Plant			687,488	580,634	(106,854)
Total Amortization			48,255,690	54,343,596	**6,087,906**
					Ref 6.1.1
Total Depreciation and Amortization			903,024,221	1,162,037,953	259,013,732
				Ref. 6.1.13	

PacifiCorp
Oregon General Rate Case - December 2023
Jun 2021 - Dec 2022 Depreciation & Amortization Expense

Description	Factor	2018 Rate	Adjusted EPIS Balance Jun 2021	Depreciation Expense Jun 2021	Adjustments	Adjusted EPIS Balance Jul 2021	Depreciation Expense Jul 2021	Adjustments	Adjusted EPIS Balance Aug 2021	Depreciation Expense Aug 2021	Adjustments	Adjusted EPIS Balance Sep 2021	Depreciation Expense Sep 2021	Adjustments	Adjusted EPIS Balance Oct 2021	Depreciation Expense Oct 2021
DEPRECIATION EXPENSE																
Steam Production Plant:																
Pre-merger Pacific	SG	6.692%	1,012,491,439	5,646,445	(411,968)	1,012,079,471	5,645,296	(411,968)	1,011,667,503	5,642,998	(411,968)	1,011,255,535	5,640,701	(411,968)	1,010,843,566	5,638,404
Pre-merger Utah	SG	5.015%	1,059,174,518	4,426,524	(538,554)	1,058,635,963	4,425,398	(538,554)	1,058,097,409	4,423,148	(538,554)	1,057,558,855	4,420,897	(538,554)	1,057,020,301	4,418,646
Post-merger	SG	6.992%	4,781,690,336	27,861,819	(1,451,787)	4,780,238,549	27,857,590	(745,709)	4,779,492,840	27,851,187	(2,698,237)	4,776,794,603	27,841,154	10,783,833	4,787,578,436	27,864,710
Geothermal - Blundell	SG	6.992%	29,402,029	171,319	-	29,402,029	171,319	-	29,402,029	171,319	-	29,402,029	171,319	-	29,402,029	171,319
Carbon	SG															
Pollution Control Equipment	SG	6.992%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pollution Control Equipment	SG	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG	0.000%	1,266,851	-	-	1,266,851	-	-	1,266,851	-	-	1,266,851	-	-	1,266,851	-
Total Steam Plant			6,884,025,173	38,106,107	(2,402,310)	6,881,622,863	38,099,602.79	(1,696,232)	6,879,926,632	38,088,652.44	(3,648,759)	6,876,277,873	38,074,070.70	9,833,310	6,886,111,183	38,093,078.97
Hydro Production Plant:																
Pre-merger Pacific	SG	2.210%	183,823,226	338,586	(50,121)	183,773,105	338,540	(50,121)	183,722,984	338,448	(50,121)	183,672,864	338,355	(50,121)	183,622,743	338,263
Pre-merger Utah	SG	3.181%	39,865,127	105,687	(32,867)	39,832,260	105,644	(32,867)	39,799,393	105,557	(32,867)	39,766,526	105,470	(32,867)	39,733,659	105,382
Post-merger	SG-P	2.741%	635,303,685	1,450,889	(504,594)	634,799,091	1,450,313	(151,342)	634,647,749	1,449,564	1,089,753	635,737,502	1,450,636	1,777,547	637,515,049	1,453,910
Post-merger	SG-U	4.692%	152,896,613	597,831	169,637	153,066,250	598,163	(106,448)	152,959,802	598,286	496,010	153,455,812	599,048	227,989	153,683,801	600,463
Klamath - New Capital	SG-P	20.000%	2,703,876	45,065	-	2,703,876	45,065	-	2,703,876	45,065	281,024	2,984,900	47,406	73,294	3,058,193	50,359
Klamath		0.000%	91,504,591	-	-	91,504,591	-	-	91,504,591	-	-	91,504,591	-	-	91,504,591	-
Total Hydro Plant			1,106,097,117	2,538,059	(417,944)	1,105,679,172	2,537,724	(340,777)	1,105,338,395	2,536,919	1,783,800	1,107,122,194	2,540,915	1,995,842	1,109,118,036	2,548,378
Other Production Plant:																
Pre-merger Utah	SG	0.000%	235,129	-	-	235,129	-	-	235,129	-	-	235,129	-	-	235,129	-
Post-merger	SG	3.503%	1,925,969,509	5,622,163	(2,125,742)	1,923,843,767	5,619,061	(1,934,710)	1,921,909,056	5,613,134	(2,138,184)	1,919,770,872	5,607,190	26,545,686	1,946,316,558	5,642,814
Post-merger Wind	SG-W	4.223%	3,160,796,216	11,123,277	30,038,624	3,190,834,840	11,176,132	6,448,004	3,197,282,844	11,240,332	11,542,859	3,208,825,703	11,271,989	18,837,113	3,227,662,816	11,325,444
Black Cap Solar	OR	0.000%	74,986		-	74,986		-	74,986		-	74,986		-	74,986	
Post-merger	SG	4.825%	85,640,221	344,357	1,270,934	86,911,154	346,912	(39,401)	86,871,753	349,388	3,255,170	90,126,924	355,853	(39,401)	90,087,523	362,318
Total Other Plant			5,172,716,061	17,089,797	29,183,815	5,201,899,876	17,142,104.22	4,473,893	5,206,373,769	17,202,854.43	12,659,845	5,219,033,614	17,235,031.18	45,343,398	5,264,377,012	17,330,576.47
Transmission Plant:																
Pre-merger Pacific	SG	1.700%	479,801,515	679,681	(168,182)	479,633,333	679,562	(168,182)	479,465,150	679,323	(168,182)	479,296,968	679,085	(168,182)	479,128,786	678,847
Pre-merger Utah	SG	1.673%	620,673,594	865,294	(295,470)	620,378,125	865,088	(295,470)	620,082,655	864,676	(295,470)	619,787,185	864,264	(295,470)	619,491,716	863,853
Post-merger	SG	1.724%	6,545,677,086	9,402,321	10,333,361	6,556,010,447	9,409,743	(673,090)	6,555,337,357	9,416,681	17,630,223	6,572,967,580	9,428,859	39,607,968	6,612,575,548	9,469,968
Total Transmission Plant			7,646,152,195	10,947,296	9,869,709	7,656,021,904	10,954,392.36	(1,136,742)	7,654,885,162	10,960,680.28	17,166,571	7,672,051,734	10,972,208.87	39,144,316	7,711,196,050	11,012,667.66
Distribution Plant:																
California	CA	2.704%	290,384,821	654,408	499,707	290,884,529	654,971	390,472	291,275,000	655,974	1,454,890	292,729,890	658,053	1,048,077	293,777,967	660,874
Oregon	OR	2.271%	2,324,681,909	4,400,159	3,519,013	2,328,200,922	4,403,489	3,650,659	2,331,851,581	4,410,274	15,160,933	2,347,012,514	4,428,078	4,026,463	2,351,038,977	4,446,237
Washington	WA	2.588%	571,387,038	1,232,462	1,855,530	573,242,568	1,234,463	1,253,696	574,496,264	1,237,816	1,410,468	575,906,732	1,240,690	935,329	576,842,061	1,243,220
Eastern Wyoming	WYP	2.685%	672,061,808	1,503,917	2,076,156	674,137,963	1,506,240	1,281,841	675,419,805	1,509,997	2,349,680	677,769,484	1,514,061	2,018,870	679,788,354	1,518,948
Utah	UT	2.540%	3,342,346,441	7,075,743	13,672,154	3,356,018,595	7,090,215	7,135,560	3,363,154,155	7,112,240	22,777,006	3,385,931,161	7,143,903	21,241,539	3,407,172,700	7,190,496
Idaho	ID	2.561%	397,879,329	849,182	836,267	398,715,596	850,074	991,986	399,707,583	852,025	2,276,625	401,984,208	855,513	3,509,907	405,494,115	861,688
Western Wyoming	WYU	2.682%	155,050,984	346,494	(27,785)	155,023,199	346,463	(27,785)	154,995,414	346,401	(27,785)	154,967,630	346,339	(27,785)	154,939,845	346,277
Total Distribution Plant			7,753,792,330	16,062,365	22,431,042	7,776,223,372	16,085,916.17	14,676,430	7,790,899,802	16,124,728.90	45,401,816	7,836,301,618	16,186,636.43	32,752,400	7,869,054,018	16,267,740.03
General Plant:																
California	CA	2.021%	22,604,813	38,072	(36,203)	22,568,610	38,041	(23,819)	22,544,791	37,991	(24,813)	22,519,978	37,950	27,109	22,547,087	37,952
Oregon	OR	2.577%	219,239,049	470,803	(183,854)	219,055,195	470,606	(157,612)	218,897,583	470,239	607,696	219,505,279	470,723	1,150,595	220,655,874	472,610
Washington	WA	2.371%	46,321,284	91,537	(96,795)	46,224,489	91,441	(118,679)	46,105,810	91,228	194,692	46,300,502	91,303	76,298	46,376,800	91,571
Eastern Wyoming	WYP	2.539%	80,936,320	171,242	(229,229)	80,707,091	171,000	(42,937)	80,664,154	170,712	348,900	81,013,054	171,035	480,034	81,493,088	171,912
Utah	UT	2.215%	237,718,891	438,760	64,960	237,783,851	438,820	1,991,241	239,775,092	440,718	723,655	240,498,747	443,223	2,718,045	243,216,792	446,399
Idaho	ID	1.990%	51,387,414	85,209	(47,717)	51,339,697	85,170	(24,323)	51,315,374	85,110	96,988	51,412,362	85,170	300,719	51,713,081	85,500
Western Wyoming	WYU	2.182%	18,200,958	33,096	(31,708)	18,169,250	33,067	(31,708)	18,137,543	33,009	(31,708)	18,105,835	32,952	(31,708)	18,074,128	32,894
Pre-merger Pacific	SG	2.093%	1,007,315	1,757	(13,917)	993,398	1,745	(13,917)	979,480	1,721	(13,917)	965,563	1,696	(13,917)	951,646	1,672
Pre-merger Utah	SG	1.231%	2,821,996	2,895	(30,778)	2,791,218	2,879	(30,778)	2,760,439	2,847	(30,778)	2,729,661	2,816	(30,778)	2,698,882	2,784
Post-merger	SG	3.438%	302,412,630	866,305	(300,976)	302,111,654	865,874	(282,844)	301,828,810	865,038	(462,012)	301,366,798	863,971	26,318	301,393,117	863,347
General Office	SO	5.656%	349,037,338	1,645,217	(561,391)	348,475,947	1,643,894	201,323	348,677,270	1,643,046	4,910,321	353,587,591	1,655,093	23,430,785	377,018,376	1,721,887
General Office	SG	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
General Office	SG	3.982%	223,232	741	-	223,232	741	-	223,232	741	-	223,232	741	-	223,232	741
Customer Service	CN	5.953%	17,295,589	85,802	(99,428)	17,196,160	85,555	(99,428)	17,096,732	85,062	(99,428)	16,997,303	84,569	(99,428)	16,897,875	84,075
Fuel Related	SE	3.632%	3,318,698	10,046	(14,898)	3,303,800	10,023	(14,898)	3,288,902	9,978	(14,898)	3,274,005	9,933	(14,898)	3,259,107	9,888
Total General Plant			1,352,525,526	3,941,482	(1,581,934)	1,350,943,593	3,938,855.96	1,351,621	1,352,295,213	3,937,439.13	6,204,698	1,358,499,912	3,951,174.28	28,019,175	1,386,519,087	4,023,232.92
Mining Plant:																
Coal Mine	SE	0.000%	1,822,901	-	-	1,822,901	-	-	1,822,901	-	-	1,822,901	-	-	1,822,901	-
Total Mining Plant			1,822,901	-	-	1,822,901	-	-	1,822,901	-	-	1,822,901	-	-	1,822,901	-
Total Depreciation Expense			29,917,131,303	88,685,105	57,082,378	29,974,213,681	88,758,596	17,328,192	29,991,541,874	88,851,274	79,567,971	30,071,109,845	88,960,036	157,088,442	30,228,198,287	89,275,674

PacifiCorp
Oregon General Rate Case - December 2023
Jun 2021 - Dec 2022 Depreciation & Amortization Expense

Description	Factor	2018 Rate	Adjusted EPIS Balance Jun 2021	Depreciation Expense Jun 2021	Adjustments	Adjusted EPIS Balance Jul 2021	Depreciation Expense Jul 2021	Adjustments	Adjusted EPIS Balance Aug 2021	Depreciation Expense Aug 2021	Adjustments	Adjusted EPIS Balance Sep 2021	Depreciation Expense Sep 2021	Adjustments	Adjusted EPIS Balance Oct 2021	Depreciation Expense Oct 2021
AMORTIZATION EXPENSE																
Intangible Plant:																
California	CA	0.367%	481,167	147	-	481,167	147	-	481,167	147	-	481,167	147	-	481,167	147
Customer Service	CN	6.456%	214,248,773	1,152,666	(34,194)	214,214,579	1,152,574	(34,194)	214,180,385	1,152,390	(34,194)	214,146,192	1,152,206	(34,194)	214,111,998	1,152,022
Pre-merger Utah	SG	2.611%	477,596	1,039	-	477,596	1,039	-	477,596	1,039	-	477,596	1,039	-	477,596	1,039
Pre-merger Pacific	SG	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Idaho	ID	0.527%	4,371,145	1,920	(86)	4,371,059	1,920	(86)	4,370,973	1,920	(86)	4,370,886	1,920	(86)	4,370,800	1,920
Oregon	OR	0.254%	4,616,002	975	(363)	4,615,639	975	(363)	4,615,275	975	(363)	4,614,912	975	(363)	4,614,549	975
Fuel Related	SE	20.000%	9,106	152	(4,079)	5,026	118	(4,079)	947	50	(4,079)	(3,132)	(18)	(4,079)	(7,212)	(86)
Post-merger	SG	3.402%	210,683,247	597,312	(62,928)	210,620,319	597,223	(62,928)	210,557,391	597,044	(62,928)	210,494,464	596,866	(62,928)	210,431,536	596,688
Hydro Relicensing	SG-P	2.593%	103,455,075	223,537	(4,666)	103,450,409	223,532	(4,666)	103,445,744	223,522	(4,666)	103,441,078	223,512	(4,666)	103,436,412	223,502
Hydro Relicensing	SG-U	3.225%	10,014,897	26,917	(14,920)	9,999,977	26,897	(14,920)	9,985,056	26,857	(14,920)	9,970,136	26,817	(14,920)	9,955,215	26,777
General Office	SO	6.156%	432,009,413	2,216,030	1,427,051	433,436,464	2,219,690	(1,972,925)	431,463,539	2,218,290	2,021,630	433,485,169	2,218,415	289,608	433,774,777	2,224,343
Utah	UT	-0.148%	(26,162,598)	3,232	(561)	(26,163,160)	3,232	(561)	(26,163,721)	3,232	(561)	(26,164,283)	3,232	(561)	(26,164,844)	3,233
Washington	WA	0.155%	2,036,986	262	-	2,036,986	262	-	2,036,986	262	-	2,036,986	262	-	2,036,986	262
Eastern Wyoming	WYP	1.960%	5,668,980	9,261	(7,729)	5,661,251	9,254	(7,729)	5,653,523	9,242	(7,729)	5,645,794	9,229	(7,729)	5,638,066	9,217
Western Wyoming	WYU	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Klamath		0.000%	74,111,750	-	-	74,111,750	-	-	74,111,750	-	-	74,111,750	-	-	74,111,750	-
Total Intangible Plant			1,036,021,539	4,233,451	1,297,524	1,037,319,063	4,236,865	(2,102,451)	1,035,216,612	4,234,971	1,892,103	1,037,108,715	4,234,603	160,082	1,037,268,798	4,240,038
Hydro Production Plant:																
Pre-merger Pacific	SG	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG-P	2.126%	14,658,989	25,975	-	14,658,989	25,975	-	14,658,989	25,975	-	14,658,989	25,975	-	14,658,989	25,975
Post-merger	SG-U	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Hydro Plant			14,658,989	25,975	-	14,658,989	25,975	-	14,658,989	25,975	-	14,658,989	25,975	-	14,658,989	25,975
Other Production Plant:																
Post-merger	SG	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Other Plant			-	-	-	-	-	-	-	-	-	-	-	-	-	-
General Plant:																
California	CA	0.000%	505,860	-	-	505,860	-	-	505,860	-	-	505,860	-	-	505,860	-
General Office	CN	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Oregon	OR	5.852%	5,517,847	26,909	-	5,517,847	26,909	-	5,517,847	26,909	-	5,517,847	26,909	-	5,517,847	26,909
General Office	SO	5.965%	1,815,339	9,024	-	1,815,339	9,024	-	1,815,339	9,024	-	1,815,339	9,024	-	1,815,339	9,024
Utah	UT	0.000%	33,127	-	-	33,127	-	-	33,127	-	-	33,127	-	-	33,127	-
Washington	WA	3.801%	2,532,816	8,022	-	2,532,816	8,022	-	2,532,816	8,022	-	2,532,816	8,022	-	2,532,816	8,022
Eastern Wyoming	WYP	1.161%	4,580,607	4,431	-	4,580,607	4,431	-	4,580,607	4,431	-	4,580,607	4,431	-	4,580,607	4,431
Western Wyoming	WYU	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total General Plant			14,985,595	48,386	-	14,985,595	48,386.18	-	14,985,595	48,386.18	-	14,985,595	48,386.18	-	14,985,595	48,386.18
Total Amortization			1,065,666,123	4,307,812	1,297,524	1,066,963,647	4,311,225	(2,102,451)	1,064,861,196	4,309,332	1,892,103	1,066,753,300	4,308,964	160,082	1,066,913,382	4,314,398
Total Depreciation & Amortization			30,982,797,426	92,992,916	58,379,902	31,041,177,329	93,069,821	15,225,741	31,056,403,070	93,160,607	81,460,075	31,137,863,145	93,269,000	157,248,524	31,295,111,669	93,590,072

PacifiCorp
Oregon General Rate Case - December 2023
Jun 2021 - Dec 2022 Depreciation & Amortization Expense

Description	Factor	2018 Rate	Adjustments	Adjusted EPIS Balance Nov 2021	Depreciation Expense Nov 2021	Adjustments	Adjusted EPIS Balance Dec 2021	Depreciation Expense Dec 2021	Adjustments	Adjusted EPIS Balance Jan 2022	Depreciation Expense Jan 2022	Adjustments	Adjusted EPIS Balance Feb 2022	Depreciation Expense Feb 2022	Adjustments	Adjusted EPIS Balance Mar 2022
DEPRECIATION EXPENSE																
Steam Production Plant:																
Pre-merger Pacific	SG	6.692%	(411,968)	1,010,431,598	5,636,106	(411,968)	1,010,019,630	5,633,809	(411,968)	1,009,607,662	5,631,511	(411,968)	1,009,195,694	5,629,214	(411,968)	1,008,783,726
Pre-merger Utah	SG	5.015%	(538,554)	1,056,481,746	4,416,395	(538,554)	1,055,943,192	4,414,145	(538,554)	1,055,404,638	4,411,894	(538,554)	1,054,866,084	4,409,643	(538,554)	1,054,327,529
Post-merger	SG	6.992%	(342,184)	4,787,236,252	27,895,131	8,121,334	4,795,357,586	27,917,795	(3,677,827)	4,791,679,759	27,930,740	(3,402,284)	4,788,277,475	27,910,113	(3,017,763)	4,785,259,712
Geothermal - Blundell	SG	6.992%	-	29,402,029	171,319	-	29,402,029	171,319	-	29,402,029	171,319	-	29,402,029	171,319	-	29,402,029
Carbon	SG															
Pollution Control Equipment	SG	6.992%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pollution Control Equipment	SG	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG	0.000%	-	1,266,851	-	-	1,266,851	-	-	1,266,851	-	-	1,266,851	-	-	1,266,851
Total Steam Plant			(1,292,706)	6,884,818,477	38,118,951.33	7,170,812	6,891,989,289	38,137,066.81	(4,628,349)	6,887,360,939	38,145,464.26	(4,352,807)	6,883,008,133	38,120,288.97	(3,968,286)	6,879,039,847
Hydro Production Plant:																
Pre-merger Pacific	SG	2.210%	(50,121)	183,572,622	338,171	(50,121)	183,522,501	338,078	(50,121)	183,472,380	337,986	(50,121)	183,422,260	337,894	(50,121)	183,372,139
Pre-merger Utah	SG	3.181%	(32,867)	39,700,792	105,295	(32,867)	39,667,926	105,208	(32,867)	39,635,059	105,121	(32,867)	39,602,192	105,034	(32,867)	39,569,325
Post-merger	SG-P	2.741%	3,657,993	641,173,043	1,460,117	13,361,713	654,534,755	1,479,551	(134,488)	654,400,268	1,494,655	2,669,311	657,069,578	1,497,550	1,196,416	658,265,994
Post-merger	SG-U	4.692%	1,352,365	155,036,166	603,553	6,961,581	161,997,747	619,807	(101,594)	161,896,153	633,218	(101,594)	161,794,558	632,821	(101,594)	161,692,964
Klamath - New Capital	SG-P	20.000%	1,112,940	4,171,133	60,244	-	4,171,133	69,519	-	4,171,133	69,519	-	4,171,133	69,519	-	4,171,133
Klamath		0.000%	-	91,504,591	-	-	91,504,591	-	-	91,504,591	-	-	91,504,591	-	-	91,504,591
Total Hydro Plant			6,040,310	1,115,158,347	2,567,380	20,240,306	1,135,398,653	2,612,163	(319,070)	1,135,079,583	2,640,499	2,484,729	1,137,564,312	2,642,817	1,011,834	1,138,576,146
Other Production Plant:																
Pre-merger Utah	SG	0.000%	-	235,129	-	-	235,129	-	-	235,129	-	-	235,129	-	-	235,129
Post-merger	SG	3.503%	(1,732,913)	1,944,583,646	5,679,030	(1,571,078)	1,943,012,568	5,674,208	(2,062,920)	1,940,949,647	5,668,903	(2,062,920)	1,938,886,727	5,662,882	(2,062,920)	1,936,823,807
Post-merger Wind	SG-W	4.223%	3,211,844	3,230,874,661	11,364,241	3,413,055	3,234,287,716	11,375,898	1,002,446	3,235,290,162	11,383,667	1,002,446	3,236,292,608	11,387,195	1,002,446	3,237,295,054
Black Cap Solar	OR	0.000%	-	74,986	-	255,090	330,076	-	5,019	335,095	-	5,019	340,114	-	5,019	345,132
Post-merger	SG	4.825%	(39,401)	90,048,121	362,160	(39,401)	90,008,720	362,001	(42,147)	89,966,573	361,837	(42,147)	89,924,426	361,668	(42,147)	89,882,279
Total Other Plant			1,439,531	5,265,816,543	17,405,430.60	2,057,666	5,267,874,210	17,412,106.74	(1,097,602)	5,266,776,607	17,414,408.10	(1,097,602)	5,265,679,005	17,411,744.44	(1,097,602)	5,264,581,402
Transmission Plant:																
Pre-merger Pacific	SG	1.700%	(168,182)	478,960,604	678,609	(168,182)	478,792,422	678,370	(168,182)	478,624,239	678,132	(168,182)	478,456,057	677,894	(168,182)	478,287,875
Pre-merger Utah	SG	1.673%	(295,470)	619,196,246	863,441	(295,470)	618,900,776	863,029	(295,470)	618,605,307	862,617	(295,470)	618,309,837	862,205	(295,470)	618,014,367
Post-merger	SG	1.724%	40,742,304	6,653,317,852	9,527,677	38,166,406	6,691,484,258	9,584,349	2,920,669	6,694,404,927	9,613,859	4,228,954	6,698,633,881	9,618,993	8,115,236	6,706,749,117
Total Transmission Plant			40,278,653	7,751,474,702	11,069,725.74	37,702,754	7,789,177,457	11,125,748.47	2,457,017	7,791,634,473	11,154,607.39	3,765,302	7,795,399,775	11,159,092.14	7,651,585	7,803,051,360
Distribution Plant:																
California	CA	2.704%	11,314,127	305,092,094	674,803	1,056,089	306,148,183	688,742	881,709	307,029,892	690,925	1,192,832	308,222,724	693,263	3,787,545	312,010,268
Oregon	OR	2.271%	2,922,650	2,353,961,626	4,452,813	8,652,724	2,362,614,351	4,463,768	1,588,700	2,364,203,051	4,473,461	1,935,012	2,366,138,063	4,476,796	13,574,785	2,379,712,848
Washington	WA	2.588%	747,410	577,589,471	1,245,034	1,185,894	578,775,365	1,247,119	762,453	579,537,818	1,249,221	826,112	580,363,930	1,250,934	2,180,310	582,544,240
Eastern Wyoming	WYP	2.685%	1,934,474	681,722,828	1,523,372	13,254,205	694,977,033	1,540,366	1,273,313	696,250,347	1,556,621	1,252,858	697,503,205	1,559,447	1,494,568	698,997,773
Utah	UT	2.540%	10,585,271	3,417,757,971	7,224,185	22,399,037	3,440,157,008	7,259,099	11,050,843	3,451,207,851	7,294,505	14,412,404	3,465,620,255	7,321,458	22,599,508	3,488,219,763
Idaho	ID	2.561%	7,330,647	412,824,762	873,257	2,668,476	415,493,238	883,927	2,436,609	417,929,847	889,375	1,789,296	419,719,143	893,885	2,700,291	422,419,434
Western Wyoming	WYU	2.682%	(27,785)	154,912,060	346,215	(27,785)	154,884,276	346,153	(27,785)	154,856,491	346,091	(27,785)	154,828,706	346,029	(27,785)	154,800,922
Total Distribution Plant			34,806,794	7,903,860,813	16,339,679.37	49,188,641	7,953,049,454	16,429,174.58	17,965,843	7,971,015,296	16,500,198.82	21,380,730	7,992,396,027	16,541,811.32	46,309,222	8,038,705,249
General Plant:																
California	CA	2.021%	(32,129)	22,514,959	37,948	(36,884)	22,478,074	37,890	27,940	22,506,014	37,882	(17,041)	22,488,973	37,891	30,143	22,519,116
Oregon	OR	2.577%	811,710	221,467,584	474,717	7,175,233	228,642,817	483,293	229,532	228,872,349	491,244	(107,779)	228,764,570	491,375	255,379	229,019,949
Washington	WA	2.371%	31,569	46,408,369	91,677	70,377	46,478,746	91,778	(6,346)	46,472,400	91,841	(73,979)	46,398,421	91,762	(2,951)	46,395,470
Eastern Wyoming	WYP	2.539%	244,039	81,737,127	172,678	2,766,378	84,503,505	175,863	294,575	84,798,080	179,101	(24,893)	84,773,187	179,386	16,913	84,790,101
Utah	UT	2.215%	2,427,625	245,644,418	451,148	7,021,627	252,666,045	459,868	2,060,197	254,726,242	468,250	1,222,335	255,948,576	471,279	1,517,713	257,466,290
Idaho	ID	1.990%	208,581	51,921,662	85,922	1,135,561	53,057,223	87,037	149,285	53,206,508	88,102	42,967	53,249,475	88,261	57,433	53,306,909
Western Wyoming	WYU	2.182%	(31,708)	18,042,420	32,836	(31,708)	18,010,713	32,779	(31,708)	17,979,005	32,721	(31,708)	17,947,298	32,663	(31,708)	17,915,590
Pre-merger Pacific	SG	2.093%	(13,917)	937,729	1,648	(13,917)	923,811	1,624	(13,917)	909,894	1,599	(13,917)	895,977	1,575	(13,917)	882,060
Pre-merger Utah	SG	1.231%	(30,778)	2,668,104	2,753	(30,778)	2,637,326	2,721	(30,778)	2,606,547	2,689	(30,778)	2,575,769	2,658	(30,778)	2,544,990
Post-merger	SG	3.438%	378,735	301,771,852	863,927	4,951,199	306,723,051	871,561	(351,727)	306,371,325	878,149	(315,869)	306,055,456	877,193	(272,803)	305,782,654
General Office	SO	5.656%	5,875,563	382,893,939	1,790,956	7,050,289	389,944,228	1,821,419	(52,829)	389,891,399	1,837,911	(72,673)	389,818,727	1,837,615	(575,569)	389,243,158
General Office	SG	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
General Office	SG	3.982%	-	223,232	741	-	223,232	741	-	223,232	741	-	223,232	741	-	223,232
Customer Service	CN	5.953%	(99,428)	16,798,447	83,582	(99,428)	16,699,018	83,089	(99,428)	16,599,590	82,596	(99,428)	16,500,161	82,102	(99,428)	16,400,733
Fuel Related	SE	3.632%	(14,898)	3,244,210	9,843	(14,898)	3,229,312	9,798	(14,898)	3,214,414	9,753	(14,898)	3,199,517	9,708	(14,898)	3,184,619
Total General Plant			9,754,964	1,396,274,051	4,100,376.49	29,943,051	1,426,217,102	4,159,460.10	2,159,897	1,428,376,999	4,202,578.71	462,340	1,428,839,339	4,204,209.39	835,531	1,429,674,871
Mining Plant:																
Coal Mine	SE	0.000%	-	1,822,901	-	-	1,822,901	-	-	1,822,901	-	-	1,822,901	-	-	1,822,901
Total Mining Plant			-	1,822,901	-	-	1,822,901	-	-	1,822,901	-	-	1,822,901	-	-	1,822,901
Total Depreciation Expense			91,027,546	30,319,225,833	89,601,543	146,303,231	30,465,529,064	89,875,720	16,537,735	30,482,066,799	90,057,757	22,642,692	30,504,709,492	90,079,963	50,742,283	30,555,451,775

PacifiCorp
Oregon General Rate Case - December 2023
Jun 2021 - Dec 2022 Depreciation & Amortization Expense

Description	Factor	2018 Rate	Adjustments	Adjusted EPIS Balance Nov 2021	Depreciation Expense Nov 2021	Adjustments	Adjusted EPIS Balance Dec 2021	Depreciation Expense Dec 2021	Adjustments	Adjusted EPIS Balance Jan 2022	Depreciation Expense Jan 2022	Adjustments	Adjusted EPIS Balance Feb 2022	Depreciation Expense Feb 2022	Adjustments	Adjusted EPIS Balance Mar 2022
AMORTIZATION EXPENSE																
Intangible Plant:																
California	CA	0.367%	-	481,167	147	-	481,167	147	-	481,167	147	-	481,167	147	-	481,167
Customer Service	CN	6.456%	(34,194)	214,077,804	1,151,838	(34,194)	214,043,611	1,151,654	(34,194)	214,009,417	1,151,470	(34,194)	213,975,223	1,151,286	(34,194)	213,941,030
Pre-merger Utah	SG	2.611%	-	477,596	1,039	-	477,596	1,039	-	477,596	1,039	-	477,596	1,039	-	477,596
Pre-merger Pacific	SG	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Idaho	ID	0.527%	(86)	4,370,714	1,920	(86)	4,370,628	1,920	(86)	4,370,541	1,920	(86)	4,370,455	1,920	(86)	4,370,369
Oregon	OR	0.254%	(363)	4,614,186	975	(363)	4,613,822	975	(363)	4,613,459	975	(363)	4,613,096	975	(363)	4,612,732
Fuel Related	SE	20.000%	(4,079)	(11,291)	(154)	(4,079)	(15,371)	(222)	(4,079)	(19,450)	(290)	(4,079)	(23,529)	(358)	(4,079)	(27,609)
Post-merger	SG	3.402%	(62,928)	210,368,609	596,509	(62,928)	210,305,681	596,331	(62,928)	210,242,753	596,152	(62,928)	210,179,826	595,974	(62,928)	210,116,898
Hydro Relicensing	SG-P	2.593%	(4,666)	103,431,747	223,492	(4,666)	103,427,081	223,482	(4,666)	103,422,416	223,472	(4,666)	103,417,750	223,461	(4,666)	103,413,085
Hydro Relicensing	SG-U	3.225%	(14,920)	9,940,295	26,737	(14,920)	9,925,374	26,697	(14,920)	9,910,454	26,657	(14,920)	9,895,534	26,617	(14,920)	9,880,613
General Office	SO	6.156%	7,685,914	441,460,691	2,244,799	5,117,782	446,578,473	2,277,638	3,078,781	449,657,253	2,298,660	(596,409)	449,060,844	2,305,027	223,691	449,284,535
Utah	UT	-0.148%	(561)	(26,165,405)	3,233	(561)	(26,165,967)	3,233	(561)	(26,166,528)	3,233	(561)	(26,167,090)	3,233	(561)	(26,167,651)
Washington	WA	0.155%	-	2,036,986	262	-	2,036,986	262	-	2,036,986	262	-	2,036,986	262	-	2,036,986
Eastern Wyoming	WYP	1.960%	(7,729)	5,630,337	9,204	(7,729)	5,622,608	9,191	(7,729)	5,614,880	9,179	(7,729)	5,607,151	9,166	(7,729)	5,599,423
Western Wyoming	WYU	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Klamath		0.000%	-	74,111,750	-	-	74,111,750	-	-	74,111,750		-	74,111,750		-	74,111,750
Total Intangible Plant			7,556,388	1,044,825,185	4,260,000	4,988,256	1,049,813,441	4,292,346	2,949,254	1,052,762,695	4,312,875	(725,936)	1,052,036,760	4,318,748	94,164	1,052,130,924
Hydro Production Plant:																
Pre-merger Pacific	SG	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG-P	2.126%	-	14,658,989	25,975	-	14,658,989	25,975	-	14,658,989	25,975	-	14,658,989	25,975	-	14,658,989
Post-merger	SG-U	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Hydro Plant			-	14,658,989	25,975	-	14,658,989	25,975	-	14,658,989	25,975	-	14,658,989	25,975	-	14,658,989
Other Production Plant:																
Post-merger	SG	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Other Plant			-	-	-	-	-	-	-	-	-	-	-	-	-	-
General Plant:																
California	CA	0.000%	-	505,860	-	-	505,860	-	-	505,860	-	-	505,860	-	-	505,860
General Office	CN	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Oregon	OR	5.852%	-	5,517,847	26,909	-	5,517,847	26,909	-	5,517,847	26,909	-	5,517,847	26,909	-	5,517,847
General Office	SO	5.965%	-	1,815,339	9,024	-	1,815,339	9,024	-	1,815,339	9,024	-	1,815,339	9,024	-	1,815,339
Utah	UT	0.000%	-	33,127	-	-	33,127	-	-	33,127	-	-	33,127	-	-	33,127
Washington	WA	3.801%	-	2,532,816	8,022	-	2,532,816	8,022	-	2,532,816	8,022	-	2,532,816	8,022	-	2,532,816
Eastern Wyoming	WYP	1.161%	-	4,580,607	4,431	-	4,580,607	4,431	-	4,580,607	4,431	-	4,580,607	4,431	-	4,580,607
Western Wyoming	WYU	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total General Plant			-	14,985,595	48,386.18	-	14,985,595	48,386.18	-	14,985,595	48,386.18	-	14,985,595	48,386.18	-	14,985,595
Total Amortization			7,556,388	1,074,469,769	4,334,361	4,988,256	1,079,458,025	4,366,706	2,949,254	1,082,407,279	4,387,236	(725,936)	1,081,681,344	4,393,109	94,164	1,081,775,508
Total Depreciation & Amortization			98,583,934	31,393,695,603	93,935,904	151,291,487	31,544,987,089	94,242,427	19,486,990	31,564,474,079	94,444,992	21,916,756	31,586,390,835	94,473,073	50,836,448	31,637,227,283

PacifiCorp
Oregon General Rate Case - December 2023
Jun 2021 - Dec 2022 Depreciation & Amortization Expense

Description	Factor	2018 Rate	Depreciation Expense Mar 2022	Adjustments	Adjusted EPIS Balance Apr 2022	Depreciation Expense Apr 2022	Adjustments	Adjusted EPIS Balance May 2022	Depreciation Expense May 2022	Adjustments	Adjusted EPIS Balance Jun 2022	Depreciation Expense Jun 2022	Adjustments	Adjusted EPIS Balance Jul 2022	Depreciation Expense Jul 2022	Adjustments
DEPRECIATION EXPENSE																
Steam Production Plant:																
Pre-merger Pacific	SG	6.692%	5,626,916	(411,968)	1,008,371,757	5,624,619	(411,968)	1,007,959,789	5,622,321	(411,968)	1,007,547,821	5,620,024	(411,968)	1,007,135,853	5,617,726	(411,968)
Pre-merger Utah	SG	5.015%	4,407,392	(538,554)	1,053,788,975	4,405,142	(538,554)	1,053,250,421	4,402,891	(538,554)	1,052,711,867	4,400,640	(538,554)	1,052,173,312	4,398,390	(538,554)
Post-merger	SG	6.992%	27,891,409	20,453,230	4,805,712,942	27,942,205	33,139,910	4,838,852,852	28,098,343	11,264,526	4,850,117,378	28,227,710	2,791,402	4,852,908,780	28,268,660	(3,421,544)
Geothermal - Blundell	SG	6.992%	171,319	-	29,402,029	171,319	-	29,402,029	171,319	-	29,402,029	171,319	-	29,402,029	171,319	-
Carbon	SG															
Pollution Control Equipment	SG	6.992%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pollution Control Equipment	SG	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG	0.000%	-	-	1,266,851	-	-	1,266,851	-	-	1,266,851	-	-	1,266,851	-	-
Total Steam Plant			38,097,036.70	19,502,708	6,898,542,555	38,143,284.76	32,189,388	6,930,731,943	38,294,874.07	10,314,004	6,941,045,946	38,419,693.13	1,840,880	6,942,886,826	38,456,095.28	(4,372,067)
Hydro Production Plant:																
Pre-merger Pacific	SG	2.210%	337,801	(50,121)	183,322,018	337,709	(50,121)	183,271,897	337,617	(50,121)	183,221,776	337,525	(50,121)	183,171,656	337,432	(50,121)
Pre-merger Utah	SG	3.181%	104,947	(32,867)	39,536,458	104,860	(32,867)	39,503,591	104,773	(32,867)	39,470,725	104,685	(32,867)	39,437,858	104,598	(32,867)
Post-merger	SG-P	2.741%	1,501,964	185,405	658,451,399	1,503,542	598,587	659,049,986	1,504,437	11,713,429	670,763,416	1,518,496	198,929	670,962,344	1,532,099	7,040,461
Post-merger	SG-U	4.692%	632,424	(101,594)	161,591,370	632,026	(101,594)	161,489,775	631,629	(32,229)	161,457,546	631,367	1,125,735	162,583,282	633,505	(101,594)
Klamath - New Capital	SG-P	20.000%	69,519	-	4,171,133	69,519	-	4,171,133	69,519	-	4,171,133	69,519	-	4,171,133	69,519	-
Klamath		0.000%	-	-	91,504,591	-	-	91,504,591	-	-	91,504,591	-	-	91,504,591	-	-
Total Hydro Plant			2,646,655	823	1,138,576,969	2,647,656	414,005	1,138,990,974	2,647,974	11,598,213	1,150,589,187	2,661,592	1,241,676	1,151,830,863	2,677,153	6,855,879
Other Production Plant:																
Pre-merger Utah	SG	0.000%	-	-	235,129	-	-	235,129	-	-	235,129	-	-	235,129	-	-
Post-merger	SG	3.503%	5,656,860	21,353,942	1,958,177,749	5,685,016	1,498,455	1,959,676,204	5,718,371	(1,126,057)	1,958,550,147	5,718,914	(1,817,864)	1,956,732,283	5,714,617	(2,057,700)
Post-merger Wind	SG-W	4.223%	11,390,723	1,002,446	3,238,297,500	11,394,251	1,057,446	3,239,354,946	11,397,875	1,002,446	3,240,357,392	11,401,500	1,002,446	3,241,359,838	11,405,027	1,002,446
Black Cap Solar	OR	0.000%	-	5,019	350,151	-	5,019	355,170	-	5,019	360,189	-	5,019	365,207	-	5,019
Post-merger	SG	4.825%	361,498	(42,147)	89,840,132	361,329	(42,147)	89,797,985	361,159	(19,753)	89,778,232	361,035	(42,147)	89,736,085	360,911	(42,147)
Total Other Plant			17,409,080.77	22,319,260	5,286,900,662	17,440,595.58	2,518,773	5,289,419,434	17,477,405.24	(138,346)	5,289,281,089	17,481,448.85	(852,546)	5,288,428,542	17,480,555.30	(1,092,382)
Transmission Plant:																
Pre-merger Pacific	SG	1.700%	677,656	(168,182)	478,119,693	677,417	(168,182)	477,951,511	677,179	(168,182)	477,783,329	676,941	(168,182)	477,615,146	676,703	(168,182)
Pre-merger Utah	SG	1.673%	861,793	(295,470)	617,718,898	861,381	(295,470)	617,423,428	860,969	(295,470)	617,127,958	860,557	(295,470)	616,832,489	860,145	(295,470)
Post-merger	SG	1.724%	9,627,859	10,922,632	6,717,671,749	9,641,532	28,377,815	6,746,049,564	9,669,758	18,631,954	6,764,681,518	9,703,521	38,591,372	6,803,272,890	9,744,619	15,815,183
Total Transmission Plant			11,167,307.68	10,458,980	7,813,510,340	11,180,330.67	27,914,163	7,841,424,503	11,207,906.42	18,168,302	7,859,592,805	11,241,019.07	38,127,720	7,897,720,525	11,281,467.18	15,351,532
Distribution Plant:																
California	CA	2.704%	698,875	1,032,357	313,042,626	704,306	5,565,135	318,607,761	711,740	6,749,241	325,357,002	725,616	4,952,388	330,309,390	738,801	737,552
Oregon	OR	2.271%	4,491,474	5,440,658	2,385,153,507	4,509,470	27,394,986	2,412,548,493	4,540,546	18,831,691	2,431,380,183	4,584,295	10,538,021	2,441,918,204	4,612,090	5,828,050
Washington	WA	2.588%	1,254,176	1,843,889	584,388,128	1,258,516	2,894,407	587,282,535	1,263,627	2,745,527	590,028,062	1,269,709	19,674,340	609,702,402	1,293,889	1,638,668
Eastern Wyoming	WYP	2.685%	1,562,521	1,637,015	700,634,788	1,566,025	2,337,306	702,972,094	1,570,472	1,925,179	704,897,274	1,575,241	1,804,819	706,702,093	1,579,415	2,094,681
Utah	UT	2.540%	7,360,635	15,699,539	3,503,919,302	7,401,175	34,281,300	3,538,200,602	7,454,080	19,592,362	3,557,792,964	7,511,105	16,819,169	3,574,612,134	7,549,646	15,227,001
Idaho	ID	2.561%	898,676	2,077,140	424,496,574	903,774	3,053,427	427,550,001	909,249	1,999,241	429,549,241	914,641	2,019,668	431,568,909	918,929	2,027,729
Western Wyoming	WYU	2.682%	345,967	(27,785)	154,773,137	345,904	(27,785)	154,745,352	345,842	(27,785)	154,717,568	345,780	(27,785)	154,689,783	345,718	(27,785)
Total Distribution Plant			16,612,324.07	27,702,812	8,066,408,061	16,689,170.82	75,498,777	8,141,906,838	16,795,555.07	51,815,456	8,193,722,295	16,926,386.59	55,780,620	8,249,502,914	17,038,488.50	27,525,896
General Plant:																
California	CA	2.021%	37,902	(26,597)	22,492,519	37,905	(6,915)	22,485,604	37,877	37,130	22,522,734	37,902	74,104	22,596,839	37,996	322,168
Oregon	OR	2.577%	491,533	461,547	229,481,496	492,303	652,889	230,134,386	493,499	1,144,411	231,278,797	495,429	775,644	232,054,441	497,491	440,656
Washington	WA	2.371%	91,686	(18,788)	46,376,682	91,665	13,859	46,390,541	91,660	100,356	46,490,897	91,773	70,969	46,561,866	91,942	(14,324)
Eastern Wyoming	WYP	2.539%	179,378	190,157	84,980,258	179,597	309,960	85,290,217	180,126	471,432	85,761,650	180,953	95,098	85,856,747	181,552	504,003
Utah	UT	2.215%	473,808	1,763,441	259,229,731	476,836	2,574,412	261,804,142	480,839	2,972,976	264,777,119	485,958	2,319,195	267,096,313	490,842	1,317,607
Idaho	ID	1.990%	88,344	56,532	53,363,441	88,439	96,578	53,460,019	88,566	150,958	53,610,977	88,771	83,534	53,694,511	88,965	150,189
Western Wyoming	WYU	2.182%	32,606	(31,708)	17,883,883	32,548	(31,708)	17,852,175	32,490	(31,708)	17,820,467	32,433	(31,708)	17,788,760	32,375	(31,708)
Pre-merger Pacific	SG	2.093%	1,551	(13,917)	868,143	1,526	(13,917)	854,225	1,502	(13,917)	840,308	1,478	(13,917)	826,391	1,454	(13,917)
Pre-merger Utah	SG	1.231%	2,626	(30,778)	2,514,212	2,595	(30,778)	2,483,433	2,563	(30,778)	2,452,655	2,532	(30,778)	2,421,877	2,500	(30,778)
Post-merger	SG	3.438%	876,350	(228,856)	305,553,798	875,631	(272,771)	305,281,027	874,913	(272,457)	305,008,570	874,132	(271,142)	304,737,429	873,353	(280,017)
General Office	SO	5.656%	1,836,087	93,518	389,336,676	1,834,951	1,131,631	390,468,308	1,837,839	3,035,787	393,504,095	1,847,660	363,699	393,867,794	1,855,672	(171,889)
General Office	SG	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
General Office	SG	3.982%	741	-	223,232	741	-	223,232	741	-	223,232	741	-	223,232	741	-
Customer Service	CN	5.953%	81,609	(99,428)	16,301,304	81,116	(99,428)	16,201,876	80,623	(99,428)	16,102,447	80,129	(99,428)	16,003,019	79,636	(99,428)
Fuel Related	SE	3.632%	9,663	(14,898)	3,169,722	9,617	(14,898)	3,154,824	9,572	(14,898)	3,139,927	9,527	(14,898)	3,125,029	9,482	(14,898)
Total General Plant			4,203,883.57	2,100,225	1,431,775,096	4,205,469.95	4,308,915	1,436,084,011	4,212,809.75	7,449,864	1,443,533,876	4,229,418.07	3,320,371	1,446,854,247	4,244,001.69	2,077,665
Mining Plant:																
Coal Mine	SE	0.000%	-	-	1,822,901	-	-	1,822,901	-	-	1,822,901	-	-	1,822,901	-	-
Total Mining Plant			-	-	1,822,901	-	-	1,822,901	-	-	1,822,901	-	-	1,822,901	-	-
Total Depreciation Expense			90,136,287	82,084,809	30,637,536,583	90,306,508	142,844,021	30,780,380,605	90,636,525	99,207,493	30,879,588,098	90,959,558	99,458,721	30,979,046,819	91,177,761	46,346,523

PacifiCorp
Oregon General Rate Case - December 2023
Jun 2021 - Dec 2022 Depreciation & Amortization Expense

Description	Factor	2018 Rate	Depreciation Expense Mar 2022	Adjustments	Adjusted EPIS Balance Apr 2022	Depreciation Expense Apr 2022	Adjustments	Adjusted EPIS Balance May 2022	Depreciation Expense May 2022	Adjustments	Adjusted EPIS Balance Jun 2022	Depreciation Expense Jun 2022	Adjustments	Adjusted EPIS Balance Jul 2022	Depreciation Expense Jul 2022	Adjustments
AMORTIZATION EXPENSE																
Intangible Plant:																
California	CA	0.367%	147	-	481,167	147	-	481,167	147	-	481,167	147	-	481,167	147	-
Customer Service	CN	6.456%	1,151,102	(34,194)	213,906,836	1,150,918	(34,194)	213,872,642	1,150,734	(34,194)	213,838,449	1,150,550	(34,194)	213,804,255	1,150,366	(34,194)
Pre-merger Utah	SG	2.611%	1,039	-	477,596	1,039	-	477,596	1,039	-	477,596	1,039	-	477,596	1,039	-
Pre-merger Pacific	SG	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Idaho	ID	0.527%	1,920	(86)	4,370,283	1,920	(86)	4,370,196	1,920	(86)	4,370,110	1,920	(86)	4,370,024	1,920	(86)
Oregon	OR	0.254%	975	(363)	4,612,369	975	(363)	4,612,006	974	(363)	4,611,642	974	(363)	4,611,279	974	(363)
Fuel Related	SE	20.000%	(426)	(4,079)	(31,688)	(494)	(4,079)	(35,767)	(562)	(4,079)	(39,847)	(630)	(4,079)	(43,926)	(698)	(4,079)
Post-merger	SG	3.402%	595,796	(62,928)	210,053,970	595,617	(62,928)	209,991,043	595,439	(62,928)	209,928,115	595,260	(62,928)	209,865,187	595,082	(62,928)
Hydro Relicensing	SG-P	2.593%	223,451	(4,666)	103,408,419	223,441	(4,666)	103,403,753	223,431	(4,666)	103,399,088	223,421	(4,666)	103,394,422	223,411	(4,666)
Hydro Relicensing	SG-U	3.225%	26,577	(14,920)	9,865,693	26,536	(14,920)	9,850,772	26,496	(14,920)	9,835,852	26,456	(14,920)	9,820,931	26,416	(14,920)
General Office	SO	6.156%	2,304,071	435,497	449,720,031	2,305,762	(38,349)	449,681,682	2,306,780	12,605,754	462,287,436	2,339,013	(320,779)	461,966,656	2,370,521	(383,729)
Utah	UT	-0.148%	3,233	(561)	(26,168,212)	3,233	(561)	(26,168,774)	3,233	(561)	(26,169,335)	3,233	(561)	(26,169,897)	3,233	(561)
Washington	WA	0.155%	262	-	2,036,986	262	-	2,036,986	262	-	2,036,986	262	-	2,036,986	262	-
Eastern Wyoming	WYP	1.960%	9,153	(7,729)	5,591,694	9,141	(7,729)	5,583,966	9,128	(7,729)	5,576,237	9,116	(7,729)	5,568,509	9,103	(7,729)
Western Wyoming	WYU	0.000%	-	-		-	-		-	-		-	-		-	-
Klamath		0.000%		-	74,111,750		-	74,111,750		-	74,111,750		-	74,111,750		-
Total Intangible Plant			4,317,299	305,970	1,052,436,894	4,318,497	(167,876)	1,052,269,019	4,319,022	12,476,227	1,064,745,246	4,350,762	(450,306)	1,064,294,941	4,381,777	(513,256)
Hydro Production Plant:																
Pre-merger Pacific	SG	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG-P	2.126%	25,975	-	14,658,989	25,975	-	14,658,989	25,975	-	14,658,989	25,975	-	14,658,989	25,975	-
Post-merger	SG-U	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Hydro Plant			25,975	-	14,658,989	25,975	-	14,658,989	25,975	-	14,658,989	25,975	-	14,658,989	25,975	-
Other Production Plant:																
Post-merger	SG	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Other Plant			-	-	-	-	-	-	-	-	-	-	-	-	-	-
General Plant:																
California	CA	0.000%	-	-	505,860	-	-	505,860	-	-	505,860	-	-	505,860	-	-
General Office	CN	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Oregon	OR	5.852%	26,909	-	5,517,847	26,909	-	5,517,847	26,909	-	5,517,847	26,909	-	5,517,847	26,909	-
General Office	SO	5.965%	9,024	-	1,815,339	9,024	-	1,815,339	9,024	-	1,815,339	9,024	-	1,815,339	9,024	-
Utah	UT	0.000%	-	-	33,127	-	-	33,127	-	-	33,127	-	-	33,127	-	-
Washington	WA	3.801%	8,022	-	2,532,816	8,022	-	2,532,816	8,022	-	2,532,816	8,022	-	2,532,816	8,022	-
Eastern Wyoming	WYP	1.161%	4,431	-	4,580,607	4,431	-	4,580,607	4,431	-	4,580,607	4,431	-	4,580,607	4,431	-
Western Wyoming	WYU	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total General Plant			48,386.18	-	14,985,595	48,386.18	-	14,985,595	48,386.18	-	14,985,595	48,386.18	-	14,985,595	48,386.18	-
Total Amortization			4,391,660	305,970	1,082,081,479	4,392,858	(167,876)	1,081,913,603	4,393,383	12,476,227	1,094,389,831	4,425,123	(450,306)	1,093,939,525	4,456,138	(513,256)
Total Depreciation & Amortization			94,527,948	82,390,779	31,719,618,062	94,699,365	142,676,146	31,862,294,208	95,029,908	111,683,721	31,973,977,929	95,384,681	99,008,415	32,072,986,344	95,633,899	45,833,268

PacifiCorp
Oregon General Rate Case - December 2023
Jun 2021 - Dec 2022 Depreciation & Amortization Expense

Description	Factor	2018 Rate	Adjusted EPIS Balance Aug 2022	Depreciation Expense Aug 2022	Adjustments	Adjusted EPIS Balance Sep 2022	Depreciation Expense Sep 2022	Adjustments	Adjusted EPIS Balance Oct 2022	Depreciation Expense Oct 2022	Adjustments	Adjusted EPIS Balance Nov 2022	Depreciation Expense Nov 2022	Adjustments	Adjusted EPIS Balance Dec 2022	Depreciation Expense Dec 2022
DEPRECIATION EXPENSE																
Steam Production Plant:																
Pre-merger Pacific	SG	6.692%	1,006,723,885	5,615,429	(411,968)	1,006,311,917	5,613,132	(411,968)	1,005,899,948	5,610,834	(411,968)	1,005,487,980	5,608,537	(411,968)	1,005,076,012	5,606,239
Pre-merger Utah	SG	5.015%	1,051,634,758	4,396,139	(538,554)	1,051,096,204	4,393,888	(538,554)	1,050,557,650	4,391,637	(538,554)	1,050,019,095	4,389,387	(538,554)	1,049,480,541	4,387,136
Post-merger	SG	6.992%	4,849,487,236	28,266,825	(2,995,353)	4,846,491,883	28,248,130	989,081	4,847,480,964	28,242,285	4,671,246	4,852,152,210	28,258,775	12,849,455	4,865,001,665	28,309,820
Geothermal - Blundell	SG	6.992%	29,402,029	171,319	-	29,402,029	171,319	-	29,402,029	171,319	-	29,402,029	171,319	-	29,402,029	171,319
Carbon	SG															
Pollution Control Equipment	SG	6.992%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pollution Control Equipment	SG	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG	0.000%	1,266,851	-	-	1,266,851	-	-	1,266,851	-	-	1,266,851	-	-	1,266,851	-
Total Steam Plant			6,938,514,759	38,449,711.24	(3,945,876)	6,934,568,884	38,426,468.15	38,559	6,934,607,442	38,416,074.91	3,720,724	6,938,328,166	38,428,017.43	11,898,933	6,950,227,099	38,474,513.81
Hydro Production Plant:																
Pre-merger Pacific	SG	2.210%	183,121,535	337,340	(50,121)	183,071,414	337,248	(50,121)	183,021,293	337,155	(50,121)	182,971,172	337,063	(50,121)	182,921,052	336,971
Pre-merger Utah	SG	3.181%	39,404,991	104,511	(32,867)	39,372,124	104,424	(32,867)	39,339,257	104,337	(32,867)	39,306,390	104,250	(32,867)	39,273,524	104,163
Post-merger	SG-P	2.741%	678,002,805	1,540,365	187,933	678,190,738	1,548,619	1,411,337	679,602,075	1,550,445	5,114,339	684,716,415	1,557,897	27,729,937	712,446,352	1,595,401
Post-merger	SG-U	4.692%	162,481,687	635,507	(101,594)	162,380,093	635,110	3,396,591	165,776,684	641,552	(52,907)	165,723,777	648,089	17,562,814	183,286,592	682,321
Klamath - New Capital	SG-P	20.000%	4,171,133	69,519	-	4,171,133	69,519	-	4,171,133	69,519	3,493,814	7,664,947	98,634	1,982,716	9,647,664	144,272
Klamath		0.000%	91,504,591	-	-	91,504,591	-	-	91,504,591	-	-	91,504,591	-	-	91,504,591	-
Total Hydro Plant			1,158,686,742	2,687,242	3,351	1,158,690,093	2,694,920	4,724,941	1,163,415,034	2,703,008	8,472,259	1,171,887,293	2,745,932	47,192,480	1,219,079,773	2,863,127
Other Production Plant:																
Pre-merger Utah	SG	0.000%	235,129	-	-	235,129	-	-	235,129	-	-	235,129	-	-	235,129	-
Post-merger	SG	3.503%	1,954,674,583	5,708,961	(2,057,700)	1,952,616,883	5,702,954	757,437	1,953,374,320	5,701,056	(2,057,700)	1,951,316,621	5,699,158	4,809,958	1,956,126,579	5,703,176
Post-merger Wind	SG-W	4.223%	3,242,362,283	11,408,555	1,002,446	3,243,364,729	11,412,083	1,002,446	3,244,367,175	11,415,611	1,002,446	3,245,369,621	11,419,138	1,002,446	3,246,372,067	11,422,666
Black Cap Solar	OR	0.000%	370,226	-	5,019	375,245	-	5,019	380,264	-	5,019	385,282	-	5,019	390,301	-
Post-merger	SG	4.825%	89,693,938	360,741	(42,147)	89,651,791	360,572	(42,147)	89,609,644	360,402	(42,147)	89,567,497	360,233	20,439	89,587,935	360,189
Total Other Plant			5,287,336,160	17,478,256.93	(1,092,382)	5,286,243,778	17,475,608.50	1,722,755	5,287,966,533	17,477,068.95	(1,092,382)	5,286,874,150	17,478,529.40	5,837,862	5,292,712,012	17,486,030.61
Transmission Plant:																
Pre-merger Pacific	SG	1.700%	477,446,964	676,464	(168,182)	477,278,782	676,226	(168,182)	477,110,600	675,988	(168,182)	476,942,418	675,750	(168,182)	476,774,235	675,511
Pre-merger Utah	SG	1.673%	616,537,019	859,733	(295,470)	616,241,549	859,321	(295,470)	615,946,080	858,909	(295,470)	615,650,610	858,498	(295,470)	615,355,140	858,086
Post-merger	SG	1.724%	6,819,088,074	9,783,695	16,092,947	6,835,181,021	9,806,611	30,671,034	6,865,852,054	9,840,198	41,234,807	6,907,086,862	9,891,841	44,869,272	6,951,956,134	9,953,682
Total Transmission Plant			7,913,072,057	11,319,892.26	15,629,295	7,928,701,352	11,342,158.78	30,207,382	7,958,908,734	11,375,094.90	40,771,156	7,999,679,890	11,426,088.12	44,405,620	8,044,085,510	11,487,278.63
Distribution Plant:																
California	CA	2.704%	331,046,942	745,212	823,811	331,870,753	746,972	2,040,972	333,911,724	750,200	1,672,946	335,584,670	754,385	6,614,111	342,198,781	763,722
Oregon	OR	2.271%	2,447,746,254	4,627,579	10,039,794	2,457,786,048	4,642,597	5,759,640	2,463,545,688	4,657,549	4,365,110	2,467,910,797	4,667,131	16,417,329	2,484,328,127	4,686,800
Washington	WA	2.588%	611,341,070	1,316,874	1,044,016	612,385,087	1,319,767	1,287,687	613,672,774	1,322,282	1,124,687	614,797,460	1,324,884	4,613,975	619,411,435	1,331,073
Eastern Wyoming	WYP	2.685%	708,796,773	1,583,778	1,910,503	710,707,276	1,588,259	1,706,716	712,413,993	1,592,306	1,559,003	713,972,995	1,595,960	2,037,706	716,010,701	1,599,985
Utah	UT	2.540%	3,589,839,134	7,583,567	14,330,857	3,604,169,991	7,614,854	22,009,376	3,626,179,367	7,653,320	25,375,579	3,651,554,946	7,703,477	19,772,073	3,671,327,019	7,751,266
Idaho	ID	2.561%	433,596,638	923,248	2,751,098	436,347,737	928,348	2,072,825	438,420,561	933,496	1,799,694	440,220,256	937,628	4,123,486	444,343,741	943,949
Western Wyoming	WYU	2.682%	154,661,999	345,656	(27,785)	154,634,214	345,594	(27,785)	154,606,429	345,532	(27,785)	154,578,645	345,470	(27,785)	154,550,860	345,408
Total Distribution Plant			8,277,028,811	17,125,915.42	30,872,295	8,307,901,106	17,186,391.18	34,849,430	8,342,750,536	17,254,685.53	35,869,233	8,378,619,770	17,328,935.43	53,550,895	8,432,170,664	17,422,202.59
General Plant:																
California	CA	2.021%	22,919,007	38,330	93,132	23,012,139	38,680	65,976	23,078,115	38,813	46,603	23,124,718	38,908	329,809	23,454,527	39,225
Oregon	OR	2.577%	232,495,096	498,797	782,824	233,277,921	500,110	680,009	233,957,929	501,681	1,158,966	235,116,896	503,656	3,550,850	238,667,745	508,713
Washington	WA	2.371%	46,547,543	91,998	264,909	46,812,451	92,245	7,467	46,819,918	92,515	(24,443)	46,795,475	92,498	334,676	47,130,151	92,804
Eastern Wyoming	WYP	2.539%	86,360,751	182,186	186,412	86,547,162	182,916	300,225	86,847,388	183,431	863,318	87,710,706	184,662	1,164,488	88,875,194	186,807
Utah	UT	2.215%	268,413,920	494,198	1,857,229	270,271,149	497,128	1,853,285	272,124,434	500,553	1,610,688	273,735,122	503,749	3,972,042	277,707,164	508,901
Idaho	ID	1.990%	53,844,700	89,159	98,136	53,942,836	89,365	150,448	54,093,284	89,571	217,098	54,310,382	89,876	574,710	54,885,092	90,532
Western Wyoming	WYU	2.182%	17,757,052	32,317	(31,708)	17,725,345	32,260	(31,708)	17,693,637	32,202	(31,708)	17,661,930	32,144	(31,708)	17,630,222	32,087
Pre-merger Pacific	SG	2.093%	812,474	1,429	(13,917)	798,556	1,405	(13,917)	784,639	1,381	(13,917)	770,722	1,357	(13,917)	756,805	1,332
Pre-merger Utah	SG	1.231%	2,391,098	2,468	(30,778)	2,360,320	2,437	(30,778)	2,329,541	2,405	(30,778)	2,298,763	2,374	(30,778)	2,267,985	2,342
Post-merger	SG	3.438%	304,457,412	872,564	66,636	304,524,048	872,258	218,262	304,742,310	872,666	1,343,547	306,085,857	874,903	5,607,129	311,692,986	884,859
General Office	SO	5.656%	393,695,905	1,856,124	638,391	394,334,296	1,857,224	3,427,081	397,761,378	1,866,805	236,944	397,998,322	1,875,441	6,911,058	404,909,380	1,892,287
General Office	SG	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
General Office	SG	3.982%	223,232	741	-	223,232	741	-	223,232	741	-	223,232	741	-	223,232	741
Customer Service	CN	5.953%	15,903,591	79,143	(99,428)	15,804,162	78,650	(99,428)	15,704,734	78,156	(99,428)	15,605,305	77,663	(99,428)	15,505,877	77,170
Fuel Related	SE	3.632%	3,110,131	9,437	(14,898)	3,095,234	9,392	(14,898)	3,080,336	9,347	(14,898)	3,065,439	9,302	(14,898)	3,050,541	9,257
Total General Plant			1,448,931,912	4,248,891.90	3,796,939	1,452,728,852	4,254,811.04	6,512,024	1,459,240,876	4,270,267.68	5,261,992	1,464,502,868	4,287,273.13	22,254,033	1,486,756,901	4,327,057.50
Mining Plant:																
Coal Mine	SE	0.000%	1,822,901	-	-	1,822,901	-	-	1,822,901	-	-	1,822,901	-	-	1,822,901	-
Total Mining Plant			1,822,901	-	-	1,822,901	-	-	1,822,901	-	-	1,822,901	-	-	1,822,901	-
Total Depreciation Expense			31,025,393,342	91,309,910	45,263,623	31,070,656,965	91,380,357	78,055,090	31,148,712,055	91,496,200	93,002,982	31,241,715,037	91,694,776	185,139,823	31,426,854,860	92,060,211

PacifiCorp
Oregon General Rate Case - December 2023
Jun 2021 - Dec 2022 Depreciation & Amortization Expense

Description	Factor	2018 Rate	Adjusted EPIS Balance Aug 2022	Depreciation Expense Aug 2022	Adjustments	Adjusted EPIS Balance Sep 2022	Depreciation Expense Sep 2022	Adjustments	Adjusted EPIS Balance Oct 2022	Depreciation Expense Oct 2022	Adjustments	Adjusted EPIS Balance Nov 2022	Depreciation Expense Nov 2022	Adjustments	Adjusted EPIS Balance Dec 2022	Depreciation Expense Dec 2022
AMORTIZATION EXPENSE																
Intangible Plant:																
California	CA	0.367%	481,167	147	-	481,167	147	-	481,167	147	-	481,167	147	-	481,167	147
Customer Service	CN	6.456%	213,770,061	1,150,182	(34,194)	213,735,868	1,149,998	(34,194)	213,701,674	1,149,814	(34,194)	213,667,480	1,149,630	(34,194)	213,633,287	1,149,446
Pre-merger Utah	SG	2.611%	477,596	1,039	-	477,596	1,039	-	477,596	1,039	-	477,596	1,039	-	477,596	1,039
Pre-merger Pacific	SG	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Idaho	ID	0.527%	4,369,938	1,920	(86)	4,369,851	1,920	(86)	4,369,765	1,920	(86)	4,369,679	1,920	(86)	4,369,593	1,919
Oregon	OR	0.254%	4,610,916	974	(363)	4,610,553	974	(363)	4,610,189	974	(363)	4,609,826	974	(363)	4,609,463	974
Fuel Related	SE	20.000%	(48,006)	(766)	(4,079)	(52,085)	(834)	(4,079)	(56,164)	(902)	(4,079)	(60,244)	(970)	(4,079)	(64,323)	(1,038)
Post-merger	SG	3.402%	209,802,260	594,904	(62,928)	209,739,332	594,725	(62,928)	209,676,404	594,547	(62,928)	209,613,477	594,368	(62,928)	209,550,549	594,190
Hydro Relicensing	SG-P	2.593%	103,389,757	223,401	(4,666)	103,385,091	223,391	(4,666)	103,380,425	223,381	(4,666)	103,375,760	223,371	(4,666)	103,371,094	223,361
Hydro Relicensing	SG-U	3.225%	9,806,011	26,376	(14,920)	9,791,091	26,336	(14,920)	9,776,170	26,296	(14,920)	9,761,250	26,256	(14,920)	9,746,329	26,216
General Office	SO	6.156%	461,582,927	2,368,714	3,595,362	465,178,289	2,376,952	(475,199)	464,703,089	2,384,954	1,409,031	466,112,120	2,387,349	10,676,514	476,788,634	2,418,346
Utah	UT	-0.148%	(26,170,458)	3,233	(561)	(26,171,019)	3,233	(561)	(26,171,581)	3,233	(561)	(26,172,142)	3,233	(561)	(26,172,704)	3,233
Washington	WA	0.155%	2,036,986	262	-	2,036,986	262	-	2,036,986	262	-	2,036,986	262	-	2,036,986	262
Eastern Wyoming	WYP	1.960%	5,560,780	9,090	(7,729)	5,553,052	9,078	(7,729)	5,545,323	9,065	(7,729)	5,537,594	9,052	(7,729)	5,529,866	9,040
Western Wyoming	WYU	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Klamath		0.000%	74,111,750		-	74,111,750		-	74,111,750		-	74,111,750		-	74,111,750	
Total Intangible Plant			1,063,781,685	4,379,477	3,465,835	1,067,247,521	4,387,221	(604,726)	1,066,642,795	4,394,730	1,279,504	1,067,922,300	4,396,632	10,546,987	1,078,469,287	4,427,136
Hydro Production Plant:																
Pre-merger Pacific	SG	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG-P	2.126%	14,658,989	25,975	-	14,658,989	25,975	-	14,658,989	25,975	-	14,658,989	25,975	-	14,658,989	25,975
Post-merger	SG-U	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Hydro Plant			14,658,989	25,975	-	14,658,989	25,975	-	14,658,989	25,975	-	14,658,989	25,975	-	14,658,989	25,975
Other Production Plant:																
Post-merger	SG	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Other Plant			-	-	-	-	-	-	-	-	-	-	-	-	-	-
General Plant:																
California	CA	0.000%	505,860	-	-	505,860	-	-	505,860	-	-	505,860	-	-	505,860	-
General Office	CN	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Oregon	OR	5.852%	5,517,847	26,909	-	5,517,847	26,909	-	5,517,847	26,909	-	5,517,847	26,909	-	5,517,847	26,909
General Office	SO	5.965%	1,815,339	9,024	-	1,815,339	9,024	-	1,815,339	9,024	-	1,815,339	9,024	-	1,815,339	9,024
Utah	UT	0.000%	33,127	-	-	33,127	-	-	33,127	-	-	33,127	-	-	33,127	-
Washington	WA	3.801%	2,532,816	8,022	-	2,532,816	8,022	-	2,532,816	8,022	-	2,532,816	8,022	-	2,532,816	8,022
Eastern Wyoming	WYP	1.161%	4,580,607	4,431	-	4,580,607	4,431	-	4,580,607	4,431	-	4,580,607	4,431	-	4,580,607	4,431
Western Wyoming	WYU	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total General Plant			14,985,595	48,386.18	-	14,985,595	48,386.18	-	14,985,595	48,386.18	-	14,985,595	48,386.18	-	14,985,595	48,386.18
Total Amortization			1,093,426,270	4,453,838	3,465,835	1,096,892,105	4,461,582	(604,726)	1,096,287,379	4,469,091	1,279,504	1,097,566,884	4,470,993	10,546,987	1,108,113,871	4,501,497
Total Depreciation & Amortization			32,118,819,612	95,763,748	48,729,458	32,167,549,070	95,841,939	77,450,364	32,244,999,434	95,965,291	94,282,486	32,339,281,921	96,165,769	195,686,811	32,534,968,731	96,561,707

PacifiCorp
Oregon General Rate Case - December 2023
Jun 2021 - Dec 2022 Depreciation & Amortization Expense

Description	Factor	2018 Rate	Test Period Depreciation Expense
DEPRECIATION EXPENSE			
Steam Production Plant:			
Pre-merger Pacific	SG	6.692%	67,261,085
Pre-merger Utah	SG	5.015%	52,632,126
Post-merger	SG	6.992%	340,167,064
Geothermal - Blundell	SG	6.992%	2,055,827
Carbon	SG		-
Pollution Control Equipment	SG	6.992%	-
Pollution Control Equipment	SG	0.000%	-
Post-merger	SG	0.000%	-
Total Steam Plant			462,116,102
Hydro Production Plant:			
Pre-merger Pacific	SG	2.210%	4,043,093
Pre-merger Utah	SG	3.181%	1,249,428
Post-merger	SG-P	2.741%	19,524,790
Post-merger	SG-U	4.692%	8,599,880
Klamath - New Capital	SG-P	20.000%	1,929,533
Klamath		0.000%	-
Total Hydro Plant			35,346,724
Other Production Plant:			
Pre-merger Utah	SG	0.000%	-
Post-merger	SG	3.503%	68,522,352
Post-merger Wind	SG-W	4.223%	137,093,159
Black Cap Solar	OR	0.000%	-
Post-merger	SG	4.825%	4,322,762
Total Other Plant			209,938,272
Transmission Plant:			
Pre-merger Pacific	SG	1.700%	8,104,707
Pre-merger Utah	SG	1.673%	10,294,556
Post-merger	SG	1.724%	119,830,885
Total Transmission Plant			138,230,148
Distribution Plant:			
California	CA	2.704%	9,254,102
Oregon	OR	2.271%	56,428,045
Washington	WA	2.588%	16,032,588
Eastern Wyoming	WYP	2.685%	19,227,174
Utah	UT	2.540%	93,266,338
Idaho	ID	2.561%	11,380,194
Western Wyoming	WYU	2.682%	4,144,520
Total Distribution Plant			209,732,961
General Plant:			
California	CA	2.021%	474,036
Oregon	OR	2.577%	6,150,304
Washington	WA	2.371%	1,117,620
Eastern Wyoming	WYP	2.539%	2,256,466
Utah	UT	2.215%	6,150,804
Idaho	ID	1.990%	1,092,107
Western Wyoming	WYU	2.182%	384,695
Pre-merger Pacific	SG	2.093%	15,841
Pre-merger Utah	SG	1.231%	27,917
Post-merger	SG	3.438%	10,714,682
General Office	SO	5.656%	22,902,899
General Office	SG	0.000%	-
General Office	SG	3.982%	8,888
Customer Service	CN	5.953%	923,079
Fuel Related	SE	3.632%	110,810
Total General Plant			52,330,149
Mining Plant:			
Coal Mine	SE	0.000%	-
Total Mining Plant			-
Total Depreciation Expense			1,107,694,357

PacifiCorp
Oregon General Rate Case - December 2023
Jun 2021 - Dec 2022 Depreciation & Amortization Expense

Description	Factor	2018 Rate	Test Period Depreciation Expense
AMORTIZATION EXPENSE			
Intangible Plant:			
California	CA	0.367%	1,765
Customer Service	CN	6.456%	13,792,251
Pre-merger Utah	SG	2.611%	12,470
Pre-merger Pacific	SG	0.000%	-
Idaho	ID	0.527%	23,033
Oregon	OR	0.254%	11,687
Fuel Related	SE	20.000%	(12,865)
Post-merger	SG	3.402%	7,129,208
Hydro Relicensing	SG-P	2.593%	2,680,267
Hydro Relicensing	SG-U	3.225%	314,346
General Office	SO	6.156%	29,348,751
Utah	UT	-0.148%	38,802
Washington	WA	0.155%	3,148
Eastern Wyoming	WYP	1.960%	108,401
Western Wyoming	WYU	0.000%	-
Klamath		0.000%	-
Total Intangible Plant			53,451,266
Hydro Production Plant:			
Pre-merger Pacific	SG	0.000%	-
Post-merger	SG-P	2.126%	311,696
Post-merger	SG-U	0.000%	-
Total Hydro Plant			311,696
Other Production Plant:			
Post-merger	SG	0.000%	-
Total Other Plant			-
General Plant:			
California	CA	0.000%	-
General Office	CN	0.000%	-
Oregon	OR	5.852%	322,905
General Office	SO	5.965%	108,292
Utah	UT	0.000%	-
Washington	WA	3.801%	96,268
Eastern Wyoming	WYP	1.161%	53,169
Western Wyoming	WYU	0.000%	-
Total General Plant			580,634
Total Amortization			54,343,596
Total Depreciation & Amortization			1,162,037,953
			Ref. 6.1.3
			1,162,037,953

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	26.070%	(24,423,471)	
Steam Depreciation Reserve	108SP	3	(69,456,778)	SG	26.070%	(18,107,620)	
Steam Depreciation Reserve	108SP	3	(1,335,136,315)	SG	26.070%	(348,074,604)	
Steam Depreciation Reserve	108SP	3	-	SG	26.070%	-	
Hydro Depreciation Reserve	108HP	3	23,341,096	SG-P	26.070%	6,085,104	
Hydro Depreciation Reserve	108HP	3	(1,290,381)	SG-U	26.070%	(336,407)	
Hydro Depreciation Reserve	108HP	3	(53,037,520)	SG-P	26.070%	(13,827,063)	
Hydro Depreciation Reserve	108HP	3	(10,810,908)	SG-U	26.070%	(2,818,441)	
Other Depreciation Reserve	108OP	3	-	SG	26.070%	-	
Other Depreciation Reserve	108OP	3	(63,870,472)	SG	26.070%	(16,651,250)	
Other Depreciation Reserve	108OP	3	(199,200,573)	SG-W	26.070%	(51,932,271)	
Other Depreciation Reserve	108OP	3	-	OR	Situs	-	
Other Depreciation Reserve	108OP	3	(5,629,717)	SG	26.070%	(1,467,686)	
Transmission Depreciation Reserve	108TP	3	(9,151,224)	SG	26.070%	(2,385,755)	
Transmission Depreciation Reserve	108TP	3	(10,160,453)	SG	26.070%	(2,648,865)	
Transmission Depreciation Reserve	108TP	3	(154,513,575)	SG	26.070%	(40,282,217)	
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	26.070%	50,234	
General Depreciation Reserve	108GP	3	382,208	SG	26.070%	99,643	
General Depreciation Reserve	108GP	3	(12,094,928)	SG	26.070%	(3,153,189)	
General Depreciation Reserve	108GP	3	(9,553,108)	SO	27.173%	(2,595,874)	
General Depreciation Reserve	108GP	3	-	SG	26.070%	-	
General Depreciation Reserve	108GP	3	(17,612)	SG	26.070%	(4,591)	
General Depreciation Reserve	108GP	3	360,700	CN	30.990%	111,781	
General Depreciation Reserve	108GP	3	43,824	SE	25.068%	10,986	
Mining Depreciation Reserve	108MP	3	-	SE	25.068%	-	
			(2,225,728,915)			(569,440,273)	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.

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	26.070%	(8,128)	
Intangible Amortization Reserve	111IP	3	(10,998)	OR	Situs	(10,998)	
Intangible Amortization Reserve	111IP	3	86,607	SE	25.068%	21,711	
Intangible Amortization Reserve	111IP	3	(9,577,171)	SG	26.070%	(2,496,801)	
Intangible Amortization Reserve	111IP	3	(3,937,327)	SG-P	26.070%	(1,026,475)	
Intangible Amortization Reserve	111IP	3	(206,561)	SG-U	26.070%	(53,851)	
Intangible Amortization Reserve	111IP	3	(22,536,499)	SO	27.173%	(6,123,861)	
Intangible Amortization Reserve	111IP	3	-	SG	26.070%	-	
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	26.070%	-	
Hydro Amortization Reserve	111HP	3	-	SG	26.070%	-	
Hydro Amortization Reserve	111HP	3	(467,544)	SG-P	26.070%	(121,890)	
Hydro Amortization Reserve	111HP	3	-	SG-U	26.070%	-	
Other Amortization Reserve	111OP	3	-	SG	26.070%	-	
General Amortization Reserve	111GP	3	-	CA	Situs	-	
General Amortization Reserve	111GP	3	-	CN	30.990%	-	
General Amortization Reserve	111GP	3	-	SG	26.070%	-	
General Amortization Reserve	111GP	3	(484,357)	OR	Situs	(484,357)	
General Amortization Reserve	111GP	3	(162,438)	SO	27.173%	(44,139)	
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)			(16,574,495)	6.2.3
Total Adjustment			(2,283,493,634)			(586,014,768)	

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.

PacifiCorp
Oregon General Rate Case - December 2023
Depreciation and Amortization Reserve Summary

Description	Account	Factor	12 ME Jun 2021 Reserve	Test Period Reserve	Adjustment to Test Period
DEPRECIATION RESERVE					
Steam Production Plant:					
Pre-merger Pacific	108SP	SG	(749,221,847)	(842,904,819)	(93,682,972)
Pre-merger Utah	108SP	SG	(719,880,716)	(789,337,495)	(69,456,778)
Post-merger	108SP	SG	(1,901,219,938)	(3,236,356,253)	(1,335,136,315)
Post-merger	108SP	SG	-	-	-
Total Steam Plant			(3,370,322,501)	(4,868,598,566)	(1,498,276,065)
Hydro Production Plant:					
Pre-merger Pacific	108HP	SG-P	(169,356,335)	(146,015,239)	23,341,096
Pre-merger Utah	108HP	SG-U	(31,496,322)	(32,786,703)	(1,290,381)
Post-merger	108HP	SG-P	(233,526,380)	(286,563,901)	(53,037,520)
Post-merger	108HP	SG-U	(62,385,722)	(73,196,630)	(10,810,908)
Total Hydro Plant			(496,764,760)	(538,562,473)	(41,797,713)
Other Production Plant:					
Pre-merger Utah	108OP	SG	-	-	-
Post-merger	108OP	SG	(482,707,852)	(546,578,324)	(63,870,472)
Post-merger - Wind	108OP	SG-W	383,543,335	184,342,762	(199,200,573)
Black Cap Solar	108OP	OR	-	-	-
Post-merger	108OP	SG	(43,837,829)	(49,467,546)	(5,629,717)
Total Other Plant			(143,002,346)	(411,703,108)	(268,700,761)
Transmission Plant:					
Pre-merger Pacific	108TP	SG	(353,157,214)	(362,308,437)	(9,151,224)
Pre-merger Utah	108TP	SG	(426,788,101)	(436,948,554)	(10,160,453)
Post-merger	108TP	SG	(1,221,447,907)	(1,375,961,482)	(154,513,575)
Total Transmission Plant			(2,001,393,221)	(2,175,218,473)	(173,825,252)
Distribution Plant:					
California	108364	CA	(150,707,932)	(160,244,726)	(9,536,795)
Oregon	108364	OR	(1,085,987,789)	(1,123,110,646)	(37,122,857)
Washington	108364	WA	(273,678,015)	(290,502,417)	(16,824,402)
Eastern Wyoming	108364	WYP	(289,764,719)	(308,800,678)	(19,035,960)
Utah	108364	UT	(1,071,716,019)	(1,167,331,507)	(95,615,488)
Idaho	108364	ID	(158,999,969)	(171,059,258)	(12,059,288)
Western Wyoming	108364	WYU	(62,150,629)	(67,872,874)	(5,722,245)
Total Distribution Plant			(3,093,005,071)	(3,288,922,105)	(195,917,035)
General Plant:					
California	108GP	CA	(7,256,531)	(8,079,361)	(822,830)
Oregon	108GP	OR	(98,593,172)	(108,559,029)	(9,965,858)
Washington	108GP	WA	(24,976,433)	(26,055,958)	(1,079,525)
Eastern Wyoming	108GP	WYP	(27,328,344)	(29,209,202)	(1,880,858)
Utah	108GP	UT	(92,748,344)	(102,336,961)	(9,588,617)
Idaho	108GP	ID	(19,950,503)	(22,473,724)	(2,523,222)
Western Wyoming	108GP	WYU	(6,737,606)	(7,402,553)	(664,947)
Pre-merger Pacific	108GP	SG	(715,242)	(522,557)	192,685
Pre-merger Utah	108GP	SG	(1,951,711)	(1,569,503)	382,208
Post-merger	108GP	SG	(127,433,166)	(139,528,094)	(12,094,928)
General Office	108GP	SO	(116,526,662)	(126,079,770)	(9,553,108)
General Office	108GP	SG	-	-	-
General Office	108GP	SG	(130,406)	(148,018)	(17,612)
Customer Service	108GP	CN	(7,270,206)	(6,909,506)	360,700
Fuel Related	108GP	SE	(1,538,215)	(1,494,391)	43,824
Total General Plant			(533,156,539)	(580,368,628)	(47,212,089)
Mining Plant:					
Coal Mine	108MP	SE	-	-	-
Total Mining Plant			-	-	-
Total Depreciation Reserve			(9,637,644,438)	(11,863,373,353)	**(2,225,728,915)**
					Ref 6.2

PacifiCorp
Oregon General Rate Case - December 2023
Depreciation and Amortization Reserve Summary

Description	Account	Factor	12 ME Jun 2021 Reserve	Test Period Reserve	Adjustment to Test Period
AMORTIZATION RESERVE					
Intangible Plant:					
California	111IP	CA	(6,202)	(8,850)	(2,648)
Customer Service	111IP	CN	(162,639,670)	(182,729,117)	(20,089,447)
Idaho	111IP	ID	(976,939)	(1,020,506)	(43,567)
Pre-merger Utah	111IP	SG	(397,058)	(428,234)	(31,176)
Oregon	111IP	OR	(129,177)	(140,175)	(10,998)
Fuel Related	111IP	SE	(1,897)	84,709	86,607
Post-merger	111IP	SG	(105,977,548)	(115,554,719)	(9,577,171)
Hydro Relicensing	111IP	SG-P	(114,544,697)	(118,482,024)	(3,937,327)
Hydro Relicensing	111IP	SG-U	(5,755,401)	(5,961,962)	(206,561)
General Office	111IP	SO	(316,598,295)	(339,134,793)	(22,536,499)
Pre-merger Pacific	111IP	SG	-	-	-
Utah	111IP	UT	31,976,724	31,928,632	(48,092)
Washington	111IP	WA	(10,692)	(15,414)	(4,722)
Eastern Wyoming	111IP	WYP	(375,132)	(399,756)	(24,624)
Western Wyoming	111IP	WYU	-	-	-
General Office	111IP	SG	-	-	-
Total Intangible Plant			(675,435,985)	(731,862,209)	(56,426,225)
Hydro Production Plant:					
Pre-merger Pacific	111HP	SG	-	-	-
Post-merger	111HP	SG-P	(3,139,235)	(3,606,778)	(467,544)
Post-merger	111HP	SG-U	-	-	-
Total Hydro Plant			(3,139,235)	(3,606,778)	(467,544)
Other Production Plant:					
Post-merger	111OP	SG	-	-	-
Total Other Plant			-	-	-
General Plant:					
California	111GP	CA	(505,860)	(505,860)	-
General Office	111GP	CN	-	-	-
Idaho	111GP	ID	(333,771)	(333,771)	-
Oregon	111GP	OR	(4,741,005)	(5,225,362)	(484,357)
General Office	111GP	SO	(1,174,857)	(1,337,295)	(162,438)
Utah	111GP	UT	(33,127)	(33,127)	-
Washington	111GP	WA	(1,855,482)	(1,999,885)	(144,403)
Eastern Wyoming	111GP	WYP	(4,454,478)	(4,534,231)	(79,754)
Western Wyoming	111GP	WYU	-	-	-
Total General Plant			(13,098,578)	(13,969,530)	(870,951)
Total Amortization Reserve			(691,673,798)	(749,438,517)	**(57,764,719)**
					Ref 6.2.1
Total Depreciation & Amortization Reserve			(10,329,318,236)	(12,612,811,871)	(2,283,493,634)
				Ref. 6.2.9	

PacifiCorp
Oregon General Rate Case - December 2023
Jun 2021 - December 2022 Depreciation & Amortization Reserve

Description	Factor	Adjusted Reserve Balance Jun 2021	Adjustments	Adjusted Reserve Balance Jul 2021	Adjustments	Adjusted Reserve Balance Aug 2021	Adjustments	Adjusted Reserve Balance Sep 2021	Adjustments	Adjusted Reserve Balance Oct 2021	Adjustments	Adjusted Reserve Balance Nov 2021	Adjustments	Adjusted Reserve Balance Dec 2021	Adjustments
DEPRECIATION RESERVE															
Steam Production Plant:															
Pre-merger Pacific	SG	(749,221,847)	(5,233,328)	(754,455,175)	(5,231,030)	(759,686,205)	(5,228,733)	(764,914,938)	(5,226,435)	(770,141,373)	(5,224,138)	(775,365,511)	(5,221,840)	(780,587,352)	(5,219,543)
Pre-merger Utah	SG	(719,880,716)	(3,886,844)	(723,767,560)	(3,884,593)	(727,652,154)	(3,882,343)	(731,534,497)	(3,880,092)	(735,414,588)	(3,877,841)	(739,292,430)	(3,875,590)	(743,168,020)	(3,873,340)
Post-merger	SG	(2,794,088,362)	(23,499,216)	(2,817,587,578)	(23,492,813)	(2,841,080,391)	(23,482,780)	(2,864,563,171)	(23,506,336)	(2,888,069,507)	(23,536,757)	(2,911,606,264)	(23,559,421)	(2,935,165,685)	(23,572,366)
Geothermal - Blundell	SG	(10,240,252)	(171,319)	(10,411,571)	(171,319)	(10,582,890)	(171,319)	(10,754,209)	(171,319)	(10,925,528)	(171,319)	(11,096,847)	(171,319)	(11,268,165)	(171,319)
Carbon	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Steam Plant		(4,273,431,177)	(32,790,706)	(4,306,221,884)	(32,779,756)	(4,339,001,640)	(32,765,174)	(4,371,766,814)	(32,784,183)	(4,404,550,997)	(32,810,055)	(4,437,361,052)	(32,828,170)	(4,470,189,222)	(32,836,568)
Hydro Production Plant:															
Pre-merger Pacific	SG	(140,844,465)	(288,419)	(141,132,884)	(288,327)	(141,421,211)	(288,235)	(141,709,446)	(288,142)	(141,997,588)	(288,050)	(142,285,638)	(287,958)	(142,573,595)	(287,865)
Pre-merger Utah	SG	(31,496,322)	(72,777)	(31,569,099)	(72,690)	(31,641,789)	(72,603)	(31,714,392)	(72,516)	(31,786,908)	(72,428)	(31,859,336)	(72,341)	(31,931,677)	(72,254)
Post-merger	SG-P	(168,283,208)	(1,117,512)	(169,400,720)	(1,116,763)	(170,517,483)	(1,117,835)	(171,635,318)	(1,121,109)	(172,756,426)	(1,127,316)	(173,883,742)	(1,146,750)	(175,030,492)	(1,161,854)
Post-merger	SG-U	(62,385,722)	(519,924)	(62,905,646)	(520,048)	(63,425,694)	(520,809)	(63,946,503)	(522,225)	(64,468,728)	(525,314)	(64,994,042)	(541,568)	(65,535,610)	(554,980)
Klamath - New Capital	SG-P	(324,034)	(45,065)	(369,098)	(45,065)	(414,163)	(47,406)	(461,569)	(50,359)	(511,928)	(60,244)	(572,173)	(69,519)	(641,692)	(69,519)
Klamath		(93,431,009)	-	(93,431,009)		(93,431,009)	-	(93,431,009)	-	(93,431,009)	-	(93,431,009)	-	(93,431,009)	-
Total Hydro Plant		(496,764,760)	(2,043,697)	(498,808,457)	(2,042,892)	(500,851,349)	(2,046,888)	(502,898,237)	(2,054,350)	(504,952,587)	(2,073,353)	(507,025,940)	(2,118,136)	(509,144,076)	(2,146,472)
Other Production Plant:															
Pre-merger Utah	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG	(482,707,852)	(3,480,877)	(486,188,729)	(3,474,950)	(489,663,679)	(3,469,005)	(493,132,684)	(3,504,630)	(496,637,314)	(3,540,846)	(500,178,160)	(3,536,023)	(503,714,183)	(3,530,719)
Post-merger Wind	SG-W	383,543,335	(10,862,430)	372,680,905	(10,926,631)	361,754,273	(10,958,287)	350,795,986	(11,011,743)	339,784,243	(11,050,540)	328,733,703	(11,062,197)	317,671,506	(11,069,966)
Black Cap Solar	OR	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG	(43,837,829)	(300,707)	(44,138,536)	(303,183)	(44,441,720)	(309,649)	(44,751,369)	(316,114)	(45,067,482)	(315,956)	(45,383,438)	(315,797)	(45,699,235)	(315,633)
Total Other Plant		(143,002,346)	(14,644,015)	(157,646,361)	(14,704,765)	(172,351,126)	(14,736,941)	(187,088,067)	(14,832,487)	(201,920,554)	(14,907,341)	(216,827,895)	(14,914,017)	(231,741,912)	(14,916,318)
Transmission Plant:															
Pre-merger Pacific	SG	(353,157,214)	(511,379)	(353,668,593)	(511,141)	(354,179,734)	(510,903)	(354,690,637)	(510,665)	(355,201,301)	(510,426)	(355,711,728)	(510,188)	(356,221,916)	(509,950)
Pre-merger Utah	SG	(426,788,101)	(569,619)	(427,357,719)	(569,207)	(427,926,926)	(568,795)	(428,495,721)	(568,383)	(429,064,104)	(567,971)	(429,632,075)	(567,559)	(430,199,634)	(567,147)
Post-merger	SG	(1,221,447,907)	(8,178,932)	(1,229,626,839)	(8,185,870)	(1,237,812,709)	(8,198,049)	(1,246,010,758)	(8,239,158)	(1,254,249,916)	(8,296,866)	(1,262,546,782)	(8,353,539)	(1,270,900,321)	(8,383,048)
Total Transmission Plant		(2,001,393,221)	(9,259,930)	(2,010,653,151)	(9,266,218)	(2,019,919,369)	(9,277,747)	(2,029,197,116)	(9,318,205)	(2,038,515,321)	(9,375,264)	(2,047,890,585)	(9,431,286)	(2,057,321,871)	(9,460,145)
Distribution Plant:															
California	CA	(150,707,932)	(448,820)	(151,156,751)	(449,823)	(151,606,574)	(451,902)	(152,058,476)	(454,722)	(152,513,198)	(468,652)	(152,981,850)	(482,591)	(153,464,441)	(484,774)
Oregon	OR	(1,085,987,789)	(1,852,942)	(1,087,840,731)	(1,859,727)	(1,089,700,458)	(1,877,531)	(1,091,577,989)	(1,895,690)	(1,093,473,678)	(1,902,266)	(1,095,375,944)	(1,913,221)	(1,097,289,166)	(1,922,914)
Washington	WA	(273,678,015)	(864,656)	(274,542,671)	(868,009)	(275,410,680)	(870,883)	(276,281,563)	(873,412)	(277,154,975)	(875,227)	(278,030,202)	(877,312)	(278,907,515)	(879,414)
Eastern Wyoming	WYP	(289,764,719)	(989,340)	(290,754,059)	(993,097)	(291,747,156)	(997,161)	(292,744,317)	(1,002,049)	(293,746,365)	(1,006,472)	(294,752,837)	(1,023,466)	(295,776,303)	(1,039,721)
Utah	UT	(1,071,716,019)	(4,830,716)	(1,076,546,735)	(4,852,741)	(1,081,399,476)	(4,884,403)	(1,086,283,879)	(4,930,997)	(1,091,214,876)	(4,964,686)	(1,096,179,561)	(4,999,599)	(1,101,179,161)	(5,035,006)
Idaho	ID	(158,999,969)	(600,219)	(159,600,189)	(602,170)	(160,202,359)	(605,658)	(160,808,017)	(611,833)	(161,419,850)	(623,402)	(162,043,252)	(634,072)	(162,677,324)	(639,520)
Western Wyoming	WYU	(62,150,629)	(318,679)	(62,469,308)	(318,617)	(62,787,924)	(318,554)	(63,106,479)	(318,492)	(63,424,971)	(318,430)	(63,743,401)	(318,368)	(64,061,769)	(318,306)
Total Distribution Plant		(3,093,005,071)	(9,905,372)	(3,102,910,442)	(9,944,184)	(3,112,854,627)	(10,006,092)	(3,122,860,719)	(10,087,195)	(3,132,947,914)	(10,159,135)	(3,143,107,049)	(10,248,630)	(3,153,355,679)	(10,319,654)
General Plant:															
California	CA	(7,256,531)	(44,765)	(7,301,296)	(44,714)	(7,346,010)	(44,673)	(7,390,684)	(44,675)	(7,435,359)	(44,671)	(7,480,030)	(44,613)	(7,524,643)	(44,605)
Oregon	OR	(98,593,172)	(524,682)	(99,117,853)	(524,315)	(99,642,168)	(524,798)	(100,166,967)	(526,686)	(100,693,653)	(528,793)	(101,222,446)	(537,369)	(101,759,815)	(545,320)
Washington	WA	(24,976,433)	(58,825)	(25,035,258)	(58,612)	(25,093,869)	(58,687)	(25,152,556)	(58,955)	(25,211,511)	(59,061)	(25,270,572)	(59,162)	(25,329,734)	(59,225)
Eastern Wyoming	WYP	(27,328,344)	(92,732)	(27,421,076)	(92,445)	(27,513,521)	(92,768)	(27,606,289)	(93,645)	(27,699,934)	(94,411)	(27,794,345)	(97,596)	(27,891,941)	(100,834)
Utah	UT	(92,748,344)	(480,911)	(93,229,255)	(482,809)	(93,712,063)	(485,314)	(94,197,377)	(488,490)	(94,685,868)	(493,239)	(95,179,107)	(501,959)	(95,681,066)	(510,340)
Idaho	ID	(19,950,503)	(136,126)	(20,086,628)	(136,066)	(20,222,694)	(136,126)	(20,358,820)	(136,456)	(20,495,276)	(136,878)	(20,632,154)	(137,992)	(20,770,146)	(139,058)
Western Wyoming	WYU	(6,737,606)	(37,662)	(6,775,268)	(37,605)	(6,812,873)	(37,547)	(6,850,420)	(37,489)	(6,887,909)	(37,432)	(6,925,341)	(37,374)	(6,962,714)	(37,316)
Pre-merger Pacific	SG	(715,242)	10,401	(704,841)	10,426	(694,415)	10,450	(683,965)	10,474	(673,491)	10,498	(662,993)	10,523	(652,470)	10,547
Pre-merger Utah	SG	(1,951,711)	20,839	(1,930,872)	20,871	(1,910,001)	20,902	(1,889,099)	20,934	(1,868,165)	20,965	(1,847,199)	20,997	(1,826,202)	21,029
Post-merger	SG	(127,433,166)	(654,015)	(128,087,181)	(653,178)	(128,740,359)	(652,111)	(129,392,471)	(651,487)	(130,043,958)	(652,068)	(130,696,026)	(659,702)	(131,355,727)	(666,290)
General Office	SO	(116,526,662)	(331,334)	(116,857,996)	(330,485)	(117,188,481)	(342,532)	(117,531,013)	(409,327)	(117,940,340)	(478,395)	(118,418,735)	(508,859)	(118,927,594)	(525,351)
General Office	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-
General Office	SG	(130,406)	(978)	(131,384)	(978)	(132,363)	(978)	(133,341)	(978)	(134,320)	(978)	(135,298)	(978)	(136,277)	(978)
Customer Service	CN	(7,270,206)	13,873	(7,256,333)	14,366	(7,241,966)	14,860	(7,227,107)	15,353	(7,211,754)	15,846	(7,195,907)	16,339	(7,179,568)	16,833
Fuel Related	SE	(1,538,215)	1,871	(1,536,344)	1,916	(1,534,428)	1,961	(1,532,467)	2,006	(1,530,460)	2,051	(1,528,409)	2,096	(1,526,313)	2,142
Total General Plant		(533,156,539)	(2,315,045)	(535,471,584)	(2,313,628)	(537,785,212)	(2,327,363)	(540,112,575)	(2,399,422)	(542,511,997)	(2,476,565)	(544,988,562)	(2,535,649)	(547,524,211)	(2,578,768)
Mining Plant:															
Coal Mine	SE	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Mining Plant		-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Depreciation Reserve		(10,540,753,115)	(70,958,765)	(10,611,711,879)	(71,051,443)	(10,682,763,323)	(71,160,205)	(10,753,923,528)	(71,475,842)	(10,825,399,370)	(71,801,712)	(10,897,201,082)	(72,075,889)	(10,969,276,971)	(72,257,925)

PacifiCorp
Oregon General Rate Case - December 2023
Jun 2021 - December 2022 Depreciation & Amortization Reserve

Description	Factor	Adjusted Reserve Balance Jun 2021	Adjustments	Adjusted Reserve Balance Jul 2021	Adjustments	Adjusted Reserve Balance Aug 2021	Adjustments	Adjusted Reserve Balance Sep 2021	Adjustments	Adjusted Reserve Balance Oct 2021	Adjustments	Adjusted Reserve Balance Nov 2021	Adjustments	Adjusted Reserve Balance Dec 2021	Adjustments
AMORTIZATION RESERVE															
Intangible Plant:															
California	CA	(6,202)	(147)	(6,350)	(147)	(6,497)	(147)	(6,644)	(147)	(6,791)	(147)	(6,938)	(147)	(7,085)	(147)
Customer Service	CN	(162,639,670)	(1,118,380)	(163,758,050)	(1,118,196)	(164,876,246)	(1,118,012)	(165,994,258)	(1,117,828)	(167,112,086)	(1,117,644)	(168,229,730)	(1,117,460)	(169,347,190)	(1,117,276)
Idaho	ID	(976,939)	(1,834)	(978,773)	(1,834)	(980,607)	(1,834)	(982,440)	(1,834)	(984,274)	(1,834)	(986,108)	(1,834)	(987,942)	(1,834)
Pre-merger Utah	SG	(397,058)	(1,039)	(398,098)	(1,039)	(399,137)	(1,039)	(400,176)	(1,039)	(401,215)	(1,039)	(402,254)	(1,039)	(403,294)	(1,039)
Montana	MT	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Oregon	OR	(129,177)	(612)	(129,789)	(612)	(130,400)	(612)	(131,012)	(612)	(131,624)	(612)	(132,236)	(612)	(132,847)	(612)
Fuel Related	SE	(1,897)	3,962	2,064	4,030	6,094	4,098	10,191	4,166	14,357	4,234	18,591	4,302	22,892	4,370
Post-merger	SG	(105,977,548)	(534,295)	(106,511,843)	(534,117)	(107,045,960)	(533,938)	(107,579,898)	(533,760)	(108,113,658)	(533,582)	(108,647,240)	(533,403)	(109,180,643)	(533,225)
Hydro Relicensing	SG-P	(40,432,947)	(218,866)	(40,651,813)	(218,856)	(40,870,670)	(218,846)	(41,089,516)	(218,836)	(41,308,352)	(218,826)	(41,527,178)	(218,816)	(41,745,994)	(218,806)
Hydro Relicensing	SG-U	(5,755,401)	(11,977)	(5,767,378)	(11,937)	(5,779,315)	(11,897)	(5,791,212)	(11,857)	(5,803,068)	(11,816)	(5,814,885)	(11,776)	(5,826,661)	(11,736)
General Office	SO	(316,598,295)	(1,096,611)	(317,694,906)	(1,095,211)	(318,790,117)	(1,095,336)	(319,885,453)	(1,101,264)	(320,986,716)	(1,121,719)	(322,108,436)	(1,154,558)	(323,262,994)	(1,175,581)
Pre-merger Pacific	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Utah	UT	31,976,724	(2,671)	31,974,053	(2,671)	31,971,382	(2,671)	31,968,711	(2,671)	31,966,040	(2,671)	31,963,369	(2,671)	31,960,697	(2,671)
Washington	WA	(10,692)	(262)	(10,954)	(262)	(11,216)	(262)	(11,479)	(262)	(11,741)	(262)	(12,003)	(262)	(12,266)	(262)
Eastern Wyoming	WYP	(375,132)	(1,526)	(376,658)	(1,513)	(378,171)	(1,501)	(379,672)	(1,488)	(381,160)	(1,475)	(382,635)	(1,463)	(384,098)	(1,450)
Western Wyoming	WYU	-	-	-	-	-	-	-	-	-	-	-	-	-	-
General Office	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Klamath		(74,111,750)	-	(74,111,750)	-	(74,111,750)	-	(74,111,750)	-	(74,111,750)	-	(74,111,750)	-	(74,111,750)	-
Total Intangible Plant		(675,435,985)	(2,984,259)	(678,420,244)	(2,982,366)	(681,402,609)	(2,981,997)	(684,384,607)	(2,987,432)	(687,372,039)	(3,007,394)	(690,379,433)	(3,039,740)	(693,419,173)	(3,060,269)
Hydro Production Plant:															
Pre-merger Pacific	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG-P	(3,139,235)	(25,975)	(3,165,210)	(25,975)	(3,191,184)	(25,975)	(3,217,159)	(25,975)	(3,243,133)	(25,975)	(3,269,108)	(25,975)	(3,295,083)	(25,975)
Post-merger	SG-U	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Hydro Plant		(3,139,235)	(25,975)	(3,165,210)	(25,975)	(3,191,184)	(25,975)	(3,217,159)	(25,975)	(3,243,133)	(25,975)	(3,269,108)	(25,975)	(3,295,083)	(25,975)
Other Production Plant:															
Post-merger	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Other Plant		-	-	-	-	-	-	-	-	-	-	-	-	-	-
General Plant:															
California	CA	(505,860)	-	(505,860)	-	(505,860)	-	(505,860)	-	(505,860)	-	(505,860)	-	(505,860)	-
General Office	CN	-	-	-	-	-	-	-	-	-	-	-	-	-	-
General Office	ID	(333,771)	-	(333,771)	-	(333,771)	-	(333,771)	-	(333,771)	-	(333,771)	-	(333,771)	-
Oregon	OR	(4,741,005)	(26,909)	(4,767,913)	(26,909)	(4,794,822)	(26,909)	(4,821,731)	(26,909)	(4,848,640)	(26,909)	(4,875,548)	(26,909)	(4,902,457)	(26,909)
General Office	SO	(1,174,857)	(9,024)	(1,183,881)	(9,024)	(1,192,905)	(9,024)	(1,201,930)	(9,024)	(1,210,954)	(9,024)	(1,219,978)	(9,024)	(1,229,003)	(9,024)
Utah	UT	(33,127)	-	(33,127)	-	(33,127)	-	(33,127)	-	(33,127)	-	(33,127)	-	(33,127)	-
Washington	WA	(1,855,482)	(8,022)	(1,863,504)	(8,022)	(1,871,527)	(8,022)	(1,879,549)	(8,022)	(1,887,572)	(8,022)	(1,895,594)	(8,022)	(1,903,616)	(8,022)
Eastern Wyoming	WYP	(4,454,478)	(4,431)	(4,458,908)	(4,431)	(4,463,339)	(4,431)	(4,467,770)	(4,431)	(4,472,201)	(4,431)	(4,476,632)	(4,431)	(4,481,062)	(4,431)
Western Wyoming	WYU	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total General Plant		(13,098,578)	(48,386)	(13,146,965)	(48,386)	(13,195,351)	(48,386)	(13,243,737)	(48,386)	(13,292,123)	(48,386)	(13,340,509)	(48,386)	(13,388,895)	(48,386)
Total Amortization Reserve		(691,673,798)	(3,058,620)	(694,732,418)	(3,056,727)	(697,789,144)	(3,056,358)	(700,845,503)	(3,061,793)	(703,907,295)	(3,081,755)	(706,989,051)	(3,114,101)	(710,103,152)	(3,134,630)
Total Depreciation & Amortization Reserve		(11,232,426,913)	(74,017,384)	(11,306,444,297)	(74,108,170)	(11,380,552,467)	(74,216,563)	(11,454,769,030)	(74,537,635)	(11,529,306,666)	(74,883,467)	(11,604,190,133)	(75,189,990)	(11,679,380,123)	(75,392,556)

PacifiCorp
Oregon General Rate Case - December 2023
Jun 2021 - December 2022 Depreciation & Amortization Reserve

Description	Factor	Adjusted Reserve Balance Jan 2022	Adjustments	Adjusted Reserve Balance Feb 2022	Adjustments	Adjusted Reserve Balance Mar 2022	Adjustments	Adjusted Reserve Balance Apr 2022	Adjustments	Adjusted Reserve Balance May 2022	Adjustments	Adjusted Reserve Balance Jun 2022	Adjustments	Adjusted Reserve Balance Jul 2022	Adjustments
DEPRECIATION RESERVE															
Steam Production Plant:															
Pre-merger Pacific	SG	(785,806,895)	(5,217,246)	(791,024,140)	(5,214,948)	(796,239,088)	(5,212,651)	(801,451,739)	(5,210,353)	(806,662,092)	(5,208,056)	(811,870,148)	(5,205,758)	(817,075,906)	(5,203,461)
Pre-merger Utah	SG	(747,041,360)	(3,871,089)	(750,912,449)	(3,868,838)	(754,781,287)	(3,866,587)	(758,647,874)	(3,864,337)	(762,512,211)	(3,862,086)	(766,374,297)	(3,859,835)	(770,234,133)	(3,857,585)
Post-merger	SG	(2,958,738,051)	(23,551,739)	(2,982,289,790)	(23,533,035)	(3,005,822,825)	(23,583,831)	(3,029,406,656)	(23,739,969)	(3,053,146,625)	(23,869,336)	(3,077,015,961)	(23,910,286)	(3,100,926,247)	(23,908,451)
Geothermal - Blundell	SG	(11,439,484)	(171,319)	(11,610,803)	(171,319)	(11,782,122)	(171,319)	(11,953,441)	(171,319)	(12,124,760)	(171,319)	(12,296,079)	(171,319)	(12,467,398)	(171,319)
Carbon	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Steam Plant		(4,503,025,790)	(32,811,393)	(4,535,837,182)	(32,788,140)	(4,568,625,323)	(32,834,388)	(4,601,459,711)	(32,985,978)	(4,634,445,689)	(33,110,797)	(4,667,556,485)	(33,147,199)	(4,700,703,684)	(33,140,815)
Hydro Production Plant:															
Pre-merger Pacific	SG	(142,861,461)	(287,773)	(143,149,234)	(287,681)	(143,436,914)	(287,588)	(143,724,503)	(287,496)	(144,011,999)	(287,404)	(144,299,402)	(287,311)	(144,586,714)	(287,219)
Pre-merger Utah	SG	(32,003,932)	(72,167)	(32,076,099)	(72,080)	(32,148,179)	(71,993)	(32,220,171)	(71,906)	(32,292,077)	(71,819)	(32,363,896)	(71,731)	(32,435,627)	(71,644)
Post-merger	SG-P	(176,192,346)	(1,164,749)	(177,357,095)	(1,169,163)	(178,526,257)	(1,170,741)	(179,696,998)	(1,171,636)	(180,868,634)	(1,185,695)	(182,054,329)	(1,199,297)	(183,253,626)	(1,207,564)
Post-merger	SG-U	(66,090,590)	(554,582)	(66,645,172)	(554,185)	(67,199,357)	(553,788)	(67,753,145)	(553,391)	(68,306,536)	(553,129)	(68,859,665)	(555,267)	(69,414,932)	(557,269)
Klamath - New Capital	SG-P	(711,211)	(69,519)	(780,729)	(69,519)	(850,248)	(69,519)	(919,767)	(69,519)	(989,286)	(69,519)	(1,058,805)	(69,519)	(1,128,324)	(69,519)
Klamath		(93,431,009)	-	(93,431,009)	-	(93,431,009)	-	(93,431,009)	-	(93,431,009)	-	(93,431,009)	-	(93,431,009)	-
Total Hydro Plant		(511,290,548)	(2,148,790)	(513,439,338)	(2,152,627)	(515,591,965)	(2,153,629)	(517,745,594)	(2,153,947)	(519,899,541)	(2,167,565)	(522,067,106)	(2,183,126)	(524,250,232)	(2,193,215)
Other Production Plant:															
Pre-merger Utah	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG	(507,244,902)	(3,524,697)	(510,769,600)	(3,518,675)	(514,288,275)	(3,546,832)	(517,835,107)	(3,580,186)	(521,415,293)	(3,580,730)	(524,996,023)	(3,576,433)	(528,572,457)	(3,570,777)
Post-merger Wind	SG-W	306,601,540	(11,073,494)	295,528,047	(11,077,022)	284,451,025	(11,080,549)	273,370,476	(11,084,174)	262,286,302	(11,087,798)	251,198,504	(11,091,326)	240,107,178	(11,094,854)
Black Cap Solar	OR	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG	(46,014,868)	(315,464)	(46,330,332)	(315,294)	(46,645,626)	(315,125)	(46,960,751)	(314,955)	(47,275,706)	(314,831)	(47,590,537)	(314,706)	(47,905,243)	(314,537)
Total Other Plant		(246,658,230)	(14,913,655)	(261,571,885)	(14,910,991)	(276,482,876)	(14,942,506)	(291,425,382)	(14,979,316)	(306,404,697)	(14,983,359)	(321,388,057)	(14,982,466)	(336,370,522)	(14,980,167)
Transmission Plant:															
Pre-merger Pacific	SG	(356,731,866)	(509,712)	(357,241,578)	(509,473)	(357,751,051)	(509,235)	(358,260,286)	(508,997)	(358,769,283)	(508,759)	(359,278,042)	(508,520)	(359,786,562)	(508,282)
Pre-merger Utah	SG	(430,766,781)	(566,735)	(431,333,516)	(566,323)	(431,899,839)	(565,911)	(432,465,751)	(565,499)	(433,031,250)	(565,088)	(433,596,337)	(564,676)	(434,161,013)	(564,264)
Post-merger	SG	(1,279,283,370)	(8,388,183)	(1,287,671,553)	(8,397,049)	(1,296,068,601)	(8,410,722)	(1,304,479,323)	(8,438,948)	(1,312,918,271)	(8,472,711)	(1,321,390,982)	(8,513,809)	(1,329,904,791)	(8,552,884)
Total Transmission Plant		(2,066,782,016)	(9,464,630)	(2,076,246,646)	(9,472,845)	(2,085,719,492)	(9,485,868)	(2,095,205,360)	(9,513,444)	(2,104,718,804)	(9,546,557)	(2,114,265,361)	(9,587,005)	(2,123,852,366)	(9,625,430)
Distribution Plant:															
California	CA	(153,949,215)	(487,112)	(154,436,326)	(492,724)	(154,929,050)	(498,155)	(155,427,205)	(505,589)	(155,932,793)	(519,464)	(156,452,258)	(532,650)	(156,984,907)	(539,061)
Oregon	OR	(1,099,212,079)	(1,926,249)	(1,101,138,328)	(1,940,927)	(1,103,079,255)	(1,958,923)	(1,105,038,178)	(1,989,999)	(1,107,028,177)	(2,033,748)	(1,109,061,925)	(2,061,543)	(1,111,123,468)	(2,077,032)
Washington	WA	(279,786,928)	(881,127)	(280,668,055)	(884,369)	(281,552,424)	(888,709)	(282,441,133)	(893,819)	(283,334,953)	(899,902)	(284,234,855)	(924,081)	(285,158,936)	(947,067)
Eastern Wyoming	WYP	(296,816,024)	(1,042,547)	(297,858,572)	(1,045,621)	(298,904,193)	(1,049,125)	(299,953,318)	(1,053,572)	(301,006,890)	(1,058,341)	(302,065,232)	(1,062,515)	(303,127,746)	(1,066,878)
Utah	UT	(1,106,214,167)	(5,061,959)	(1,111,276,126)	(5,101,136)	(1,116,377,262)	(5,141,676)	(1,121,518,938)	(5,194,580)	(1,126,713,518)	(5,251,606)	(1,131,965,124)	(5,290,147)	(1,137,255,271)	(5,324,068)
Idaho	ID	(163,316,844)	(644,030)	(163,960,874)	(648,820)	(164,609,694)	(653,919)	(165,263,613)	(659,394)	(165,923,006)	(664,786)	(166,587,792)	(669,074)	(167,256,866)	(673,393)
Western Wyoming	WYU	(64,380,075)	(318,244)	(64,698,319)	(318,182)	(65,016,501)	(318,120)	(65,334,621)	(318,058)	(65,652,679)	(317,996)	(65,970,674)	(317,934)	(66,288,608)	(317,871)
Total Distribution Plant		(3,163,675,333)	(10,361,267)	(3,174,036,600)	(10,431,780)	(3,184,468,380)	(10,508,626)	(3,194,977,006)	(10,615,011)	(3,205,592,016)	(10,745,842)	(3,216,337,858)	(10,857,944)	(3,227,195,802)	(10,945,371)
General Plant:															
California	CA	(7,569,249)	(44,615)	(7,613,863)	(44,626)	(7,658,489)	(44,629)	(7,703,118)	(44,600)	(7,747,718)	(44,626)	(7,792,344)	(44,720)	(7,837,064)	(45,053)
Oregon	OR	(102,305,135)	(545,450)	(102,850,585)	(545,609)	(103,396,194)	(546,379)	(103,942,573)	(547,575)	(104,490,148)	(549,505)	(105,039,653)	(551,567)	(105,591,220)	(552,873)
Washington	WA	(25,388,959)	(59,146)	(25,448,105)	(59,070)	(25,507,175)	(59,048)	(25,566,223)	(59,043)	(25,625,267)	(59,156)	(25,684,423)	(59,326)	(25,743,748)	(59,382)
Eastern Wyoming	WYP	(27,992,775)	(101,119)	(28,093,894)	(101,111)	(28,195,005)	(101,330)	(28,296,335)	(101,859)	(28,398,194)	(102,686)	(28,500,879)	(103,285)	(28,604,164)	(103,919)
Utah	UT	(96,191,407)	(513,370)	(96,704,776)	(515,898)	(97,220,675)	(518,926)	(97,739,601)	(522,930)	(98,262,531)	(528,049)	(98,790,580)	(532,933)	(99,323,513)	(536,289)
Idaho	ID	(20,909,204)	(139,217)	(21,048,421)	(139,300)	(21,187,721)	(139,395)	(21,327,116)	(139,522)	(21,466,638)	(139,727)	(21,606,365)	(139,921)	(21,746,286)	(140,115)
Western Wyoming	WYU	(7,000,031)	(37,259)	(7,037,289)	(37,201)	(7,074,490)	(37,143)	(7,111,634)	(37,086)	(7,148,719)	(37,028)	(7,185,747)	(36,970)	(7,222,718)	(36,913)
Pre-merger Pacific	SG	(641,923)	10,571	(631,352)	10,595	(620,757)	10,620	(610,137)	10,644	(599,493)	10,668	(588,825)	10,693	(578,132)	10,717
Pre-merger Utah	SG	(1,805,174)	21,060	(1,784,114)	21,092	(1,763,022)	21,123	(1,741,899)	21,155	(1,720,744)	21,186	(1,699,557)	21,218	(1,678,339)	21,250
Post-merger	SG	(132,022,017)	(665,333)	(132,687,351)	(664,490)	(133,351,841)	(663,772)	(134,015,613)	(663,053)	(134,678,666)	(662,272)	(135,340,938)	(661,494)	(136,002,432)	(660,704)
General Office	SO	(119,452,945)	(525,055)	(119,978,000)	(523,527)	(120,501,527)	(522,391)	(121,023,918)	(525,278)	(121,549,196)	(535,100)	(122,084,296)	(543,112)	(122,627,408)	(543,564)
General Office	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-
General Office	SG	(137,255)	(978)	(138,233)	(978)	(139,212)	(978)	(140,190)	(978)	(141,169)	(978)	(142,147)	(978)	(143,126)	(978)
Customer Service	CN	(7,162,735)	17,326	(7,145,409)	17,819	(7,127,590)	18,312	(7,109,278)	18,806	(7,090,472)	19,299	(7,071,173)	19,792	(7,051,380)	20,286
Fuel Related	SE	(1,524,171)	2,187	(1,521,984)	2,232	(1,519,753)	2,277	(1,517,476)	2,322	(1,515,154)	2,367	(1,512,787)	2,412	(1,510,375)	2,457
Total General Plant		(550,102,979)	(2,580,398)	(552,683,377)	(2,580,072)	(555,263,450)	(2,581,659)	(557,845,109)	(2,588,999)	(560,434,108)	(2,605,607)	(563,039,715)	(2,620,191)	(565,659,905)	(2,625,081)
Mining Plant:															
Coal Mine	SE	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Mining Plant		-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Depreciation Reserve		(11,041,534,897)	(72,280,132)	(11,113,815,029)	(72,336,456)	(11,186,151,485)	(72,506,676)	(11,258,658,161)	(72,836,694)	(11,331,494,855)	(73,159,727)	(11,404,654,582)	(73,377,930)	(11,478,032,512)	(73,510,079)

PacifiCorp
Oregon General Rate Case - December 2023
Jun 2021 - December 2022 Depreciation & Amortization Reserve

Description	Factor	Adjusted Reserve Balance Jan 2022	Adjustments	Adjusted Reserve Balance Feb 2022	Adjustments	Adjusted Reserve Balance Mar 2022	Adjustments	Adjusted Reserve Balance Apr 2022	Adjustments	Adjusted Reserve Balance May 2022	Adjustments	Adjusted Reserve Balance Jun 2022	Adjustments	Adjusted Reserve Balance Jul 2022	Adjustments
AMORTIZATION RESERVE															
Intangible Plant:															
California	CA	(7,232)	(147)	(7,379)	(147)	(7,526)	(147)	(7,673)	(147)	(7,821)	(147)	(7,968)	(147)	(8,115)	(147)
Customer Service	CN	(170,464,466)	(1,117,092)	(171,581,558)	(1,116,908)	(172,698,467)	(1,116,724)	(173,815,191)	(1,116,540)	(174,931,731)	(1,116,356)	(176,048,087)	(1,116,172)	(177,164,260)	(1,115,988)
Idaho	ID	(989,775)	(1,834)	(991,609)	(1,834)	(993,442)	(1,834)	(995,276)	(1,833)	(997,109)	(1,833)	(998,943)	(1,833)	(1,000,776)	(1,833)
Pre-merger Utah	SG	(404,333)	(1,039)	(405,372)	(1,039)	(406,411)	(1,039)	(407,450)	(1,039)	(408,490)	(1,039)	(409,529)	(1,039)	(410,568)	(1,039)
Montana	MT	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Oregon	OR	(133,459)	(611)	(134,070)	(611)	(134,682)	(611)	(135,293)	(611)	(135,904)	(611)	(136,515)	(611)	(137,126)	(611)
Fuel Related	SE	27,262	4,438	31,699	4,506	36,205	4,574	40,778	4,642	45,420	4,710	50,129	4,777	54,907	4,845
Post-merger	SG	(109,713,867)	(533,046)	(110,246,914)	(532,868)	(110,779,782)	(532,689)	(111,312,471)	(532,511)	(111,844,982)	(532,333)	(112,377,315)	(532,154)	(112,909,469)	(531,976)
Hydro Relicensing	SG-P	(41,964,800)	(218,796)	(42,183,596)	(218,786)	(42,402,382)	(218,776)	(42,621,157)	(218,766)	(42,839,923)	(218,756)	(43,058,679)	(218,745)	(43,277,424)	(218,735)
Hydro Relicensing	SG-U	(5,838,397)	(11,696)	(5,850,094)	(11,656)	(5,861,750)	(11,616)	(5,873,366)	(11,576)	(5,884,942)	(11,536)	(5,896,477)	(11,496)	(5,907,973)	(11,456)
General Office	SO	(324,438,575)	(1,181,947)	(325,620,522)	(1,180,992)	(326,801,514)	(1,182,682)	(327,984,196)	(1,183,701)	(329,167,897)	(1,215,934)	(330,383,830)	(1,247,442)	(331,631,272)	(1,245,635)
Pre-merger Pacific	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Utah	UT	31,958,026	(2,671)	31,955,355	(2,671)	31,952,683	(2,672)	31,950,012	(2,672)	31,947,340	(2,672)	31,944,668	(2,672)	31,941,997	(2,672)
Washington	WA	(12,528)	(262)	(12,791)	(262)	(13,053)	(262)	(13,315)	(262)	(13,578)	(262)	(13,840)	(262)	(14,102)	(262)
Eastern Wyoming	WYP	(385,548)	(1,437)	(386,985)	(1,425)	(388,410)	(1,412)	(389,822)	(1,400)	(391,222)	(1,387)	(392,609)	(1,374)	(393,983)	(1,362)
Western Wyoming	WYU	-	-	-	-	-	-	-	-	-	-	-	-	-	-
General Office	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Klamath		(74,111,750)	-	(74,111,750)	-	(74,111,750)	-	(74,111,750)	-	(74,111,750)	-	(74,111,750)	-	(74,111,750)	-
Total Intangible Plant		(696,479,443)	(3,066,143)	(699,545,586)	(3,064,694)	(702,610,280)	(3,065,891)	(705,676,171)	(3,066,417)	(708,742,587)	(3,098,156)	(711,840,744)	(3,129,171)	(714,969,915)	(3,126,871)
Hydro Production Plant:															
Pre-merger Pacific	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG-P	(3,321,057)	(25,975)	(3,347,032)	(25,975)	(3,373,007)	(25,975)	(3,398,981)	(25,975)	(3,424,956)	(25,975)	(3,450,931)	(25,975)	(3,476,905)	(25,975)
Post-merger	SG-U	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Hydro Plant		(3,321,057)	(25,975)	(3,347,032)	(25,975)	(3,373,007)	(25,975)	(3,398,981)	(25,975)	(3,424,956)	(25,975)	(3,450,931)	(25,975)	(3,476,905)	(25,975)
Other Production Plant:															
Post-merger	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Other Plant		-	-	-	-	-	-	-	-	-	-	-	-	-	-
General Plant:															
California	CA	(505,860)	-	(505,860)	-	(505,860)	-	(505,860)	-	(505,860)	-	(505,860)	-	(505,860)	-
General Office	CN	-	-	-	-	-	-	-	-	-	-	-	-	-	-
General Office	ID	(333,771)	-	(333,771)	-	(333,771)	-	(333,771)	-	(333,771)	-	(333,771)	-	(333,771)	-
Oregon	OR	(4,929,366)	(26,909)	(4,956,275)	(26,909)	(4,983,183)	(26,909)	(5,010,092)	(26,909)	(5,037,001)	(26,909)	(5,063,909)	(26,909)	(5,090,818)	(26,909)
General Office	SO	(1,238,027)	(9,024)	(1,247,051)	(9,024)	(1,256,076)	(9,024)	(1,265,100)	(9,024)	(1,274,124)	(9,024)	(1,283,149)	(9,024)	(1,292,173)	(9,024)
Utah	UT	(33,127)	-	(33,127)	-	(33,127)	-	(33,127)	-	(33,127)	-	(33,127)	-	(33,127)	-
Washington	WA	(1,911,639)	(8,022)	(1,919,661)	(8,022)	(1,927,683)	(8,022)	(1,935,706)	(8,022)	(1,943,728)	(8,022)	(1,951,750)	(8,022)	(1,959,773)	(8,022)
Eastern Wyoming	WYP	(4,485,493)	(4,431)	(4,489,924)	(4,431)	(4,494,355)	(4,431)	(4,498,785)	(4,431)	(4,503,216)	(4,431)	(4,507,647)	(4,431)	(4,512,078)	(4,431)
Western Wyoming	WYU	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total General Plant		(13,437,282)	(48,386)	(13,485,668)	(48,386)	(13,534,054)	(48,386)	(13,582,440)	(48,386)	(13,630,826)	(48,386)	(13,679,213)	(48,386)	(13,727,599)	(48,386)
Total Amortization Reserve		(713,237,782)	(3,140,504)	(716,378,286)	(3,139,055)	(719,517,340)	(3,140,252)	(722,657,592)	(3,140,777)	(725,798,370)	(3,172,517)	(728,970,887)	(3,203,532)	(732,174,419)	(3,201,232)
Total Depreciation & Amortization Reserve		(11,754,772,678)	(75,420,636)	(11,830,193,314)	(75,475,511)	(11,905,668,825)	(75,646,928)	(11,981,315,754)	(75,977,471)	(12,057,293,225)	(76,332,244)	(12,133,625,468)	(76,581,462)	(12,210,206,931)	(76,711,311)

PacifiCorp
Oregon General Rate Case - December 2023
Jun 2021 - December 2022 Depreciation & Amortization Reserve

Description	Factor	Adjusted Reserve Balance Aug 2022	Adjustments	Adjusted Reserve Balance Sep 2022	Adjustments	Adjusted Reserve Balance Oct 2022	Adjustments	Adjusted Reserve Balance Nov 2022	Adjustments	Adjusted Reserve Balance Dec 2022	CY 2022 YE Balance	Incremental Reserve For Annualized Depreciation	CY 2022 Adjusted Reserve Year End Balance
DEPRECIATION RESERVE													
Steam Production Plant:													
Pre-merger Pacific	SG	(822,279,367)	(5,201,163)	(827,480,531)	(5,198,866)	(832,679,396)	(5,196,568)	(837,875,965)	(5,194,271)	(843,070,236)	(843,070,236)	165,417	(842,904,819)
Pre-merger Utah	SG	(774,091,717)	(3,855,334)	(777,947,051)	(3,853,083)	(781,800,134)	(3,850,832)	(785,650,966)	(3,848,582)	(789,499,548)	(789,499,548)	162,053	(789,337,495)
Post-merger	SG	(3,124,834,698)	(23,889,756)	(3,148,724,454)	(23,883,911)	(3,172,608,364)	(23,900,401)	(3,196,508,765)	(23,951,446)	(3,220,460,211)	(3,220,460,211)	(2,572,049)	(3,223,032,260)
Geothermal - Blundell	SG	(12,638,717)	(171,319)	(12,810,036)	(171,319)	(12,981,355)	(171,319)	(13,152,674)	(171,319)	(13,323,992)	(13,323,992)	-	(13,323,992)
Carbon	SG	-	-	-	-	-	-	-	-	-	-		-
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-	-		-
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-	-		-
Post-merger	SG	-	-	-	-	-	-	-	-	-	-		-
Total Steam Plant		(4,733,844,499)	(33,117,572)	(4,766,962,071)	(33,107,178)	(4,800,069,249)	(33,119,121)	(4,833,188,370)	(33,165,617)	(4,866,353,988)	(4,866,353,988)	(2,244,579)	(4,868,598,566)
Hydro Production Plant:													
Pre-merger Pacific	SG	(144,873,933)	(287,127)	(145,161,060)	(287,034)	(145,448,094)	(286,942)	(145,735,036)	(286,850)	(146,021,886)	(146,021,886)	6,647	(146,015,239)
Pre-merger Utah	SG	(32,507,271)	(71,557)	(32,578,828)	(71,470)	(32,650,298)	(71,383)	(32,721,681)	(71,296)	(32,792,977)	(32,792,977)	6,274	(32,786,703)
Post-merger	SG-P	(184,461,190)	(1,215,818)	(185,677,008)	(1,217,644)	(186,894,652)	(1,225,096)	(188,119,748)	(1,262,600)	(189,382,348)	(189,382,348)	(1,179,319)	(190,561,667)
Post-merger	SG-U	(69,972,201)	(556,872)	(70,529,073)	(563,314)	(71,092,386)	(569,851)	(71,662,237)	(604,083)	(72,266,320)	(72,266,320)	(930,311)	(73,196,630)
Klamath - New Capital	SG-P	(1,197,843)	(69,519)	(1,267,362)	(69,519)	(1,336,880)	(98,634)	(1,435,514)	(144,272)	(1,579,786)	(1,579,786)	(991,438)	(2,571,224)
Klamath		(93,431,009)	-	(93,431,009)	-	(93,431,009)	-	(93,431,009)	-	(93,431,009)	(93,431,009)	-	(93,431,009)
Total Hydro Plant		(526,443,447)	(2,200,893)	(528,644,340)	(2,208,981)	(530,853,321)	(2,251,905)	(533,105,226)	(2,369,100)	(535,474,326)	(535,474,326)	(3,088,147)	(538,562,473)
Other Production Plant:													
Pre-merger Utah	SG	-	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG	(532,143,233)	(3,564,770)	(535,708,003)	(3,562,872)	(539,270,875)	(3,560,974)	(542,831,849)	(3,564,991)	(546,396,841)	(546,396,841)	(181,484)	(546,578,324)
Post-merger Wind	SG-W	229,012,324	(11,098,382)	217,913,942	(11,101,909)	206,812,033	(11,105,437)	195,706,596	(11,108,965)	184,597,631	184,597,631	(254,869)	184,342,762
Black Cap Solar	OR	-	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG	(48,219,780)	(314,367)	(48,534,147)	(314,198)	(48,848,345)	(314,028)	(49,162,374)	(313,985)	(49,476,359)	(49,476,359)	8,813	(49,467,546)
Total Other Plant		(351,350,689)	(14,977,519)	(366,328,208)	(14,978,979)	(381,307,187)	(14,980,440)	(396,287,627)	(14,987,941)	(411,275,568)	(411,275,568)	(427,540)	(411,703,108)
Transmission Plant:													
Pre-merger Pacific	SG	(360,294,844)	(508,044)	(360,802,888)	(507,806)	(361,310,694)	(507,567)	(361,818,261)	(507,329)	(362,325,591)	(362,325,591)	17,154	(362,308,437)
Pre-merger Utah	SG	(434,725,277)	(563,852)	(435,289,129)	(563,440)	(435,852,568)	(563,028)	(436,415,596)	(562,616)	(436,978,212)	(436,978,212)	29,658	(436,948,554)
Post-merger	SG	(1,338,457,675)	(8,575,801)	(1,347,033,476)	(8,609,387)	(1,355,642,863)	(8,661,031)	(1,364,303,894)	(8,722,871)	(1,373,026,765)	(1,373,026,765)	(2,934,717)	(1,375,961,482)
Total Transmission Plant		(2,133,477,796)	(9,647,697)	(2,143,125,493)	(9,680,633)	(2,152,806,125)	(9,731,626)	(2,162,537,751)	(9,792,816)	(2,172,330,568)	(2,172,330,568)	(2,887,905)	(2,175,218,473)
Distribution Plant:													
California	CA	(157,523,968)	(540,820)	(158,064,789)	(544,048)	(158,608,837)	(548,233)	(159,157,070)	(557,571)	(159,714,641)	(159,714,641)	(530,085)	(160,244,726)
Oregon	OR	(1,113,200,500)	(2,092,049)	(1,115,292,550)	(2,107,002)	(1,117,399,552)	(2,116,584)	(1,119,516,136)	(2,136,253)	(1,121,652,389)	(1,121,652,389)	(1,458,257)	(1,123,110,646)
Washington	WA	(286,106,003)	(949,960)	(287,055,963)	(952,475)	(288,008,438)	(955,077)	(288,963,515)	(961,266)	(289,924,781)	(289,924,781)	(577,636)	(290,502,417)
Eastern Wyoming	WYP	(304,194,624)	(1,071,359)	(305,265,983)	(1,075,406)	(306,341,389)	(1,079,060)	(307,420,450)	(1,083,085)	(308,503,534)	(308,503,534)	(297,144)	(308,800,678)
Utah	UT	(1,142,579,339)	(5,355,355)	(1,147,934,694)	(5,393,821)	(1,153,328,515)	(5,443,978)	(1,158,772,493)	(5,491,767)	(1,164,264,259)	(1,164,264,259)	(3,067,247)	(1,167,331,507)
Idaho	ID	(167,930,260)	(678,493)	(168,608,753)	(683,641)	(169,292,394)	(687,773)	(169,980,167)	(694,094)	(170,674,261)	(170,674,261)	(384,997)	(171,059,258)
Western Wyoming	WYU	(66,606,479)	(317,809)	(66,924,289)	(317,747)	(67,242,036)	(317,685)	(67,559,721)	(317,623)	(67,877,344)	(67,877,344)	4,471	(67,872,874)
Total Distribution Plant		(3,238,141,173)	(11,005,847)	(3,249,147,020)	(11,074,141)	(3,260,221,161)	(11,148,391)	(3,271,369,552)	(11,241,658)	(3,282,611,210)	(3,282,611,210)	(6,310,896)	(3,288,922,105)
General Plant:													
California	CA	(7,882,117)	(45,403)	(7,927,520)	(45,537)	(7,973,057)	(45,632)	(8,018,689)	(45,949)	(8,064,637)	(8,064,637)	(14,724)	(8,079,361)
Oregon	OR	(106,144,092)	(554,186)	(106,698,279)	(555,757)	(107,254,036)	(557,732)	(107,811,767)	(562,789)	(108,374,556)	(108,374,556)	(184,474)	(108,559,029)
Washington	WA	(25,803,130)	(59,629)	(25,862,759)	(59,898)	(25,922,657)	(59,881)	(25,982,539)	(60,188)	(26,042,727)	(26,042,727)	(13,232)	(26,055,958)
Eastern Wyoming	WYP	(28,708,082)	(104,649)	(28,812,731)	(105,164)	(28,917,895)	(106,395)	(29,024,290)	(108,540)	(29,132,830)	(29,132,830)	(76,372)	(29,209,202)
Utah	UT	(99,859,802)	(539,219)	(100,399,022)	(542,643)	(100,941,665)	(545,840)	(101,487,505)	(550,992)	(102,038,498)	(102,038,498)	(298,463)	(102,336,961)
Idaho	ID	(21,886,401)	(140,321)	(22,026,722)	(140,527)	(22,167,249)	(140,832)	(22,308,081)	(141,488)	(22,449,570)	(22,449,570)	(24,154)	(22,473,724)
Western Wyoming	WYU	(7,259,630)	(36,855)	(7,296,485)	(36,797)	(7,333,283)	(36,740)	(7,370,022)	(36,682)	(7,406,704)	(7,406,704)	4,151	(7,402,553)
Pre-merger Pacific	SG	(567,415)	10,741	(556,674)	10,765	(545,909)	10,790	(535,119)	10,814	(524,305)	(524,305)	1,748	(522,557)
Pre-merger Utah	SG	(1,657,090)	21,281	(1,635,809)	21,313	(1,614,496)	21,344	(1,593,152)	21,376	(1,571,776)	(1,571,776)	2,273	(1,569,503)
Post-merger	SG	(136,663,136)	(660,399)	(137,323,535)	(660,807)	(137,984,341)	(663,044)	(138,647,385)	(672,999)	(139,320,385)	(139,320,385)	(207,710)	(139,528,094)
General Office	SO	(123,170,973)	(544,664)	(123,715,636)	(554,245)	(124,269,881)	(562,880)	(124,832,761)	(579,727)	(125,412,488)	(125,412,488)	(667,282)	(126,079,770)
General Office	SG	-	-	-	-	-	-	-	-	-	-	-	-
General Office	SG	(144,104)	(978)	(145,082)	(978)	(146,061)	(978)	(147,039)	(978)	(148,018)	(148,018)	-	(148,018)
Customer Service	CN	(7,031,095)	20,779	(7,010,316)	21,272	(6,989,044)	21,765	(6,967,279)	22,259	(6,945,020)	(6,945,020)	35,514	(6,909,506)
Fuel Related	SE	(1,507,918)	2,502	(1,505,415)	2,547	(1,502,868)	2,592	(1,500,275)	2,638	(1,497,638)	(1,497,638)	3,247	(1,494,391)
Total General Plant		(568,284,986)	(2,631,000)	(570,915,986)	(2,646,457)	(573,562,443)	(2,663,462)	(576,225,905)	(2,703,246)	(578,929,151)	(578,929,151)	(1,439,477)	(580,368,628)
Mining Plant:													
Coal Mine	SE	-	-	-	-	-	-	-	-	-	-	-	-
Total Mining Plant		-	-	-	-	-	-	-	-	-	-	-	-
Total Depreciation Reserve		(11,551,542,591)	(73,580,526)	(11,625,123,117)	(73,696,369)	(11,698,819,486)	(73,894,945)	(11,772,714,431)	(74,260,379)	(11,846,974,810)	(11,846,974,810)	(16,398,543)	(11,863,373,353)

PacifiCorp
Oregon General Rate Case - December 2023
Jun 2021 - December 2022 Depreciation & Amortization Reserve

Description	Factor	Adjusted Reserve Balance Aug 2022	Adjustments	Adjusted Reserve Balance Sep 2022	Adjustments	Adjusted Reserve Balance Oct 2022	Adjustments	Adjusted Reserve Balance Nov 2022	Adjustments	Adjusted Reserve Balance Dec 2022	CY 2022 YE Balance	Incremental Reserve For Annualized Depreciation	CY 2022 Adjusted Reserve Year End Balance
AMORTIZATION RESERVE													
Intangible Plant:													
California	CA	(8,262)	(147)	(8,409)	(147)	(8,556)	(147)	(8,703)	(147)	(8,850)	(8,850)	-	(8,850)
Customer Service	CN	(178,280,248)	(1,115,804)	(179,396,053)	(1,115,620)	(180,511,673)	(1,115,437)	(181,627,110)	(1,115,253)	(182,742,362)	(182,742,362)	13,245	(182,729,117)
Idaho	ID	(1,002,610)	(1,833)	(1,004,443)	(1,833)	(1,006,276)	(1,833)	(1,008,109)	(1,833)	(1,009,943)	(1,009,943)	(10,563)	(1,020,506)
Pre-merger Utah	SG	(411,607)	(1,039)	(412,646)	(1,039)	(413,686)	(1,039)	(414,725)	(1,039)	(415,764)	(415,764)	(12,470)	(428,234)
Montana	MT	-	-	-	-	-	-	-	-	-	-	-	-
Oregon	OR	(137,737)	(611)	(138,348)	(611)	(138,959)	(611)	(139,570)	(611)	(140,180)	(140,180)	6	(140,175)
Fuel Related	SE	59,752	4,913	64,666	4,981	69,647	5,049	74,697	5,117	79,814	79,814	4,895	84,709
Post-merger	SG	(113,441,445)	(531,797)	(113,973,242)	(531,619)	(114,504,861)	(531,441)	(115,036,302)	(531,262)	(115,567,564)	(115,567,564)	12,845	(115,554,719)
Hydro Relicensing	SG-P	(43,496,159)	(218,725)	(43,714,885)	(218,715)	(43,933,600)	(218,705)	(44,152,305)	(218,695)	(44,371,000)	(44,371,000)	726	(44,370,274)
Hydro Relicensing	SG-U	(5,919,429)	(11,415)	(5,930,844)	(11,375)	(5,942,219)	(11,335)	(5,953,555)	(11,295)	(5,964,850)	(5,964,850)	2,887	(5,961,962)
General Office	SO	(332,876,907)	(1,253,872)	(334,130,780)	(1,261,875)	(335,392,655)	(1,264,270)	(336,656,925)	(1,295,267)	(337,952,191)	(337,952,191)	(1,182,602)	(339,134,793)
Pre-merger Pacific	SG	-	-	-	-	-	-	-	-	-	-		-
Utah	UT	31,939,325	(2,672)	31,936,653	(2,672)	31,933,981	(2,672)	31,931,309	(2,672)	31,928,637	31,928,637	(5)	31,928,632
Washington	WA	(14,365)	(262)	(14,627)	(262)	(14,889)	(262)	(15,152)	(262)	(15,414)	(15,414)	-	(15,414)
Eastern Wyoming	WYP	(395,345)	(1,349)	(396,694)	(1,336)	(398,030)	(1,324)	(399,354)	(1,311)	(400,665)	(400,665)	909	(399,756)
Western Wyoming	WYU	-	-	-	-	-	-	-	-	-	-	-	-
General Office	SG	-	-	-	-	-	-	-	-	-	-		-
Klamath		(74,111,750)	-	(74,111,750)	-	(74,111,750)	-	(74,111,750)	-	(74,111,750)	(74,111,750)	-	(74,111,750)
Total Intangible Plant		(718,096,786)	(3,134,615)	(721,231,401)	(3,142,125)	(724,373,526)	(3,144,026)	(727,517,553)	(3,174,530)	(730,692,083)	(730,692,083)	(1,170,127)	(731,862,209)
Hydro Production Plant:													
Pre-merger Pacific	SG	-	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG-P	(3,502,880)	(25,975)	(3,528,855)	(25,975)	(3,554,829)	(25,975)	(3,580,804)	(25,975)	(3,606,778)	(3,606,778)	-	(3,606,778)
Post-merger	SG-U	-	-	-	-	-	-	-	-	-	-	-	-
Total Hydro Plant		(3,502,880)	(25,975)	(3,528,855)	(25,975)	(3,554,829)	(25,975)	(3,580,804)	(25,975)	(3,606,778)	(3,606,778)	-	(3,606,778)
Other Production Plant:													
Post-merger	SG	-	-	-	-	-	-	-	-	-	-	-	-
Total Other Plant		-	-	-	-	-	-	-	-	-	-	-	-
General Plant:													
California	CA	(505,860)	-	(505,860)	-	(505,860)	-	(505,860)	-	(505,860)	(505,860)	-	(505,860)
General Office	CN	-	-	-	-	-	-	-	-	-	-	-	-
General Office	ID	(333,771)	-	(333,771)	-	(333,771)	-	(333,771)	-	(333,771)	(333,771)		(333,771)
Oregon	OR	(5,117,727)	(26,909)	(5,144,636)	(26,909)	(5,171,544)	(26,909)	(5,198,453)	(26,909)	(5,225,362)	(5,225,362)	-	(5,225,362)
General Office	SO	(1,301,197)	(9,024)	(1,310,222)	(9,024)	(1,319,246)	(9,024)	(1,328,270)	(9,024)	(1,337,295)	(1,337,295)	-	(1,337,295)
Utah	UT	(33,127)	-	(33,127)	-	(33,127)	-	(33,127)	-	(33,127)	(33,127)	-	(33,127)
Washington	WA	(1,967,795)	(8,022)	(1,975,818)	(8,022)	(1,983,840)	(8,022)	(1,991,862)	(8,022)	(1,999,885)	(1,999,885)	-	(1,999,885)
Eastern Wyoming	WYP	(4,516,508)	(4,431)	(4,520,939)	(4,431)	(4,525,370)	(4,431)	(4,529,801)	(4,431)	(4,534,231)	(4,534,231)	-	(4,534,231)
Western Wyoming	WYU	-	-	-	-	-	-	-	-	-	-	-	-
Total General Plant		(13,775,985)	(48,386)	(13,824,371)	(48,386)	(13,872,757)	(48,386)	(13,921,143)	(48,386)	(13,969,530)	(13,969,530)	-	(13,969,530)
Total Amortization Reserve		(735,375,651)	(3,208,976)	(738,584,627)	(3,216,485)	(741,801,112)	(3,218,387)	(745,019,500)	(3,248,891)	(748,268,391)	(748,268,391)	(1,170,127)	(749,438,517)
Total Depreciation & Amortization Reserve		(12,286,918,242)	(76,789,502)	(12,363,707,744)	(76,912,854)	(12,440,620,598)	(77,113,332)	(12,517,733,930)	(77,509,270)	(12,595,243,201)	(12,595,243,201)	(17,568,670)	(12,612,811,871)

Ref. 6.2.3

PacifiCorp
Oregon Results of Operations - December 2023
Oregon Coal-Fired Steam Plant Depreciation

Depreciation Reserve Adjustment

	Total Company	Factor
Adjustment to June 2021 Reserve:		
Steam Plant Accumulated Depreciation	(903,108,676)	SG
Steam Plant Accumulated Depreciation	-	SG
	(903,108,676)	

Depreciation Reserve Adjustment By Plant

Plant	Factor	Adjustment to Expense (Yr Ended Jun 2021)
CHOLLA	SG	-
NAUGHTON	SG	(30,064,073)
HUNTINGTON	SG	(89,320,910)
HUNTER	SG	(195,988,110)
CRAIG	SG	(23,396,883)
HAYDEN	SG	(20,602,217)
COLSTRIP	SG	(15,343,966)
DAVE JOHNSTON	SG	(150,994,556)
JIM BRIDGER	SG	(281,627,624)
WYODAK	SG	(95,770,338)
		(903,108,676)

This is the increase in the depreciation reserve June 2021 starting balance in adjustment 6.2. This reflects the increase from January 2008 to June 2021 to reflect the different depreciation rates Oregon is using for the coal-fired generating plants. This was approved in the Depreciation Study, in Docket UM-1329 Order 08-427, with rates effective January 1, 2008.

PacifiCorp
Oregon General Rate Case - December 2023
Hydro Decommissioning
Spending, Accruals, and Balances - East Side, West Side, and Total Resources

West Side	Spend	Accruals	Balance
June-20	-	(173,152)	(7,919,677)
July-20	2,044	(173,152)	(8,090,786)
August-20	-	(173,152)	(8,263,937)
September-20	-	(173,152)	(8,437,089)
October-20	-	(173,152)	(8,610,241)
November-20	-	(173,152)	(8,783,393)
December-20	-	(173,152)	(8,956,544)
January-21	-	60,700	(8,895,845)
February-21	-	60,700	(8,835,145)
March-21	-	60,700	(8,774,445)
April-21	-	60,700	(8,713,746)
May-21	419,290	60,700	(8,233,755)
June-21	1,206,269	60,700	(6,966,787)

East Side	Spend	Accruals	Balance
June-20	-	25,600	(302,944)
July-20	-	25,600	(277,344)
August-20	-	25,600	(251,744)
September-20	-	25,600	(226,143)
October-20	-	25,600	(200,543)
November-20	-	25,600	(174,943)
December-20	-	25,600	(149,342)
January-21	-	(23,356)	(172,698)
February-21	-	(23,356)	(196,054)
March-21	-	(23,356)	(219,410)
April-21	-	(23,356)	(242,766)
May-21	-	(23,356)	(266,122)
June-21	-	(23,356)	(289,478)

Total Resources	Spend	Accruals	Balance
June-20	-	(147,551)	(8,222,622)
July-20	2,044	(147,551)	(8,368,130)
August-20	-	(147,551)	(8,515,681)
September-20	-	(147,551)	(8,663,232)
October-20	-	(147,551)	(8,810,784)
November-20	-	(147,551)	(8,958,335)
December-20	-	(147,551)	(9,105,887)
January-21	-	37,344	(9,068,543)
February-21	-	37,344	(9,031,199)
March-21	-	37,344	(8,993,855)
April-21	-	37,344	(8,956,512)
May-21	419,290	37,344	(8,499,878)
June-21	1,206,269	37,344	(7,256,265)

West Side	Spend	Accruals	Balance
July-21	-	60,700	(6,906,087)
August-21	-	60,700	(6,845,387)
September-21	-	60,700	(6,784,687)
October-21	-	60,700	(6,723,988)
November-21	-	60,700	(6,663,288)
December-21	-	60,700	(6,602,588)
January-22	-	60,700	(6,541,889)
February-22	-	60,700	(6,481,189)
March-22	-	60,700	(6,420,489)
April-22	-	60,700	(6,359,790)
May-22	-	60,700	(6,299,090)
June-22	-	60,700	(6,238,390)
July-22	-	60,700	(6,177,690)
August-22	-	60,700	(6,116,991)
September-22	-	60,700	(6,056,291)
October-22	-	60,700	(5,995,591)
November-22	-	60,700	(5,934,892)
December-22	-	60,700	(5,874,192)

East Side	Spend	Accruals	Balance
July-21	-	(23,356)	(312,834)
August-21	-	(23,356)	(336,190)
September-21	-	(23,356)	(359,546)
October-21	-	(23,356)	(382,902)
November-21	-	(23,356)	(406,258)
December-21	-	(23,356)	(429,614)
January-22	-	(23,356)	(452,970)
February-22	-	(23,356)	(476,326)
March-22	-	(23,356)	(499,682)
April-22	-	(23,356)	(523,038)
May-22	-	(23,356)	(546,394)
June-22	-	(23,356)	(569,750)
July-22	-	(23,356)	(593,106)
August-22	-	(23,356)	(616,462)
September-22	-	(23,356)	(639,818)
October-22	-	(23,356)	(663,174)
November-22	-	(23,356)	(686,529)
December-22	-	(23,356)	(709,885)

Total Resources	Spend	Accruals	Balance
July-21	-	37,344	(7,218,921)
August-21	-	37,344	(7,181,577)
September-21	-	37,344	(7,144,233)
October-21	-	37,344	(7,106,890)
November-21	-	37,344	(7,069,546)
December-21	-	37,344	(7,032,202)
January-22	-	37,344	(6,994,858)
February-22	-	37,344	(6,957,515)
March-22	-	37,344	(6,920,171)
April-22	-	37,344	(6,882,827)
May-22	-	37,344	(6,845,484)
June-22	-	37,344	(6,808,140)
July-22	-	37,344	(6,770,796)
August-22	-	37,344	(6,733,452)
September-22	-	37,344	(6,696,109)
October-22	-	37,344	(6,658,765)
November-22	-	37,344	(6,621,421)
December-22	-	37,344	(6,584,077)

West Side	Spend	Accruals	Balance
January-23	-	60,700	(5,813,492)
February-23	-	60,700	(5,752,793)
March-23	-	60,700	(5,692,093)
April-23	-	60,700	(5,631,393)
May-23	-	60,700	(5,570,693)
June-23	-	60,700	(5,509,994)
July-23	-	60,700	(5,449,294)
August-23	-	60,700	(5,388,594)
September-23	-	60,700	(5,327,895)
October-23	-	60,700	(5,267,195)
November-23	-	60,700	(5,206,495)
December-23	-	60,700	(5,145,796)

East Side	Spend	Accruals	Balance
January-23	-	(23,356)	(733,241)
February-23	-	(23,356)	(756,597)
March-23	-	(23,356)	(779,953)
April-23	-	(23,356)	(803,309)
May-23	-	(23,356)	(826,665)
June-23	-	(23,356)	(850,021)
July-23	-	(23,356)	(873,377)
August-23	-	(23,356)	(896,733)
September-23	-	(23,356)	(920,089)
October-23	-	(23,356)	(943,445)
November-23	-	(23,356)	(966,801)
December-23	-	(23,356)	(990,157)

Total Resources	Spend	Accruals	Balance
January-23	-	37,344	(6,546,734)
February-23	-	37,344	(6,509,390)
March-23	-	37,344	(6,472,046)
April-23	-	37,344	(6,434,702)
May-23	-	37,344	(6,397,359)
June-23	-	37,344	(6,360,015)
July-23	-	37,344	(6,322,671)
August-23	-	37,344	(6,285,327)
September-23	-	37,344	(6,247,984)
October-23	-	37,344	(6,210,640)
November-23	-	37,344	(6,173,296)
December-23	-	37,344	(6,135,952)

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	26.070%	(84,946)	6.3.1
Remove system allocated give-back reversal	403SP	1	(1,081,784)	SG	26.070%	(282,025)	6.3.2
			(1,407,617)			(366,971)	

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.

PacifiCorp PAGE 6.3.1
Oregon General Rate Case - December 2023
Depreciation Allocation Correction

	Account	Amount	Factor	
Actual	403SP	**325,833**	SG	**Ref. 6.3**

Calendar Year	Period	Account Number	Amount	Description	FERC Account	FERC Location	Actual Allocation
2020	7	565131	10,670	Amortize Deferred Depr Exp - Steam - UT	4032000	1	SG
2020	7	565131	36,849	Amortize Deferred Depr Exp - Steam - WY	4032000	1	SG
2020	7	565131	(170,211)	Defer Deprec Expense - Steam - ID	4032000	1	SG
2020	7	565131	(432)	Cholla Plant FERC Adj-Accum Depr	4032000	1	SG
2020	7	565131	184,935	ID - ECAM Def Depr Amort - FY2020	4032000	1	SG
2020	8	565131	10,670	Amortize Deferred Depr Exp - Steam - UT	4032000	1	SG
2020	8	565131	36,849	Amortize Deferred Depr Exp - Steam - WY	4032000	1	SG
2020	8	565131	(169,827)	Defer Deprec Expense - Steam - ID	4032000	1	SG
2020	8	565131	(432)	Cholla Plant FERC Adj-Accum Depr	4032000	1	SG
2020	8	565131	182,833	ID - ECAM Def Depr Amort - FY2020	4032000	1	SG
2020	9	565131	10,670	Amortize Deferred Depr Exp - Steam - UT	4032000	1	SG
2020	9	565131	36,849	Amortize Deferred Depr Exp - Steam - WY	4032000	1	SG
2020	9	565131	(171,927)	Defer Deprec Expense - Steam - ID	4032000	1	SG
2020	9	565131	(432)	Cholla Plant FERC Adj-Accum Depr	4032000	1	SG
2020	9	565131	178,731	ID - ECAM Def Depr Amort - FY2020	4032000	1	SG
2020	10	565131	10,670	Amortize Deferred Depr Exp - Steam - UT	4032000	1	SG
2020	10	565131	36,849	Amortize Deferred Depr Exp - Steam - WY	4032000	1	SG
2020	10	565131	(172,193)	Defer Deprec Expense - Steam - ID	4032000	1	SG
2020	10	565131	(432)	Cholla Plant FERC Adj-Accum Depr	4032000	1	SG
2020	10	565131	175,280	ID - ECAM Def Depr Amort - FY2020	4032000	1	SG
2020	11	565131	10,670	Amortize Deferred Depr Exp - Steam - UT	4032000	1	SG
2020	11	565131	36,849	Amortize Deferred Depr Exp - Steam - WY	4032000	1	SG
2020	11	565131	(171,907)	Defer Deprec Expense - Steam - ID	4032000	1	SG
2020	11	565131	(432)	Cholla Plant FERC Adj-Accum Depr	4032000	1	SG
2020	11	565131	182,085	ID - ECAM Def Depr Amort - FY2020	4032000	1	SG
2020	12	565131	10,670	Amortize Deferred Depr Exp - Steam - UT	4032000	1	SG
2020	12	565131	36,849	Amortize Deferred Depr Exp - Steam - WY	4032000	1	SG
2020	12	565131	(172,711)	Defer Deprec Expense - Steam - ID	4032000	1	SG
2020	12	565131	(432)	Cholla Plant FERC Adj-Accum Depr	4032000	1	SG
2020	12	565131	168,220	ID - ECAM Def Depr Amort - FY2021	4032000	1	SG
Total			325,833				

PacifiCorp
Oregon General Rate Case - December 2023
Depreciation Allocation Correction

	Account	Amount	Factor	
Actual	403SP	**1,081,784**	SG	**Ref. 6.3**

Calendar Year	Period	Account Number	Amount	Description	FERC Account	FERC Location	Actual Allocation
2020	7	565131	50,294	OR - Reverse give-back - Colstrip	4032000	108	SG
2020	7	565131	12,368	OR - Reverse give-back - Hunter Common	4032000	108	SG
2020	7	565131	37,736	OR - Reverse give-back - Hunter Unit 1	4032000	108	SG
2020	7	565131	24,881	OR - Reverse give-back - Hunter Unit 2	4032000	108	SG
2020	7	565131	52,486	OR - Reverse give-back - Hunter Unit 3	4032000	108	SG
2020	7	565131	2,533	OR - Reverse give-back - Hunter 1&2 Commor	4032000	108	SG
2020	8	565131	50,294	OR - Reverse give-back - Colstrip	4032000	108	SG
2020	8	565131	12,368	OR - Reverse give-back - Hunter Common	4032000	108	SG
2020	8	565131	37,736	OR - Reverse give-back - Hunter Unit 1	4032000	108	SG
2020	8	565131	24,881	OR - Reverse give-back - Hunter Unit 2	4032000	108	SG
2020	8	565131	52,486	OR - Reverse give-back - Hunter Unit 3	4032000	108	SG
2020	8	565131	2,533	OR - Reverse give-back - Hunter 1&2 Commor	4032000	108	SG
2020	9	565131	50,294	OR - Reverse give-back - Colstrip	4032000	108	SG
2020	9	565131	12,368	OR - Reverse give-back - Hunter Common	4032000	108	SG
2020	9	565131	37,736	OR - Reverse give-back - Hunter Unit 1	4032000	108	SG
2020	9	565131	24,881	OR - Reverse give-back - Hunter Unit 2	4032000	108	SG
2020	9	565131	52,486	OR - Reverse give-back - Hunter Unit 3	4032000	108	SG
2020	9	565131	2,533	OR - Reverse give-back - Hunter 1&2 Commor	4032000	108	SG
2020	10	565131	50,294	OR - Reverse give-back - Colstrip	4032000	108	SG
2020	10	565131	12,368	OR - Reverse give-back - Hunter Common	4032000	108	SG
2020	10	565131	37,736	OR - Reverse give-back - Hunter Unit 1	4032000	108	SG
2020	10	565131	24,881	OR - Reverse give-back - Hunter Unit 2	4032000	108	SG
2020	10	565131	52,486	OR - Reverse give-back - Hunter Unit 3	4032000	108	SG
2020	10	565131	2,533	OR - Reverse give-back - Hunter 1&2 Commor	4032000	108	SG
2020	11	565131	50,294	OR - Reverse give-back - Colstrip	4032000	108	SG
2020	11	565131	12,368	OR - Reverse give-back - Hunter Common	4032000	108	SG
2020	11	565131	37,736	OR - Reverse give-back - Hunter Unit 1	4032000	108	SG
2020	11	565131	24,881	OR - Reverse give-back - Hunter Unit 2	4032000	108	SG
2020	11	565131	52,486	OR - Reverse give-back - Hunter Unit 3	4032000	108	SG
2020	11	565131	2,533	OR - Reverse give-back - Hunter 1&2 Commor	4032000	108	SG
2020	12	565131	50,294	OR - Reverse give-back - Colstrip	4032000	108	SG
2020	12	565131	12,368	OR - Reverse give-back - Hunter Common	4032000	108	SG
2020	12	565131	37,736	OR - Reverse give-back - Hunter Unit 1	4032000	108	SG
2020	12	565131	24,881	OR - Reverse give-back - Hunter Unit 2	4032000	108	SG
2020	12	565131	52,486	OR - Reverse give-back - Hunter Unit 3	4032000	108	SG
2020	12	565131	2,533	OR - Reverse give-back - Hunter 1&2 Commor	4032000	108	SG
Total			1,081,784				

PacifiCorp
Oregon General Rate Case - December 2023
Repowering Buy Downs

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Dunlap Buy-down	407	1	26,889,854	OR	Situs	26,889,854	6.4.1
Foote Creek Buy-Down	407	1	2,631,642	OR	Situs	2,631,642	6.4.1
			29,521,495				
Repowered Facilities Buy-down	407	1	(3,359,575)	OR	Situs	(3,359,575)	6.4.2
Repowered Facilities Buy-down	407	3	(3,388,979)	OR	Situs	(3,388,979)	6.4.3
			(6,748,553)				
Adjustment to Reserves:							
RAC buy-down reserves adj.	108OP	1	(193,318,297)	OR	Situs	(193,318,297)	6.4.1
Repowered Facilities Reserve	108OP	3	10,122,830	OR	Situs	10,122,830	6.4.3
Adjustment to Tax							
Schedule M Adjustment	SCHMAT	3	(3,388,979)	OR	Situs	(3,388,979)	
Deferred Income Tax Expense	41110	3	833,235	OR	Situs	833,235	
Accumulated Def Inc Tax Balance	282	3	(2,488,860)	OR	Situs	(2,488,860)	

Description of Adjustment:

As a result of the all-party stipulation in docket UE 369, the undepreciated equipment balances from repowered assets were bought down in part with Excess Deferred Income Tax (EDIT) balances that resulted from the Tax and Job Cuts Act (TCJA), and a portion of the Company’s deferred FERC Open Access Transmission Tariff (OATT) revenues.

This adjustment corrects the allocation of expenses recorded as a result of the buy-down in the base period for the Dunlap, and Foote Creek wind facilities, as well as bring into rate base the accumulated reserves adjustment for wind facilities buy-downs for all repowered projects. Also reflected in this adjustment is the on-going amortization of this buy-down reserve balance to appropriately reflect these balances at Test Year levels. As the underlying wind assets depreciates, these buy-down reserves also need to be amortized in the opposite direction to offset Oregon's share of depreciation expense recorded for the repowered projects.

PacifiCorp
Oregon General Rate Case - December 2023
Repowering Buy-Downs

Year	Account	Actual FERC Account	Revised FERC Account	Text	Booked Alloc.	Correct Alloc.	Amount	
2020	565243	4034000	4070000	Oregon Portion of NBV - Dunlap	NUTIL	OR	26,889,854	**Ref 6.4**
2021	565243	4034000	4070000	Oregon Portion of NBV - Foote Creek	NUTIL	OR	2,631,642	**Ref 6.4**

Year	Account	Actual FERC Account	Revised FERC Account	Text	Booked Alloc.	Correct Alloc.	June 2021 EOP	
2021	145243	1085000	N/A	Production Plant - OR Buy-down Adj.	NUTIL	OR	(193,318,297)	**Ref 6.4**

PacifiCorp
Oregon General Rate Case - December 2023
Repowering Buy-Downs
Base Period Amortization

Amortization Expense	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	
Depr Adj - Dunlap OR Wind Buydown	(74,694)	(74,694)	(74,694)	(74,694)	(74,694)	(74,694)	
Depr Adj - Foote Creek OR Wind Buydown	-	-	(7,351)	(7,351)	(7,351)	(7,351)	
Depr Adj - Glenrock 1 OR Wind Buydown	(56,639)	(56,639)	(56,639)	(56,639)	(56,639)	(56,639)	
Depr Adj - Glenrock 3 OR Wind Buydown	(20,500)	(20,500)	(20,500)	(20,500)	(20,500)	(20,500)	
Depr Adj - Goodnoe Hills OR Wind Buydown	(66,309)	(66,309)	(66,309)	(66,309)	(66,309)	(66,309)	
Depr Adj - High Plains OR Wind Buydown	(74,042)	(74,042)	(74,042)	(74,042)	(74,042)	(74,042)	
Depr Adj - Leaning Juniper OR Wind Buydown	(48,430)	(48,430)	(48,430)	(48,430)	(48,430)	(48,430)	
Depr Adj - Marengo 1 OR Wind Buydown	(75,094)	(75,094)	(75,094)	(75,094)	(75,094)	(75,094)	
Depr Adj - Marengo 2 OR Wind Buydown	(39,822)	(39,822)	(39,822)	(39,822)	(39,822)	(39,822)	
Depr Adj - McFadden Ridge OR Wind Buydown	(18,898)	(18,898)	(18,898)	(18,898)	(18,898)	(18,898)	
Depr Adj - Seven Mile Hill 1 OR Wind Buydown	(66,713)	(66,713)	(66,713)	(66,713)	(66,713)	(66,713)	
Depr Adj - Seven Mile Hill 2 OR Wind Buydown	(13,888)	(13,888)	(13,888)	(13,888)	(13,888)	(13,888)	
Total	(555,028)	(555,028)	(562,379)	(562,379)	(562,379)	(562,379)	
					12 ME June 2021	**(3,359,575)**	**Ref 6.4.3**

Accumulated Amortization	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21
Dunlap OR Wind Buydown	74,694	149,388	224,082	298,776	373,470	448,164
Foote Creek OR Wind Buydown	-	-	7,351	14,702	22,053	29,404
Glenrock 1 OR Wind Buydown	56,639	113,278	169,917	226,556	283,195	339,833
Glenrock 3 OR Wind Buydown	20,500	40,999	61,499	81,999	102,499	122,998
Goodnoe Hills OR Wind Buydown	66,309	132,617	198,926	265,235	331,543	397,852
High Plains OR Wind Buydown	74,042	148,084	222,126	296,168	370,210	444,252
Leaning Juniper OR Wind Buydown	48,430	96,860	145,290	193,721	242,151	290,581
Marengo 1 OR Wind Buydown	75,094	150,189	225,283	300,378	375,472	450,567
Marengo 2 OR Wind Buydown	39,822	79,644	119,466	159,288	199,110	238,932
McFadden Ridge OR Wind Buydown	18,898	37,796	56,693	75,591	94,489	113,387
Seven Mile Hill 1 OR Wind Buydown	66,713	133,426	200,139	266,852	333,564	400,277
Seven Mile Hill 2 OR Wind Buydown	13,888	27,776	41,664	55,552	69,440	83,328
Total	555,028	1,110,057	1,672,436	2,234,816	2,797,195	**3,359,575**

PacifiCorp
Oregon General Rate Case - December 2023
Repowering Buy-Downs
Accumulated Amortization of Buy-down Balance

	Beginning Balance	Amortization Expense	Ending Balance	
6/30/2021			3,359,575	**Ref 6.4.2**
7/31/2021	3,359,575	(562,379)	3,921,954	
8/31/2021	3,921,954	(562,379)	4,484,334	
9/30/2021	4,484,334	(562,379)	5,046,713	
10/31/2021	5,046,713	(562,379)	5,609,092	
11/30/2021	5,609,092	(562,379)	6,171,472	
12/31/2021	6,171,472	(562,379)	6,733,851	
1/31/2022	6,733,851	(562,379)	7,296,231	
2/28/2022	7,296,231	(562,379)	7,858,610	
3/31/2022	7,858,610	(562,379)	8,420,990	
4/30/2022	8,420,990	(562,379)	8,983,369	
5/31/2022	8,983,369	(562,379)	9,545,748	
6/30/2022	9,545,748	(562,379)	10,108,128	
7/31/2022	10,108,128	(562,379)	10,670,507	
8/31/2022	10,670,507	(562,379)	11,232,887	
9/30/2022	11,232,887	(562,379)	11,795,266	
10/31/2022	11,795,266	(562,379)	12,357,646	
11/30/2022	12,357,646	(562,379)	12,920,025	
12/31/2022	12,920,025	(562,379)	13,482,404	*Below*
	Annual Amortization	(6,748,553)		
		Below		

Base Period Amortization Expense	(3,359,575)	Ref 6.4.2
Pro Forma Amortiztaion Expense	(6,748,553)	Above
Adjustment to Expense	**(3,388,979)**	**Ref 6.4**

Base Period Accum. Amort.	3,359,575	Above
Pro Forma Accum. Amort.	13,482,404	Above
Adjustment to Accum.	**10,122,830**	**Ref 6.4**

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	26.070%	(810,523)	6.5.1
Adjustment to Rate Base:							
Depreciation Reserve	108SP	3	1,554,492	SG	26.070%	405,261	6.5.1
Adjustment to Tax							
Schedule M Adjustment	SCHMAT	3	3,108,984	SG	26.070%	810,523	
Deferred Income Tax Expense	41110	3	(764,394)	SG	26.070%	(199,280)	
Accumulated Def Inc Tax Balance	282	3	382,197	SG	26.070%	99,640	

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.

PacifiCorp
Oregon General Rate Case - December 2023
Coal Depreciable Life Update
Change in Depreciation Expense

	PROPOSED END OF DEPRECIABLE LIFE	AS OF DEC 31, 2022 ORIGINAL COST	AS OF DEC 31, 2022 ACCUM. RESERVES	AS OF DEC 31, 2022 FUTURE ACCURALS	ACCEL. DEPR. RATES ANNUAL AMOUNT	ACCEL. DEPR. RATES ACCRUAL RATE	COMPOSITE REMAINING LIFE	EXISTING RATES CURRENT RATE[1]	EXISTING RATES CURRENT ACCRUAL	CHANGE
COLSTRIP GENERATING STATION	12-2025	245,683,766	190,060,942	71,638,975	25,796,827	10.50	2.8	5.71	13,996,713	11,800,114
CRAIG UNIT 2	09-2028	108,124,258	77,817,819	32,395,594	5,692,211	5.27	5.7	7.98	8,660,238	(2,968,027)
CRAIG COMMON	09-2028	52,548,072	45,115,710	8,291,679	1,449,040	2.76	5.7	5.69	2,975,274	(1,526,234)
HAYDEN UNIT 1	12-2028	55,376,031	50,125,428	5,804,363	969,756	1.75	6.0	11.67	6,455,275	(5,485,519)
HAYDEN UNIT 2	12-2027	32,275,692	29,254,112	3,344,337	668,232	2.07	5.0	11.85	3,833,821	(3,165,589)
HAYDEN COMMON	12-2028	28,208,413	26,025,830	2,316,267	385,285	1.37	6.0	7.63	2,149,014	(1,763,729)
		522,216,232	**418,399,841**	**123,791,214**	**34,961,351**				**38,070,335**	**(3,108,984)**
										Ref. 6.5
									Incremental Reserve Impact	**1,554,492**
										Ref. 6.5

Note 1 - Current rates are per approved 2018 Depreciation Study.

PacifiCorp
Oregon General Rate Case - December 2023
Coal Depreciable Life Update
Summary of Change in Depreciable Life

	End of Depreciable Life		Change		
	Current	2021 IRP			
COLSTRIP	2027	2025	2	years	Acceleration
CRAIG - UNIT 2 & COMMON	2026	Sep-28	1.8	years	Extension
HAYDEN UNIT 1	2023	2028	5	years	Extension
HAYDEN UNIT 2	2023	2027	4	years	Extension

PacifiCorp
Oregon General Rate Case - December 2023
Bridger Mine Reclamation Costs

Note: Please see Confidential Exhibit PAC/1007 for redacted information.

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Bridger Reclamation Costs	501	3	[redacted]	SE	25.068%	[redacted]	6.6.1
Adjustment to Rate Base							
Bridger Reclamation Costs	254	3	[redacted]	OR	Situs	[redacted]	6.6.1
Adjustment to Tax:							
Schedule M Adjustment	SCHMAT	3	[redacted]	SE	25.068%	[redacted]	6.6.1
Deferred Income Tax Expense	41110	3		SE	25.068%		6.6.1
Accumulated Def Inc Tax Balance	190	3		OR	Situs		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.

PacifiCorp
Oregon General Rate Case - December 2023
Bridger Final Reclamation Costs

PAGE 6.6.1 - REDACTED

Note: Please see Confidential Exhibit PAC/1007 for redacted information.

Annual Incremental Contribution for Reclamation	[redacted]	**Ref 6.6**
Incremental Depreciation Expense Prior to Reclamation	[redacted]	
Amortization Period (Years)	5	
Annual Incremental Depreciation Expense	[redacted]	**Ref 6.6**

	TOTAL COMPANY				
	501 **Mthly Accum.**	**SCHMAT** **Tax**	**41110** **DIT Exp**	**254** **Reg. Liab.**	**190** **ADIT**
Dec-20	-			-	-
Jan-21	[redacted]				
Feb-21					
Mar-21					
Apr-21					
May-21					
Jun-21					
Jul-21					
Aug-21					
Sep-21					
Oct-21					
Nov-21					
Dec-21					
Jan-22					
Feb-22					
Mar-22					
Apr-22					
May-22					
Jun-22					
Jul-22					
Aug-22					
Sep-22					
Oct-22					
Nov-22					
Dec-22					
Jan-23					
Feb-23					
Mar-23					
Apr-23					
May-23					
Jun-23					
Jul-23					
Aug-23					
Sep-23					
Oct-23					
Nov-23					
Dec-23					
Annual Total	[redacted]				
		Ref 6.6	**Ref 6.6**		
13 Mo. Avg. - Total Company				[redacted]	
13 Mo. Avg. - Oregon Allocated EOP June 2021 Balanace				[redacted]	
Adjustment					
				Ref 6.6	**Ref 6.6**

*Oregon 2023 SE Factor 25.068%

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 Interest True-Up
7.2 Property Tax Expense
7.3 Production Tax Credit
7.4 PowerTax ADIT Balance
7.5 Pro Forma Tax Balances
7.6 Wyoming Wind Generation Tax
7.7 AFUDC Equity
7.8 Tax Cuts and Jobs Act EDIT Adjustment
7.9 OCAT & Metro BIT

The tax impacts of the following adjustments are included within the adjustment itself:

- Insurance Expense, 4.5
- Repowering Buy-Downs, page 6.4
- Coal Depreciable Life Update, page 6.5
- Bridger Mine Reclamation Costs, page 6.6
- Trapper Mine Rate Base, page 8.2
- Jim Bridger Mine Rate Base, page 8.3
- Regulatory Assets & Liabilities Amortization, page 8.6
- Pension and Other Postretirement Plan Balances Removal, page 8.8
- Remove Rolling Hills, page 8.9
- Deer Creek Mine Closure, page 8.10
- Emissions Control Investment Adjustment, page 8.11
- Transmission Project Adjustment, page 8.12
- Cholla Unit 4 Retirement, page 8.13
- Wind Project Deferrals Amortization, page 8.14
- Carbon Plant Closure, page 8.16
- Labor Day Wildlife Restoration, page 8.17

The tax impacts of the following adjustment are included within adjustment 7.4 and 7.5:

- Pro Forma Plant Additions 8.4

Pacificorp
Oregon General Rate Case - December 2023
Tab 7 Adjustment Summary

		Total Adjustments	7.2 Property Tax Expense	7.3 Production Tax Credit	7.4 PowerTax ADIT	7.5 Pro Forma Tax Balances	7.6 Wyoming Wind Generation Tax	7.7 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	6,547,693	6,524,691	-	-	-	23,002	-
25	Income Taxes - Federal	(46,790,008)	(1,308,174)	(20,107,122)	(14,595,358)	(9,676,384)	(4,612)	218,647
26	Income Taxes - State	79,191	(296,265)	180	(3,305,445)	(2,193,137)	(1,044)	49,517
27	Income Taxes - Def Net	40,629,511	-	-	16,858,611	12,472,413	-	-
28	Investment Tax Credit Adj.	-	-	-	-	-	-	-
29	Misc Revenue & Expense	-	-	-	-	-	-	-
30								
31	Total Operating Expenses:	466,386	4,920,252	(20,106,941)	(1,042,192)	602,891	17,346	268,164
32								
33	Operating Rev For Return:	(466,386)	(4,920,252)	20,106,941	1,042,192	(602,891)	(17,346)	(268,164)
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	(379,622)	46,506	(190,051)	(169,198)	(112,191)	164	2,535
45	Weatherization Loans	-	-	-	-	-	-	-
46	Misc Rate Base	-	-	-	-	-	-	-
47								
48	Total Electric Plant:	(379,622)	46,506	(190,051)	(169,198)	(112,191)	164	2,535
49								
50	Rate Base Deductions:							
51	Accum Prov For Deprec	-	-	-	-	-	-	-
52	Accum Prov For Amort	-	-	-	-	-	-	-
53	Accum Def Income Tax	(50,169,049)	-	-	(42,192,733)	(1,694,247)	-	-
54	Unamortized ITC	4,573	-	-	-	4,573	-	-
55	Customer Adv For Const	-	-	-	-	-	-	-
56	Customer Service Deposits	-	-	-	-	-	-	-
57	Misc Rate Base Deductions	27,572,240	-	-	-	-	-	-
58								
59	Total Rate Base Deductions	(22,592,236)	-	-	(42,192,733)	(1,689,674)	-	-
60								
61	Total Rate Base:	(22,971,858)	46,506	(190,051)	(42,361,932)	(1,801,864)	164	2,535
62								
63	Return on Rate Base	0.013%	-0.122%	0.499%	0.077%	-0.013%	0.000%	-0.007%
64								
65	Return on Equity	0.026%	-0.234%	0.955%	0.147%	-0.025%	-0.001%	-0.013%
66								
67	TAX CALCULATION:							
68	Operating Revenue	(6,547,693)	(6,524,691)	-	-	-	(23,002)	-
69	Other Deductions	-	-	-	-	-	-	-
70	Interest (AFUDC)	(1,090,745)	-	-	-	-	-	(1,090,745)
71	Interest	(480,344)	972	(3,974)	(885,793)	(37,677)	3	53
72	Schedule "M" Additions	(93,710,028)	-	-	(74,319,275)	(19,390,753)	-	-
73	Schedule "M" Deductions	28,327,582	-	-	(626,331)	28,953,913	-	-
74	Income Before Tax	(127,014,213)	(6,525,663)	3,974	(72,807,151)	(48,306,989)	(23,005)	1,090,692
75								
76	State Income Taxes	79,191	(296,265)	180	(3,305,445)	(2,193,137)	(1,044)	49,517
77	Taxable Income	(127,093,404)	(6,229,398)	3,794	(69,501,706)	(46,113,852)	(21,961)	1,041,175
78								
79	Federal Income Taxes + Other	(46,790,008)	(1,308,174)	(20,107,122)	(14,595,358)	(9,676,384)	(4,612)	218,647
	APPROXIMATE PRICE CHANGE	(1,631,974)	6,750,067	(27,584,605)	(5,617,390)	648,379	23,796	367,893

Pacificorp
Oregon General Rate Case - December 2023
Tab 7 Adjustment Summary

		7.8 TCJA EDIT Adjustment	7.9 Oregon Corporate Activity Tax & Metro BIT
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	-	-
25	Income Taxes - Federal	(89,239)	(1,227,767)
26	Income Taxes - State	(20,210)	5,845,595
27	Income Taxes - Def Net	11,298,487	-
28	Investment Tax Credit Adj.	-	-
29	Misc Revenue & Expense	-	-
30			
31	Total Operating Expenses:	11,189,038	4,617,828
32			
33	Operating Rev For Return:	(11,189,038)	(4,617,828)
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	(1,035)	43,648
45	Weatherization Loans	-	-
46	Misc Rate Base	-	-
47			
48	Total Electric Plant:	(1,035)	43,648
49			
50	Rate Base Deductions:		
51	Accum Prov For Deprec	-	-
52	Accum Prov For Amort	-	-
53	Accum Def Income Tax	(6,282,069)	-
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	21,290,171	-
60			
61	Total Rate Base:	21,289,137	43,648
62			
63	Return on Rate Base	-0.305%	-0.115%
64			
65	Return on Equity	-0.583%	-0.220%
66			
67	TAX CALCULATION:		
68	Operating Revenue	-	-
69	Other Deductions	-	-
70	Interest (AFUDC)	-	-
71	Interest	445,158	913
72	Schedule "M" Additions	-	-
73	Schedule "M" Deductions	-	-
74	Income Before Tax	(445,158)	(913)
75			
76	State Income Taxes	(20,210)	5,845,595
77	Taxable Income	(424,948)	(5,846,507)
78			
79	Federal Income Taxes + Other	(89,239)	(1,227,767)
	APPROXIMATE PRICE CHANGE	17,444,713	6,335,173

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	(12,159,051)	OR	Situs	(12,159,051)	Below

Adjustment Detail:	**Total Company**		
Interest June 2021 - Unadjusted	373,768,734	99,963,159	2.15
Interest December 2023 - Normalized	337,754,203	87,804,109	Below
Adjustment:	(36,014,532)	(12,159,051)	

Normalized Rate Base	16,152,666,878	4,199,120,259	2.2
Other & Non-Regulated		-	
Adjusted Rate Base	16,152,666,878	4,199,120,259	2.2
Weighted Cost of Debt	2.091%	2.091%	2.1
Normalized Interest	337,754,203	87,804,109	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.

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	27.173%	6,524,691	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.

PacifiCorp
Oregon General Rate Case - December 2023
Property Tax Adjustment Summary - Oregon

FERC Account	G/L Account	Co. Code	Total	Ref
408.15	579000	1000	161,965,403	
Total Accrued Property Tax - 12 Months End. June 2021			161,965,403	
12 Months Ending December 31, 2023 Property Tax Estimate of $185,977,000			185,977,000	
Less: Property Tax Expense for 12 Months Ended 6/30/2021			(161,965,403)	
Incremental Adjustment to Property Taxes			**24,011,597**	**Ref 7.2**

PacifiCorp
Oregon General Rate Case - December 2023
Production Tax Credit

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Tax:							
Adj to Pro Forma PTC	40910	3	(77,129,477)	SG	26.070%	(20,107,918)	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 reflects into Test Period results the pro forma period Production Tax Credits (PTC) 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.

Pacific Power PAGE 7.3.1
Oregon General Rate Case - December 2023
Production Tax Credit

Pro Forma Period - December 2023					
Description	**Total Available KWh**	**PIS Date**	**Total PTC Eligible KWh**	**Factor (inflated tax per unit)**	**Federal Income Tax Credit**
Wind					
Glenrock KWh **[a]**	369,732,556	**9/24/2019**	339,044,754	0.027	9,154,208
Glenrock III KWh **[a]**	136,868,303	**11/24/2019**	113,600,691	0.027	3,067,219
Goodnoe KWh	283,697,016	**12/20/2019**	283,697,016	0.027	7,659,819
High Plains Wind	382,404,334	**12/19/2019**	382,404,334	0.027	10,324,917
Leaning Juniper 1 KWh	300,456,476	**9/13/2019**	300,456,476	0.027	8,112,325
Marengo KWh	494,513,357	**1/27/2020**	494,513,357	0.027	13,351,861
Marengo II KWh	246,897,019	**2/25/2020**	246,897,019	0.027	6,666,219
McFadden Ridge	116,545,267	**11/17/2019**	116,545,267	0.027	3,146,722
Rolling Hills KWh **[b]**	-	**10/17/2019**	-	-	-
Seven Mile KWh	417,048,284	**9/9/2019**	417,048,284	0.027	11,260,304
Seven Mile II KWh	87,428,374	**9/9/2019**	87,428,374	0.027	2,360,566
Dunlap I Wind KWh	476,748,520	**9/7/2020**	476,748,520	0.027	12,872,210
Foote Creek I Wind	176,189,324	**3/24/2021**	176,189,324	0.027	4,757,112
Pryor Mountain Wind	822,111,447	**VARIOUS**	822,111,447	0.027	22,197,009
Cedar Springs Wind II	749,501,065	**12/4/2020**	749,501,065	0.027	20,236,529
Ekola Flats Wind	819,429,669	**VARIOUS**	819,429,669	0.027	22,124,601
TB Flats Wind	837,974,852	**VARIOUS**	837,974,852	0.027	22,625,321
TB Flats Wind II	856,272,738	**VARIOUS**	856,272,738	0.027	23,119,364
Total KWh Production	7,573,818,600		7,519,863,187		203,036,306
	-		-		
Federal Production Tax Credit					203,036,306

June 2021 Base Period - PTC 125,906,829

Pro forma Adjustment 77,129,477

Repowering In Service dates in **bold** reflect actual in-service dates. **Ref. 7.3**

[a] Total available Kwh is reflected net of the generation that is not considered PTC eligible because the facility was not fully repowered. For Glenrock, the disallowed Kwh represents 8.3% of the total. For Glenrock III, the disallowed Kwh represents 17% disallowed.

[b] Oregon does not include Rolling Hills in rate base, therefore, there are no credits for Rolling Hills.

PacifiCorp
Oregon General Rate Case - December 2023
PowerTax ADIT

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Tax:							
Accelerated Pollution Control Facilities	281	3	148,004,159	SG	26.070%	38,585,190	
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)			(42,192,733)	7.4.1
Schedule M Adjustment	SCHMAP	3	(20,640)	SCHMDEXP	22.648%	(4,674)	7.4.1
Schedule M Adjustment	SCHMAT	3	311,609,727	SCHMDEXP	22.648%	70,572,481	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	27.173%	(1,475,951)	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	25.599%	(346,551)	7.4.1
Schedule M Adjustment	SCHMAT	3	(2,662,525)	SG	26.070%	(694,129)	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	27.173%	(2,121,444)	7.4.1
Schedule M Adjustment	SCHMDT	3	2,582,634	SG	26.070%	673,301	7.4.1
Schedule M Adjustment	SCHMDT	3	507,694	SNP	25.599%	129,962	7.4.1
Schedule M Adjustment	SCHMDT	3	(151,260,232)	GPS	27.173%	(41,102,067)	7.4.1
Deferred Income Tax Expense	41110	3	(76,614,237)	SCHMDEXP	22.648%	(17,351,374)	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	27.173%	362,886	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	25.599%	85,205	7.4.1
Deferred Income Tax Expense	41110	3	654,624	SG	26.070%	170,663	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	27.173%	(521,591)	7.4.1
Deferred Income Tax Expense	41010	3	634,982	SG	26.070%	165,542	7.4.1
Deferred Income Tax Expense	41010	3	124,825	SNP	25.599%	31,953	7.4.1
Deferred Income Tax Expense	41010	3	(37,189,748)	GPS	27.173%	(10,105,601)	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.

PacifiCorp
Oregon General Rate Case - December 2023
PowerTax Adjustment for Year Ended December 2022

Book Tax Difference		Total Company			STATE Allocation
Description - ADIT	**#**	**Base Period 6/30/2021 - Utility**	**Adjustment**	**Adjusted Utility**	**2020 Protocol**
Accelerated Pollution Control Facilities Depreciation	287960	(148,004,159)	148,004,159	0	SG
Accumulated Deferred Income Taxes - YE	287605	(2,745,860,351)	2,745,860,351	0	DITBAL
Accumulated Deferred Income Taxes (CA) - YE	**	0	(67,305,536)	(67,305,536)	CA
Accumulated Deferred Income Taxes (IDU) - YE	**	0	(181,930,228)	(181,930,228)	IDU
Accumulated Deferred Income Taxes (OR) - YE	**	0	(753,603,338)	(753,603,338)	OR
Accumulated Deferred Income Taxes (OTHER) - YE	**	0	(62,185,819)	(62,185,819)	OTHER
Accumulated Deferred Income Taxes (UT) - YE	**	0	(1,372,605,502)	(1,372,605,502)	UT
Accumulated Deferred Income Taxes (WA) - YE	**	0	(189,228,486)	(189,228,486)	WA
Accumulated Deferred Income Taxes (WY) - YE	**	0	(448,663,332)	(448,663,332)	WYP
Rounding	**	0	0	0	DITBAL
		(2,893,864,510)	**(181,657,732)**	**(3,075,522,242)**	
			Ref. 7.4		

Book Tax Difference		Total Company			STATE Allocation	
Description - Schedule M Items	**#**	**Base Period 6/30/2021 - Utility**	**Adjusted Utility**	**Adjustment**	**2020 Protocol**	
Schedule M Additions:						
Permanent Addition:						
Book Depreciation - M&E	105.127	149,749	129,109	(20,640)	SCHMDEXP	**Ref 7.4**
Timing Additions:						
Book Depreciation	105.120 & Other	859,859,922	1,171,469,649	311,609,727	SCHMDEXP	**Ref 7.4**
Book Depreciation - Utah Situs	105.120	225,430,833	-	(225,430,833)	UT	**Ref 7.4**
Book Depreciation - Oregon Situs	105.120	131,758,074	-	(131,758,074)	OR	**Ref 7.4**
Book Depreciation - Idaho		16,938,209	1	(16,938,208)	IDU	**Ref 7.4**
Book Depreciation - California Situs	105.120	-	-	-	CA	**Ref 7.4**
Book Depreciation - Washington Situs	105.120	-	-	-	WA	**Ref 7.4**
Capitalized Labor & Benefits Costs	105.100	4,075,367	(1,356,297)	(5,431,664)	SO	**Ref 7.4**
CIAC	105.130	121,888,015	85,613,628	(36,274,387)	CIAC	**Ref 7.4**
Reimbursements	105.140	3,813,773	-	(3,813,773)	SNPD	**Ref 7.4**
Avoided Costs	Basis Adj 105.142	72,599,478	71,245,689	(1,353,789)	SNP	**Ref 7.4**
Capitalization of Test Energy	105.146	2,662,525	-	(2,662,525)	SG	
Total Schedule M Adds		1,439,175,945	1,327,101,779	(112,074,166)		
Schedule M Deductions:						
Repair Deduction	105.122	154,034,912	156,617,546	2,582,634	SG	**Ref 7.4**
Tax Depreciation	105.125	1,225,252,918	1,383,505,094	158,252,176	TAXDEPR	**Ref 7.4**
Capitalized Depreciation	105.137	7,807,154	-	(7,807,154)	SO	**Ref 7.4**
AFUDC - Debt	105.141 - Debt	38,222,450	34,277,548	(3,944,902)	SNP	**Ref 7.4**
AFUDC - Equity	105.141 - Equity	78,974,277	83,426,873	4,452,596	SNP	**Ref 7.4**
Tax Gain / (Loss) on Prop. Disposition	105.152	119,531,346	2,625,086	(116,906,260)	GPS	**Ref 7.4**
Removal Costs	105.175	78,603,972	44,250,000	(34,353,972)	GPS	**Ref 7.4**
Total Schedule M Deducts		1,702,427,029	1,704,702,147	2,275,118		

Book Tax Difference		Total Company				STATE Allocation	
Description - Deferred Income Tax Expense	**#**	**Base Period 6/30/2021 - Utility**	**Adjusted Utility**	**Correction to BW**	**Adjustment**	**2020 Protocol**	
Flow-through:							
California	105.115	(327,913)	(254,674)	-	73,239	CA	
Idaho	105.115	(415,654)	68,796	-	484,450	IDU	
Oregon	105.115	(1,937,044)	(3,195,873)	-	(1,258,830)	OR	**Ref 7.4**
Washington	105.115	1,147,123	1,112,730	-	(34,393)	WA	
Wyoming - P	105.115	(1,137,075)	(1,571,894)	-	(434,819)	WYP	
Wyoming - U	105.115	(1,107,021)	(240,115)	-	866,906	WYU	
Utah	105.115	(4,820,168)	1,039,046	-	5,859,215	UT	
U FERC	105.115	(187,414)	(251,433)	-	(64,019)	FERC	
Other	105.115	(78,578)	24,523	-	103,101	OTHER	
Total		(8,863,744)	(3,268,893)	-	5,594,851		

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	25.068%	(2,647)	
	SCHMAP	3	(450,502)	SO	27.173%	(122,415)	
	SCHMDP	3	(5,308,942)	SE	25.068%	(1,330,853)	
	SCHMDP	3	(2,060)	SNP	25.599%	(527)	
Schedule M Adjustment Temporary	SCHMAT	3	(3,553,889)	BADDEBT	48.485%	(1,723,107)	
	SCHMAT	3	(186,149)	CA	Situs	-	
	SCHMAT	3	4,929,707	GPS	27.173%	1,339,553	
	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	25.068%	(5,027,835)	
	SCHMAT	3	(170,296)	SG	26.070%	(44,397)	
	SCHMAT	3	(582,468)	SNP	25.599%	(149,103)	
	SCHMAT	3	(15,602,237)	SO	27.173%	(4,239,609)	
	SCHMAT	3	45,715	TROJD	25.891%	11,836	
	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	25.068%	1,143,951	
	SCHMDT	3	(856,231)	SG	26.070%	(223,222)	
	SCHMDT	3	(969,539)	SNPD	26.473%	(256,662)	
	SCHMDT	3	110,880,326	SO	27.173%	30,129,602	
	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	25.068%	7,074	
	40910	3	1,659	SO	27.173%	451	
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.

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	25.068%	281,259	
	41010	3	(210,518)	SG	26.070%	(54,883)	
	41010	3	(238,377)	SNPD	26.473%	(63,105)	
	41010	3	27,261,704	SO	27.173%	7,407,845	
	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	48.485%	423,653	
	41110	3	45,768	CA	Situs	-	
	41110	3	63,250	ID	Situs	-	
	41110	3	-	FERC	0.000%	-	
	41110	3	(1,212,047)	GPS	27.173%	(329,351)	
	41110	3	2,319,262	OR	Situs	2,319,262	
	41110	3	(57,946,167)	OTHER	0.000%	-	
	41110	3	4,931,256	SE	25.068%	1,236,174	
	41110	3	1,152,362	SG	26.070%	300,425	
	41110	3	143,209	SNP	25.599%	36,659	
	41110	3	3,836,059	SO	27.173%	1,042,375	
	41110	3	(11,240)	TROJD	25.891%	(2,910)	
	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.

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	48.485%	139,170	
	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	25.068%	(236,521)	
	190	3	(577,551)	SG	26.070%	(150,570)	
	190	3	(16,485,532)	SO	27.173%	(4,479,627)	
	190	3	(9,977)	TROJD	25.891%	(2,583)	
	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	25.068%	(19,600)	
	282	3	(11,946)	SO	27.173%	(3,246)	
	282	3	77,911	SNP	25.599%	19,944	
	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	27.173%	(9,865)	
	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	25.068%	129,198	
	283	3	(269,601)	SG	26.070%	(70,286)	
	283	3	70,997	SNP	25.599%	18,174	
	283	3	9,428,836	SO	27.173%	2,562,105	
	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	26.070%	4,573	
	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.

PacifiCorp
Oregon General Rate Case - December 2023
Wyoming Wind Generation Tax

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Tax:							
Taxes Other Than Income	408	3	88,230	SG	26.070%	23,002	7.6.1

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 entity 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.

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)	108,649	12/1/2023	108,649	
TB Flats Wind (a)	111,117	12/1/2023	111,117	
TB Flats Wind II (a)	36,627	12/22/2023	36,627	
Total WY Wind MWH	2,320,579		2,320,579	
June 2021 Base Period			2,232,349	
ProForma Adjustment - December 2023			88,230	**Ref 7.6**

(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	25.599%	(1,090,745)	

Description of Adjustment:

This adjustment brings in the appropriate level of AFUDC - Equity into results to align the tax Schedule M with regulatory income.

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	25.068%	497,007	
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.

PacifiCorp
Oregon General Rate Case - December 2023
Oregon Corporate Activity Tax & Metro BIT

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Oregon Corporate Activity Tax	40911	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.

PacifiCorp
Oregon General Rate Case - December 2023
Oregon Corporate Activity Tax

			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 40911			5,601,037	**Ref. 7.9**

PacifiCorp
Oregon General Rate Case - December 2023
Oregon Corporate Activity Tax & Metro BIT

PAGE 7.9.2

			Metro Business Income Tax	
Jun-21	12 months	Metro Business Income Tax - Base Period	-	
Dec-23	12 months	Metro Business Income Tax - 2023 Forecast	244,599	
		Total	244,599	
Adjustment to Account 40911			244,599	**Ref. 7.9**

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 Cash Working Capital
8.2 Trapper Mine Rate Base
8.3 Jim Bridger Mine Rate Base
8.4 Pro Forma Plant Additions & Retirements
8.5 Customer Advances for Construction
8.6 Regulatory Assets & Liabilities Amortization
8.7 FERC 105 (PHFU) Adjustment
8.8 Pension and Other Post-retirement Balances Removal
8.9 Remove Rolling Hills
8.10 Deer Creek Mine Adjustment
8.11 Emissions Control Investment Adjustment
8.12 Transmission Project Adjustment
8.13 Cholla Unit 4 Retirement
8.14 Wind Project Deferrals Amortization
8.15 Miscellaneous Rate Base
8.16 Carbon Plant Closure
8.17 Labor Day Wildfire Restoration

Pacificorp
Oregon General Rate Case - December 2023
Tab 8 Adjustment Summary

		Total Adjustments	8.2 Trapper Mine Rate Base	8.3 Jim Bridger Mine Rate Base	8.4 Pro Forma Plant Additions and Retirements	8.5 Customer Advances for Construction	8.6 Regulatory Assets & Liabilities Amortization	8.7 FERC 105 (PHFU) Adjustment
1	Operating Revenues:							
2	General Business Revenues	-	-	-	-	-	-	-
3	Interdepartmental	-	-	-	-	-	-	-
4	Special Sales	-	-	-	-	-	-	-
5	Other Operating Revenues	2,235,548	-	-	-	-	2,235,548	-
6	Total Operating Revenues	2,235,548	-	-	-	-	2,235,548	-
7								
8	Operating Expenses:							
9	Steam Production	(13,042,384)	-	-	-	-	-	-
10	Nuclear Production	-	-	-	-	-	-	-
11	Hydro Production	-	-	-	-	-	-	-
12	Other Power Supply	(297,478)	-	-	-	-	-	-
13	Transmission	-	-	-	-	-	-	-
14	Distribution	-	-	-	-	-	-	-
15	Customer Accounting	-	-	-	-	-	-	-
16	Customer Service & Info	-	-	-	-	-	-	-
17	Sales	-	-	-	-	-	-	-
18	Administrative & General	(980,746)	-	-	-	-	-	-
19								
20	Total O&M Expenses	(14,320,608)	-	-	-	-	-	-
21								
22	Depreciation	(3,093,033)	-	-	-	-	-	-
23	Amortization	2,373,437	-	-	-	-	(3,080,765)	-
24	Taxes Other Than Income	-	-	-	-	-	-	-
25	Income Taxes - Federal	5,625,758	70,898	(42,235)	(788,947)	(21,333)	1,490,380	40,482
26	Income Taxes - State	1,274,079	16,056	(9,565)	(178,675)	(4,831)	337,530	9,168
27	Income Taxes - Def Net	(3,623,440)	(95,204)	-	(1,036,727)	-	(515,499)	-
28	Investment Tax Credit Adj.	-	-	-	-	-	-	-
29	Misc Revenue & Expense	-	-	-	-	-	-	-
30								
31	Total Operating Expenses:	(11,763,808)	(8,250)	(51,800)	(2,004,348)	(26,164)	(1,768,354)	49,650
32								
33	Operating Rev For Return:	13,999,357	8,250	51,800	2,004,348	26,164	4,003,902	(49,650)
34								
35	Rate Base:							
36	Electric Plant In Service	285,403,652	2,044,862	10,218,169	389,382,973	-	-	-
37	Plant Held for Future Use	(9,657,872)	-	-	-	-	-	(9,657,872)
38	Misc Deferred Debits	(126,476,526)	-	-	-	-	-	-
39	Elec Plant Acq Adj	(1,051,423)	-	-	-	-	(1,051,423)	-
40	Nuclear Fuel	(7,786,953)	-	-	-	-	-	-
41	Prepayments	-	-	-	-	-	-	-
42	Fuel Stock	(7,313,106)	-	-	-	-	-	-
43	Material & Supplies	(1,392,651)	-	-	-	-	-	-
44	Working Capital	(609,953)	(538,990)	(490)	(9,146)	(247)	17,277	469
45	Weatherization Loans	-	-	-	-	-	-	-
46	Misc Rate Base	-	-	-	-	-	-	-
47								
48	Total Electric Plant:	131,115,168	1,505,872	10,217,680	389,373,827	(247)	(1,034,146)	(9,657,402)
49								
50	Rate Base Deductions:							
51	Accum Prov For Deprec	(3,746,161)	-	-	-	-	-	-
52	Accum Prov For Amort	-	-	-	-	-	-	-
53	Accum Def Income Tax	40,243,899	98,774	(142,084)	494,791	-	-	-
54	Unamortized ITC	-	-	-	-	-	-	-
55	Customer Adv For Const	5,089,393	-	-	-	5,089,393	-	-
56	Customer Service Deposits	-	-	-	-	-	-	-
57	Misc Rate Base Deductions	16,186,182	-	-	-	-	-	-
58								
59	Total Rate Base Deductions	57,773,313	98,774	(142,084)	494,791	5,089,393	-	-
60								
61	Total Rate Base:	188,888,481	1,604,646	10,075,595	389,868,618	5,089,146	(1,034,146)	(9,657,402)
62								
63	Return on Rate Base	0.136%	-0.002%	-0.010%	-0.342%	-0.004%	0.092%	0.008%
64								
65	Return on Equity	0.260%	-0.003%	-0.019%	-0.654%	-0.008%	0.175%	0.015%
66								
67	TAX CALCULATION:							
68	Operating Revenue	17,275,753	-	-	-	-	5,316,314	-
69	Other Deductions	-	-	-	-	-	-	-
70	Interest (AFUDC)	-	-	-	-	-	-	-
71	Interest	3,949,681	33,553	210,682	8,152,200	106,415	(21,624)	(201,937)
72	Schedule "M" Additions	9,745,647	387,218	-	3,695,103	-	5,049,553	-
73	Schedule "M" Deductions	(4,991,685)	-	-	(521,533)	-	2,952,912	-
74	Income Before Tax	28,063,404	353,664	(210,682)	(3,935,563)	(106,415)	7,434,579	201,937
75								
76	State Income Taxes	1,274,079	16,056	(9,565)	(178,675)	(4,831)	337,530	9,168
77	Taxable Income	26,789,326	337,608	(201,117)	(3,756,888)	(101,583)	7,097,049	192,769
78								
79	Federal Income Taxes + Other	5,625,758	70,898	(42,235)	(788,947)	(21,333)	1,490,380	40,482
	APPROXIMATE PRICE CHANGE	(515,983)	147,351	925,222	35,800,847	467,326	(5,591,443)	(886,820)

Pacificorp
Oregon General Rate Case - December 202
Tab 8 Adjustment Summary

	8.8 Pension and Other Post-retirement Balances Removal	8.9 Remove Rolling Hills	8.10 Deer Creek Mine Adjustment	8.11 Emissions Control Investment Adjustment	8.12 Transmission Project Adjustment	8.13 Cholla Unit 4 Retirement	8.14 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	-	-	(9,223,534)	-	-	(3,818,850)	-
10 Nuclear Production	-	-	-	-	-	-	-
11 Hydro Production	-	-	-	-	-	-	-
12 Other Power Supply	-	(297,478)	-	-	-	-	-
13 Transmission	-	-	-	-	-	-	-
14 Distribution	-	-	-	-	-	-	-
15 Customer Accounting	-	-	-	-	-	-	-
16 Customer Service & Info	-	-	-	-	-	-	-
17 Sales	-	-	-	-	-	-	-
18 Administrative & General	-	(117,259)	806,229	(1,669,716)	-	-	-
19							
20 Total O&M Expenses	-	(414,737)	(8,417,305)	(1,669,716)	-	(3,818,850)	-
21							
22 Depreciation	-	-	-	(84,762)	-	-	-
23 Amortization	-	-	-	-	-	762,619	6,397,077
24 Taxes Other Than Income	-	-	-	-	-	-	-
25 Income Taxes - Federal	310,979	837,440	834,534	345,714	598	587,745	-
26 Income Taxes - State	70,428	189,657	188,999	78,295	135	133,108	-
27 Income Taxes - Def Net	-	(707,111)	1,100,367	12,584	-	38,516	(1,572,828)
28 Investment Tax Credit Adj.	-	-	-	-	-	-	-
29 Misc Revenue & Expense	-	-	-	-	-	-	-
30							
31 Total Operating Expenses:	381,407	(94,750)	(6,293,405)	(1,317,887)	734	(2,296,863)	4,824,249
32							
33 Operating Rev For Return:	(381,407)	94,750	6,293,405	1,317,887	(734)	2,296,863	(4,824,249)
34							
35 Rate Base:							
36 Electric Plant In Service	-	(50,873,419)	-	(1,212,256)	(182,000)	-	-
37 Plant Held for Future Use	-	-	-	-	-	-	-
38 Misc Deferred Debits	(110,544,888)	-	(11,013,202)	-	-	309,565	-
39 Elec Plant Acq Adj	-	-	-	-	-	-	-
40 Nuclear Fuel	(7,786,953)	-	-	-	-	-	-
41 Prepayments	-	-	-	-	-	-	-
42 Fuel Stock	-	-	-	-	-	-	-
43 Material & Supplies	-	-	-	-	-	(1,392,651)	-
44 Working Capital	3,605	5,788	(69,886)	(11,774)	7	(29,282)	-
45 Weatherization Loans	-	-	-	-	-	-	-
46 Misc Rate Base	-	-	-	-	-	-	-
47							
48 Total Electric Plant:	(118,328,235)	(50,867,631)	(11,083,088)	(1,224,030)	(181,993)	(1,112,368)	-
49							
50 Rate Base Deductions:							
51 Accum Prov For Deprec	-	(4,661,784)	-	84,762	28,512	-	-
52 Accum Prov For Amort	-	-	-	-	-	-	-
53 Accum Def Income Tax	23,914,636	13,118,713	507,306	122,816	10,751	(433,098)	-
54 Unamortized ITC	-	-	-	-	-	-	-
55 Customer Adv For Const	-	-	-	-	-	-	-
56 Customer Service Deposits	-	-	-	-	-	-	-
57 Misc Rate Base Deductions	20,225,559	-	-	-	-	-	-
58							
59 Total Rate Base Deductions	44,140,194	8,456,929	507,306	207,579	39,263	(433,098)	-
60							
61 Total Rate Base:	(74,188,041)	(42,410,702)	(10,575,782)	(1,016,451)	(142,730)	(1,545,466)	-
62							
63 Return on Rate Base	0.062%	0.044%	0.158%	0.032%	0.000%	0.055%	-0.113%
64							
65 Return on Equity	0.119%	0.084%	0.302%	0.061%	0.000%	0.106%	-0.216%
66							
67 TAX CALCULATION:							
68 Operating Revenue	-	414,737	8,417,305	1,754,479	-	3,056,231	(6,397,077)
69 Other Deductions	-	-	-	-	-	-	-
70 Interest (AFUDC)	-	-	-	-	-	-	-
71 Interest	(1,551,281)	(886,813)	(221,141)	(21,254)	(2,985)	(32,316)	-
72 Schedule "M" Additions	-	19	(5,541,906)	(84,763)	-	(156,655)	6,397,077
73 Schedule "M" Deductions	-	(2,875,900)	(1,066,432)	(33,581)	-	-	-
74 Income Before Tax	1,551,281	4,177,468	4,162,972	1,724,551	2,985	2,931,891	-
75							
76 State Income Taxes	70,428	189,657	188,999	78,295	135	133,108	-
77 Taxable Income	1,480,853	3,987,811	3,973,973	1,646,256	2,849	2,798,784	-
78							
79 Federal Income Taxes + Other	310,979	837,440	834,534	345,714	598	587,745	-
APPROXIMATE PRICE CHANGE	(6,812,538)	(4,323,307)	(9,673,700)	(1,907,273)	(13,107)	(3,301,717)	6,613,853

Pacificorp
Oregon General Rate Case - December 202
Tab 8 Adjustment Summary

		8.15	8.16	8.17
		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	-	(3,008,271)	-
23	Amortization	-	(1,705,494)	-
24	Taxes Other Than Income	-	-	-
25	Income Taxes - Federal	49,174	618,693	1,291,635
26	Income Taxes - State	11,137	140,117	292,520
27	Income Taxes - Def Net	-	419,323	(1,266,861)
28	Investment Tax Credit Adj.	-	-	-
29	Misc Revenue & Expense	-	-	-
30				
31	Total Operating Expenses:	60,311	(3,535,633)	317,293
32				
33	Operating Rev For Return:	(60,311)	3,535,633	(317,293)
34				
35	Rate Base:			
36	Electric Plant In Service	-	-	(63,974,678)
37	Plant Held for Future Use	-	-	-
38	Misc Deferred Debits	(4,418,666)	(809,336)	-
39	Elec Plant Acq Adj	-	-	-
40	Nuclear Fuel	-	-	-
41	Prepayments	-	-	-
42	Fuel Stock	(7,313,106)	-	-
43	Material & Supplies	-	-	-
44	Working Capital	570	7,172	14,973
45	Weatherization Loans	-	-	-
46	Misc Rate Base	-	-	-
47				
48	Total Electric Plant:	(11,731,202)	(802,164)	(63,959,704)
49				
50	Rate Base Deductions:			
51	Accum Prov For Deprec	-	-	802,349
52	Accum Prov For Amort	-	-	-
53	Accum Def Income Tax	-	1,111,185	1,440,110
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	-	(2,928,192)	2,242,459
60				
61	Total Rate Base:	(11,731,202)	(3,730,356)	(61,717,245)
62				
63	Return on Rate Base	0.011%	0.087%	0.058%
64				
65	Return on Equity	0.020%	0.166%	0.111%
66				
67	TAX CALCULATION:			
68	Operating Revenue	-	4,713,765	-
69	Other Deductions	-	-	-
70	Interest (AFUDC)	-	-	-
71	Interest	(245,301)	(78,002)	(1,290,515)
72	Schedule "M" Additions	-	-	-
73	Schedule "M" Deductions	-	1,705,494	(5,152,646)
74	Income Before Tax	245,301	3,086,273	6,443,161
75				
76	State Income Taxes	11,137	140,117	292,520
77	Taxable Income	234,164	2,946,156	6,150,641
78				
79	Federal Income Taxes + Other	49,174	618,693	1,291,635
	APPROXIMATE PRICE CHANGE	(1,077,253)	(5,216,054)	(5,667,370)

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	(107,814)	OR	Situs	(107,814)	Below
Adjustment Detail:							
Cash Working Capital June 2021 - Unadjusted			30,454,966			8,611,296	2.28
Cash Working Capital December 2023 - Normalized			29,774,416			8,503,482	2.28
Adjustment:			(680,550)			(107,814)	

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.

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	3,121,551,077	58,913,813	872,542,561	230,326,389	424,577,540	353,331,962	1,345,821,963	188,541,838	71,245,578	826,973
Taxes Other than Income	234,822,593	5,662,440	84,171,808	15,559,791	28,608,688	24,024,486	88,944,546	11,833,351	4,584,202	41,969
Federal Income Tax	(142,051,017)	(374,862)	(61,296,146)	(9,212,286)	(33,776,153)	(25,502,958)	(34,028,758)	(5,570,976)	(8,273,195)	2,208,163
State Income Tax	19,938,979	589,852	4,230,426	1,518,468	(1,122,384)	(367,390)	12,708,855	1,500,217	(754,994)	513,545
Total	3,234,261,632	64,791,242	899,648,649	238,192,363	418,287,692	351,486,101	1,413,446,606	196,304,430	66,801,591	3,590,650
Divided by Days in Year	365	365	365	365	365	365	365	365	365	365
Avg. Daily Cost of Service	8,860,991	177,510	2,464,791	652,582	1,145,994	962,976	3,872,456	537,820	183,018	9,837
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	**29,774,416**	163,168	**8,503,482**	3,961,172	1,018,899	856,178	15,754,630	367,858	162,721	5,206
	Ref. 8.1		**Ref. 8.1**							

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	25.068%	2,339,989	Below
Other Tangible Property	399	3	(1,177,299)	SE	25.068%	(295,127)	Below
			8,157,216			2,044,862	Below
Final Reclamation Liability	2533	3	(2,153,378)	SE	25.068%	(539,812)	Below
Adjustment to Tax:							
Schedule M Adj - Reclamation Liab	SCHMAT	3	1,544,661	SE	25.068%	387,218	8.2.2
Deferred Income Tax Expense	41110	3	(379,780)	SE	25.068%	(95,204)	8.2.2
Accumulated Def Inc Tax Balance	190	3	394,020	SE	25.068%	98,774	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.

PacifiCorp
Oregon General Rate Case - December 2023
Trapper Mine Rate Base

DESCRIPTION	Jun-21 Actual	Jan-22 Forecast	Feb-22 Forecast	Mar-22 Forecast	Apr-22 Forecast	May-22 Forecast	Jun-22 Forecast
Property, Plant, and Equipment							
Lands and Leases	17,748,984	17,748,984	17,748,984	17,748,984	17,748,984	17,748,984	17,748,984
Development Costs	2,834,815	2,834,815	2,834,815	2,834,815	2,834,815	2,834,815	2,834,815
Equipment and Facilities	126,096,849	127,016,467	127,445,821	127,445,821	127,524,353	126,060,805	126,096,849
Total Property, Plant, and Equipment	146,680,648	147,600,266	148,029,620	148,029,620	148,108,152	146,644,604	146,680,648
Accumulated Depreciation	(121,309,323)	(123,314,154)	(123,596,037)	(123,877,920)	(124,159,803)	(124,441,687)	(124,723,570)
Total Property, Plant, and Equipment	25,371,325	24,286,112	24,433,583	24,151,700	23,948,349	22,202,917	21,957,078
Other							
Inventories	5,855,454	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000
Prepaid Expenses	148,766	136,364	122,727	109,091	95,455	81,818	68,182
Restricted Funds: Self-bonding for Black Lung	657,793	657,793	657,793	657,793	657,793	657,793	657,793
Deferred GE Royalty Amount	-	-	-	-	-	-	-
Advance Royalty - State 206-13	-	-	-	-	-	-	-
Total Other	6,662,013	6,794,157	6,780,520	6,766,884	6,753,248	6,739,611	6,725,975
Total Rate Base	32,033,338	31,080,269	31,214,103	30,918,584	30,701,596	28,942,529	28,683,053
PacifiCorp Share (29.14%)	**9,334,515**	**9,056,790**	**9,095,790**	**9,009,675**	**8,946,445**	**8,433,853**	**8,358,242**

DESCRIPTION	Jul-22 Forecast	Aug-22 Forecast	Sep-22 Forecast	Oct-22 Forecast	Nov-22 Forecast	Dec-22 Forecast
Property, Plant, and Equipment						
Lands and Leases	17,748,984	17,748,984	17,748,984	17,748,984	17,748,984	17,748,984
Development Costs	2,834,815	2,834,815	2,834,815	2,834,815	2,834,815	2,834,815
Equipment and Facilities	126,126,654	126,156,672	127,016,467	127,016,467	127,016,467	127,016,467
Total Property, Plant, and Equipment	146,710,453	146,740,471	147,600,266	147,600,266	147,600,266	147,600,266
Accumulated Depreciation	(125,005,453)	(125,287,336)	(125,569,219)	(125,851,102)	(126,132,985)	(126,414,868)
Total Property, Plant, and Equipment	21,705,000	21,453,135	22,031,047	21,749,164	21,467,281	21,185,398
Other						
Inventories	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000
Prepaid Expenses	54,545	40,909	27,273	13,636	0	150,000
Restricted Funds: Self-bonding for Black Lung	657,793	657,793	657,793	657,793	657,793	657,793
Deferred GE Royalty Amount	-	-	-	-	-	-
Advance Royalty - State 206-13	-	-	-	-	-	-
Total Other	6,712,338	6,698,702	6,685,066	6,671,429	6,657,793	6,807,793
Total Rate Base	28,417,339	28,151,837	28,716,113	28,420,593	28,125,074	27,993,191
PacifiCorp Share (29.14%)	**8,280,812**	**8,203,445**	**8,367,875**	**8,281,761**	**8,195,646**	**8,157,216**

June 2021 End of Period Balance	**9,334,515**	**Ref 8.2**
December 2022 End of Period Balance	**8,157,216**	**Ref 8.2**

PacifiCorp
Oregon General Rate Case - December 2023
Trapper Mine
Final Reclamation Liability

Actuals

Description:	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21
Final Reclamation Liability	(6,874,217)	(6,886,120)	(6,904,116)	(6,922,709)	(6,939,870)	(6,961,463)	(7,139,466)	(7,199,003)	(7,334,523)	(7,420,190)	(7,550,403)	(7,672,867)

Forecast

Description:	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22
Final Reclamation Liability	(8,557,557)	(8,693,236)	(8,828,915)	(8,964,594)	(9,100,272)	(9,235,951)	(9,371,630)	(9,507,309)	(9,642,987)	(9,778,666)	(9,914,345)	(10,050,024)

End of Period Balance:

June 2021 12 Mth. Average	(7,150,412)	
December 2022 12 Mth. Average	(9,303,790)	
Adjustment to Rate Base	(2,153,378)	Ref 8.2

Adjustments for Tax:
Change in Liability Account Balance:

Schedule M Add - Pro Forma	**2,377,157**	
Schedule M Add - Base Period	832,496	
Adjustment needed	**1,544,661**	**Ref 8.2**
Def Inc Tax Exp - Pro Forma	**(584,462)**	
Def Inc Tax Exp - Base Period	(204,682)	
Adjustment needed	**(379,780)**	**Ref 8.2**

ADIT Adjustment for Tax:

Actuals Account 287216 (FERC Account 190) M#605.715

Description:	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21
Trapper Mine Contract Obligation	1,672,103	1,677,591	1,680,518	1,683,317	1,687,889	1,692,108	1,697,901	1,741,666	1,756,304	1,772,076	1,793,138	1,825,154	1,876,786

Forecast

Description:	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22
Trapper Mine Contract Obligation	2,070,654	2,104,012	2,137,371	2,170,730	2,204,089	2,237,448	2,270,806	2,304,165	2,337,524	2,370,883	2,404,242	2,437,600	2,470,959

End of Period Balance:

Base Period June 2021 End of Period	1,876,786	
December 2022 13 Mth. Average	2,270,806	
Adjustment to Rate Base	**394,020**	**Ref 8.2**

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	25.068%	17,661,352	Below
Other Tangible Property	399	3	(29,691,808)	SE	25.068%	(7,443,183)	Below
			40,761,585			10,218,169	
Adjustment to Tax:							
Accumulated Def Inc Tax Balance	190	3	(566,792)	SE	25.068%	(142,084)	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.

PacifiCorp
Oregon General Rate Case - December 2023
Bridger Mine Rate Base
End of Period
(000's)

Bridger Total	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual
Description	**Jun-20**	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**	**Jan-21**	**Feb-21**	**Mar-21**	**Apr-21**	**May-21**	**Jun-21**
1 Structure, Equipment, Mine Dev.	443,268	443,915	444,291	444,462	444,522	444,453	444,566	444,115	444,555	445,008	445,008	437,569	437,572
2 Materials & Supplies	14,681	14,271	13,913	13,670	13,464	13,151	13,081	12,668	12,101	12,189	11,687	11,085	10,760
4 Pit Inventory	40,522	39,386	35,477	29,754	29,033	27,057	27,609	24,940	27,571	33,051	37,777	39,455	36,350
5 Deferred Long Wall Costs	4,801	3,967	4,072	4,512	4,549	4,733	5,179	4,912	4,502	4,381	4,249	3,637	3,789
6 Reclamation Liability	-	-	-	-	-	-	-	-	-	-	-	-	-
7 Accumulated Depreciation	(364,463)	(366,892)	(369,293)	(371,032)	(373,040)	(375,179)	(377,270)	(379,094)	(381,388)	(383,865)	(386,036)	(380,979)	(382,790)
8 Bonus Bid / Lease Payable	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL RATE BASE	138,809	134,647	128,459	121,366	118,528	114,215	113,166	107,541	107,342	110,764	112,687	110,767	105,680
PacifiCorp Share (66.67%)	**92,539**	**89,765**	**85,639**	**80,911**	**79,018**	**76,143**	**75,444**	**71,694**	**71,561**	**73,842**	**75,124**	**73,845**	**70,453**

Bridger Total	Pro Forma	Pro Forma	Pro Forma	Pro Forma	Pro Forma	Pro Forma	Pro Forma	Pro Forma	Pro Forma	Pro Forma	Pro Forma	Pro Forma	Pro Forma
Description	**Dec-21**	**Jan-22**	**Feb-22**	**Mar-22**	**Apr-22**	**May-22**	**Jun-22**	**Jul-22**	**Aug-22**	**Sep-22**	**Oct-22**	**Nov-22**	**Dec-22**
1 Structure, Equipment, Mine Dev.	443,465	443,592	443,613	443,635	444,271	444,293	445,687	445,708	445,885	446,986	447,662	447,683	448,089
2 Materials & Supplies	13,998	9,860	9,844	9,827	9,810	9,794	9,566	9,549	9,533	9,516	9,499	9,483	9,466
4 Pit Inventory	27,860	27,067	22,768	21,686	23,580	23,898	24,673	23,393	20,794	18,845	17,930	15,321	8,579
5 Deferred Long Wall Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
6 Reclamation Liability	-	-	-	-	-	-	-	-	-	-	-	-	-
7 Accumulated Depreciation	(396,067)	(396,807)	(397,524)	(398,241)	(398,965)	(399,717)	(400,459)	(401,198)	(401,939)	(402,696)	(403,470)	(404,238)	(404,992)
8 Bonus Bid / Lease Payable	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL RATE BASE	89,256	83,713	78,701	76,908	78,697	78,268	79,467	77,453	74,272	72,650	71,621	68,248	61,142
PacifiCorp Share (66.67%)	**59,504**	**55,809**	**52,467**	**51,272**	**52,464**	**52,179**	**52,978**	**51,635**	**49,515**	**48,434**	**47,747**	**45,499**	**40,762**

June 2021 - End of Period Balance	**70,453**	**Ref 8.3**
December 2022 - End of Period Balance	**40,762**	**Ref 8.3**

PacifiCorp
Oregon General Rate Case - December 2023
Bridger Mine Rate Base
End of Period
(000's)

	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	12/1/2022
Materials & Supplies:													
Obsolete Reserve - Surface	(319,053)	(335,720)	(352,386)	(369,053)	(385,720)	(402,386)	(419,053)	(435,720)	(452,386)	(469,053)	(485,720)	(502,386)	(519,053)
Obsolete Reserve - Underground	(3,362,169)	(3,362,169)	(3,362,169)	(3,362,169)	(3,362,169)	(3,362,169)	-	-	-	-	-	-	-
Total Obsolete Reserves	(3,681,222)	(3,697,889)	(3,714,555)	(3,731,222)	(3,747,889)	(3,764,555)	(419,053)	(435,720)	(452,386)	(469,053)	(485,720)	(502,386)	(519,053)
PacifiCorp's 2/3 share:													
Obsolete Reserve - Surface	(212,702)	(223,813)	(234,924)	(246,035)	(257,146)	(268,258)	(279,369)	(290,480)	(301,591)	(312,702)	(323,813)	(334,924)	(346,035)
Obsolete Reserve - Underground	(2,241,446)	(2,241,446)	(2,241,446)	(2,241,446)	(2,241,446)	(2,241,446)	-	-	-	-	-	-	-
Total of PacifiCorp's share of Obsolete Reserves	(2,454,148)	(2,465,259)	(2,476,370)	(2,487,481)	(2,498,592)	(2,509,704)	(279,369)	(290,480)	(301,591)	(312,702)	(323,813)	(334,924)	**(346,035)**

ADIT 190 EOP Balance at June 30, 2021	**651,870**	**Per Tax Model (Account 287938, M#205.205)**
ADIT 190 EOP Balance at December 31, 2022	**85,078**	
Adjustment	**(566,792)**	**Ref 8.3**

PacifiCorp
Oregon General Rate Case - December 2023
Pro Forma Plant Additions and Retirements

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Steam Plant	312	3	(7,415,427)	SG	26.070%	(1,933,227)	
Steam Plant	312	3	(9,693,976)	SG	26.070%	(2,527,253)	
Steam Plant	312	3	83,311,329	SG	26.070%	21,719,548	
Steam Plant	312	3	-	SG	26.070%	-	
Hydro Plant	332	3	(29,867,468)	SG-P	26.070%	(7,786,551)	
Hydro Plant	332	3	(591,603)	SG-U	26.070%	(154,233)	
Hydro Plant	332	3	113,051,749	SG-P	26.070%	29,472,978	
Hydro Plant	332	3	30,389,979	SG-U	26.070%	7,922,771	
Other Plant	343	3	-	SG	26.070%	-	
Other Plant	343	3	30,157,070	SG	26.070%	7,862,051	
Other Plant	343	3	315,315	OR	Situs	315,315	
Other Plant	343	3	85,575,852	SG-W	26.070%	22,309,917	
Other Plant	343	3	3,947,715	SG	26.070%	1,029,183	
Transmission Plant	355	3	(3,027,279)	SG	26.070%	(789,222)	
Transmission Plant	355	3	(5,318,454)	SG	26.070%	(1,386,539)	
Transmission Plant	355	3	406,279,047	SG	26.070%	105,918,337	
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	26.070%	(65,309)	
General Plant	397	3	(554,012)	SG	26.070%	(144,433)	
General Plant	397	3	9,280,356	SG	26.070%	2,419,421	
General Plant	397	3	55,872,042	SO	27.173%	15,182,156	
General Plant	397	3	-	SG	26.070%	-	
General Plant	397	3	-	SG	26.070%	-	
General Plant	397	3	(1,789,712)	CN	30.990%	(554,630)	
General Plant	397	3	(268,157)	SE	25.068%	(67,222)	
Mining Plant	399	3	-	SE	25.068%	-	
			1,509,723,557			377,817,973	

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.

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	26.070%	-	
Intangible Plant	302	3	-	SG	26.070%	-	
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	25.068%	(18,407)	
Intangible Plant	302	3	(1,132,698)	SG	26.070%	(295,298)	
Intangible Plant	302	3	(83,981)	SG-P	26.070%	(21,894)	
Intangible Plant	302	3	(268,568)	SG-U	26.070%	(70,017)	
Intangible Plant	303	3	-	SG	26.070%	-	
Intangible Plant	303	3	44,779,220	SO	27.173%	12,167,894	
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			11,565,000	
Total Adjustment			1,552,171,305			389,382,973	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	27.173%	(23,116)	
Schedule M Addition - SG - Book Depr	SCHMAT	3	162,039	UT	Situs	-	
Schedule M Addition - UT - Book Depr	SCHMAT	3	(1,936,866)	SG	26.070%	(504,948)	
			(1,911,455)			(579,623)	
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	27.173%	1,346,665	
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	26.070%	(1,783,073)	
			106,172			(521,533)	
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	27.173%	5,683	
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	26.070%	124,150	
			469,962			142,510	
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	27.173%	331,099	
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	26.070%	(438,397)	
			26,104			(128,227)	

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.

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	27.173%	(353,218)	
ADIT - SG	282	3	(468,906)	UT	Situs	-	
ADIT - UT	282	3	1,205,387	SG	26.070%	314,249	
			(555,145)			(30,714)	
Sch. M Addition - Increm. Book Depr.	SCHMAT	3	(190,965)	SG	26.070%	(49,785)	
Sch. M Addition - Increm. Book Depr.	SCHMAT	3	(200,258.10)	SG	26.070%	(52,208)	
Sch. M Addition - Increm. Book Depr.	SCHMAT	3	5,547,174.14	SG	26.070%	1,446,167	
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	27.173%	482,336	
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	25.068%	(2,041)	
			14,531,780			4,274,727	
DIT Exp - Increm. Book Depr.	41110	3	46,952	SG	26.070%	12,241	
DIT Exp - Increm. Book Depr.	41110	3	49,237	SG	26.070%	12,836	
DIT Exp - Increm. Book Depr.	41110	3	(1,363,862)	SG	26.070%	(355,563)	
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	27.173%	(118,590)	
DIT Exp - Increm. Book Depr.	41110	3	11,988	CN	30.990%	3,715	
DIT Exp - Increm. Book Depr.	41110	3	2,002	SE	25.068%	502	
			(3,572,871)			(1,051,010)	
ADIT - Increm. Book Depr.	282	3	(23,476)	SG	26.070%	(6,120)	
ADIT - Increm. Book Depr.	282	3	(24,618)	SG	26.070%	(6,418)	
ADIT - Increm. Book Depr.	282	3	681,931	SG	26.070%	177,782	
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	27.173%	59,295	
ADIT - Increm. Book Depr.	282	3	(5,994)	CN	30.990%	(1,858)	
ADIT - Increm. Book Depr.	282	3	(1,001)	SE	25.068%	(251)	
			1,786,435			525,505	

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 - 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 - PowerTax adjustment and the final level of annualized book depreciation included in Adjustment 6.1/6.2.

PacifiCorp
Oregon General Rate Case - December 2023
Pro Forma Plant Additions and Retirements

Description	Account	Factor	End of Period June 2021 EPIS Balance	Test Period EPIS Balance (End of Period)	Adjustment to Test Period
Steam Production Plant:					
Pre-merger Pacific	312	SG	1,012,491,439	1,005,076,012	(7,415,427)
Pre-merger Utah	312	SG	1,059,174,518	1,049,480,541	(9,693,976)
Post-merger	312	SG	4,811,092,365	4,894,403,694	83,311,329
Post-merger	312	SG	1,266,851	1,266,851	-
Total Steam Plant			6,884,025,173	6,950,227,099	66,201,926
Hydro Production Plant:					
Pre-merger Pacific	332	SG-P	212,788,520	182,921,052	(29,867,468)
Pre-merger Utah	332	SG-U	39,865,127	39,273,524	(591,603)
Post-merger	332	SG-P	715,205,846	828,257,595	113,051,749
Post-merger	332	SG-U	152,896,613	183,286,592	30,389,979
Total Hydro Plant			1,120,756,105	1,233,738,762	112,982,656
Other Production Plant:					
Pre-merger Utah	343	SG	235,129	235,129	-
Post-merger	343	SG	1,925,969,509	1,956,126,579	30,157,070
Post-merger Wind	343	SG-W	3,160,796,216	3,246,372,067	85,575,852
Black Cap Solar	343	OR	74,986	390,301	315,315
Post-merger	343	SG	85,640,221	89,587,935	3,947,715
Total Other Production Plant			5,172,716,061	5,292,712,012	119,995,951
Transmission Plant:					
Pre-merger Pacific	355	SG	479,801,515	476,774,235	(3,027,279)
Pre-merger Utah	355	SG	620,673,594	615,355,140	(5,318,454)
Post-merger	355	SG	6,545,677,086	6,951,956,134	406,279,047
Total Transmission Plant			7,646,152,195	8,044,085,510	397,933,314
Distribution Plant:					
California	360-373	CA	290,384,821	342,198,781	51,813,960
Oregon	360-373	OR	2,324,681,909	2,484,328,127	159,646,218
Washington	360-373	WA	571,387,038	619,411,435	48,024,397
Eastern Wyoming	360-373	WYP	672,061,808	716,010,701	43,948,893
Utah	360-373	UT	3,342,346,441	3,671,327,019	328,980,577
Idaho	360-373	ID	397,879,329	444,343,741	46,464,412
Western Wyoming	360-373	WYU	155,050,984	154,550,860	(500,124)
Total Distribution Plant			7,753,792,330	8,432,170,664	678,378,334
General Plant:					
California	397	CA	23,110,673	23,960,387	849,714
Oregon	397	OR	224,756,896	244,185,593	19,428,697
Washington	397	WA	48,854,100	49,662,967	808,867
Eastern Wyoming	397	WYP	85,516,927	93,455,801	7,938,874
Utah	397	UT	237,752,017	277,740,291	39,988,273
Idaho	397	ID	51,387,414	54,885,092	3,497,677
Western Wyoming	397	WYU	18,200,958	17,630,222	(570,735)
Pre-merger Pacific	397	SG	1,007,315	756,805	(250,510)
Pre-merger Utah	397	SG	2,821,996	2,267,985	(554,012)
Post-merger	397	SG	302,412,630	311,692,986	9,280,356
General Office	397	SO	350,852,677	406,724,719	55,872,042
General Office	397	SG	-	-	-
General Office	397	SG	223,232	223,232	-
Customer Service	397	CN	17,295,589	15,505,877	(1,789,712)
Fuel Related	397	SE	3,318,698	3,050,541	(268,157)
Total General Plant			1,367,511,122	1,501,742,497	134,231,375

PacifiCorp
Oregon General Rate Case - December 2023
Pro Forma Plant Additions and Retirements

Description	Account	Factor	End of Period June 2021 EPIS Balance	Test Period EPIS Balance (End of Period)	Adjustment to Test Period
Mining Plant:					
Coal Mine	399	SE	1,822,901	1,822,901	-
Total Mining Plant			1,822,901	1,822,901	-
Intangible Plant:					
California	303	CA	481,167	481,167	-
Customer Service	303	CN	214,248,773	213,633,287	(615,486)
Pre-merger Utah	302	SG	477,596	477,596	-
Pre-merger Pacific	302	SG	-	-	-
Idaho	303	ID	4,371,145	4,369,593	(1,552)
Oregon	303	OR	4,616,002	4,609,463	(6,539)
Fuel Related	303	SE	9,106	(64,323)	(73,429)
Post-merger	302	SG	210,683,247	209,550,549	(1,132,698)
Hydro Relicensing	302	SG-P	177,566,825	177,482,844	(83,981)
Hydro Relicensing	302	SG-U	10,014,897	9,746,329	(268,568)
Post-merger	303	SG	-	-	-
General Office	303	SO	432,009,413	476,788,634	44,779,220
Utah	303	UT	(26,162,598)	(26,172,704)	(10,105)
Washington	303	WA	2,036,986	2,036,986	-
Eastern Wyoming	303	WYP	5,668,980	5,529,866	(139,114)
Western Wyoming	303	WYU	-	-	-
Total Intangible Plant			1,036,021,539	1,078,469,287	42,447,748
Total EPIS Balance			30,982,797,426	32,534,968,731	1,552,171,305
				Ref. 8.4.18	**Ref 8.4.1**

PacifiCorp
Oregon General Rate Case - December 2023
Pro Forma Plant Additions
and Retirements

Description	Factor	Adjusted EPIS Balance Jun 2021	Capital Additions	Retirements	Adjusted EPIS Balance Jul 2021	Capital Additions	Retirements	Adjusted EPIS Balance Aug 2021	Capital Additions	Retirements
Steam Production Plant:										
Pre-merger Pacific	SG	1,012,491,439	-	(411,968)	1,012,079,471	-	(411,968)	1,011,667,503	-	(411,968)
Pre-merger Utah	SG	1,059,174,518	-	(538,554)	1,058,635,963	-	(538,554)	1,058,097,409	-	(538,554)
Post-merger	SG	4,781,690,336	1,666,618	(3,118,406)	4,780,238,549	2,372,696	(3,118,406)	4,779,492,840	420,169	(3,118,406)
Geothermal - Blundell	SG	29,402,029	-	-	29,402,029	-	-	29,402,029	-	-
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-
Post-merger - Cholla	SG	1,266,851	-	-	1,266,851	-	-	1,266,851	-	-
Total Steam Plant		6,884,025,173	1,666,618	(4,068,928)	6,881,622,863	2,372,696	(4,068,928)	6,879,926,632	420,169	(4,068,928)
Hydro Production Plant:										
Pre-merger Pacific	SG	183,823,226	-	(50,121)	183,773,105	-	(50,121)	183,722,984	-	(50,121)
Pre-merger Utah	SG	39,865,127	-	(32,867)	39,832,260	-	(32,867)	39,799,393	-	(32,867)
Post-merger	SG-P	649,962,674	(321,167)	(183,427)	649,458,080	32,086	(183,427)	649,306,738	1,273,181	(183,427)
Post-merger	SG-U	152,896,613	206,846	(37,209)	153,066,250	(69,239)	(37,209)	152,959,802	533,219	(37,209)
Klamath - New Capital	SG-P	2,703,876	-	-	2,703,876	-	-	2,703,876	281,024	-
Klamath	SG-P	91,504,591	-	-	91,504,591	-	-	91,504,591	-	-
Total Hydro Plant		1,120,756,105	(114,320)	(303,624)	1,120,338,161	(37,153)	(303,624)	1,119,997,384	2,087,424	(303,624)
Other Production Plant:										
Pre-merger Utah	SG	235,129	-	-	235,129	-	-	235,129	-	-
Post-merger	SG	1,925,969,509	(85,685)	(2,040,058)	1,923,843,767	105,347	(2,040,058)	1,921,909,056	(98,126)	(2,040,058)
Post-merger Wind	SG-W	3,160,796,216	30,277,179	(238,555)	3,190,834,840	6,686,559	(238,555)	3,197,282,844	11,781,414	(238,555)
Black Cap Solar	OR	74,986	-	-	74,986	-	-	74,986	-	-
Post-merger	SG	85,640,221	1,317,138	(46,204)	86,911,154	6,803	(46,204)	86,871,753	3,301,375	(46,204)
Total Other Plant		5,172,716,061	31,508,632	(2,324,817)	5,201,899,876	6,798,710	(2,324,817)	5,206,373,769	14,984,662	(2,324,817)
Transmission Plant:										
Pre-merger Pacific	SG	479,801,515	-	(168,182)	479,633,333	-	(168,182)	479,465,150	-	(168,182)
Pre-merger Utah	SG	620,673,594	-	(295,470)	620,378,125	-	(295,470)	620,082,655	-	(295,470)
Post-merger	SG	6,545,677,086	11,060,066	(726,705)	6,556,010,447	53,616	(726,705)	6,555,337,357	18,356,928	(726,705)
Total Transmission Plant		7,646,152,195	11,060,066	(1,190,357)	7,656,021,904	53,616	(1,190,357)	7,654,885,162	18,356,928	(1,190,357)
Distribution Plant:										
California	CA	290,384,821	645,415	(145,707)	290,884,529	536,179	(145,707)	291,275,000	1,600,597	(145,707)
Oregon	OR	2,324,681,909	5,282,606	(1,763,593)	2,328,200,922	5,414,252	(1,763,593)	2,331,851,581	16,924,526	(1,763,593)
Washington	WA	571,387,038	2,054,355	(198,825)	573,242,568	1,452,522	(198,825)	574,496,264	1,609,293	(198,825)
Eastern Wyoming	WYP	672,061,808	2,347,876	(271,721)	674,137,963	1,553,562	(271,721)	675,419,805	2,621,401	(271,721)
Utah	UT	3,342,346,441	15,086,395	(1,414,241)	3,356,018,595	8,549,801	(1,414,241)	3,363,154,155	24,191,247	(1,414,241)
Idaho	ID	397,879,329	991,413	(155,146)	398,715,596	1,147,132	(155,146)	399,707,583	2,431,771	(155,146)
Western Wyoming	WYU	155,050,984	-	(27,785)	155,023,199	-	(27,785)	154,995,414	-	(27,785)
Total Distribution Plant		7,753,792,330	26,408,059	(3,977,018)	7,776,223,372	18,653,447	(3,977,018)	7,790,899,802	49,378,834	(3,977,018)

PacifiCorp
Oregon General Rate Case - December 2023
Pro Forma Plant Additions
and Retirements

Description	Factor	Adjusted EPIS Balance Jun 2021	Capital Additions	Retirements	Adjusted EPIS Balance Jul 2021	Capital Additions	Retirements	Adjusted EPIS Balance Aug 2021	Capital Additions	Retirements
General Plant:										
California	CA	23,110,673	7,486	(43,689)	23,074,470	19,869	(43,689)	23,050,650	18,876	(43,689)
Oregon	OR	224,756,896	139,341	(323,194)	224,573,042	165,583	(323,194)	224,415,430	930,890	(323,194)
Washington	WA	48,854,100	18,419	(115,214)	48,757,305	(3,465)	(115,214)	48,638,626	309,906	(115,214)
Eastern Wyoming	WYP	85,516,927	25,070	(254,299)	85,287,698	211,362	(254,299)	85,244,761	603,199	(254,299)
Utah	UT	237,752,017	544,265	(479,305)	237,816,977	2,470,547	(479,305)	239,808,219	1,202,961	(479,305)
Idaho	ID	51,387,414	21,199	(68,917)	51,339,697	44,593	(68,917)	51,315,374	165,905	(68,917)
Western Wyoming	WYU	18,200,958	-	(31,708)	18,169,250	-	(31,708)	18,137,543	-	(31,708)
Pre-merger Pacific	SG	1,007,315	-	(13,917)	993,398	-	(13,917)	979,480	-	(13,917)
Pre-merger Utah	SG	2,821,996	-	(30,778)	2,791,218	-	(30,778)	2,760,439	-	(30,778)
Post-merger	SG	302,412,630	277,423	(578,398)	302,111,654	295,555	(578,398)	301,828,810	116,386	(578,398)
General Office	SO	350,852,677	742,036	(1,303,426)	350,291,286	1,504,749	(1,303,426)	350,492,609	6,213,747	(1,303,426)
General Office	SG	-	-	-	-	-	-	-	-	-
General Office	SG	223,232	-	-	223,232	-	-	223,232	-	-
Customer Service	CN	17,295,589	-	(99,428)	17,196,160	-	(99,428)	17,096,732	-	(99,428)
Fuel Related	SE	3,318,698	-	(14,898)	3,303,800	-	(14,898)	3,288,902	-	(14,898)
Total General Plant		1,367,511,122	1,775,238	(3,357,172)	1,365,929,188	4,708,792	(3,357,172)	1,367,280,809	9,561,870	(3,357,172)
Mining Plant:										
Coal Mine	SE	1,822,901	-	-	1,822,901	-	-	1,822,901	-	-
Total Mining Plant		1,822,901	-	-	1,822,901	-	-	1,822,901	-	-
Intangible Plant:										
California	CA	481,167	-	-	481,167	-	-	481,167	-	-
Customer Service	CN	214,248,773	-	(34,194)	214,214,579	-	(34,194)	214,180,385	-	(34,194)
Pre-merger Utah	SG	477,596	-	-	477,596	-	-	477,596	-	-
Pre-merger Pacific	SG	-	-	-	-	-	-	-	-	-
Idaho	ID	4,371,145	-	(86)	4,371,059	-	(86)	4,370,973	-	(86)
Oregon	OR	4,616,002	-	(363)	4,615,639	-	(363)	4,615,275	-	(363)
Fuel Related	SE	9,106	-	(4,079)	5,026	-	(4,079)	947	-	(4,079)
Post-merger	SG	210,683,247	-	(62,928)	210,620,319	-	(62,928)	210,557,391	-	(62,928)
Klamath Hydro Relicensing	SG-P	74,111,750	-	-	74,111,750	-	-	74,111,750	-	-
Hydro Relicensing	SG-P	103,455,075	-	(4,666)	103,450,409	-	(4,666)	103,445,744	-	(4,666)
Hydro Relicensing	SG-U	10,014,897	-	(14,920)	9,999,977	-	(14,920)	9,985,056	-	(14,920)
General Office	SO	432,009,413	2,550,130	(1,123,079)	433,436,464	(849,846)	(1,123,079)	431,463,539	3,144,709	(1,123,079)
Utah	UT	(26,162,598)	-	(561)	(26,163,160)	-	(561)	(26,163,721)	-	(561)
Washington	WA	2,036,986	-	-	2,036,986	-	-	2,036,986	-	-
Eastern Wyoming	WYP	5,668,980	-	(7,729)	5,661,251	-	(7,729)	5,653,523	-	(7,729)
Western Wyoming	WYU	-	-	-	-	-	-	-	-	-
Total Intangible Plant		1,036,021,539	2,550,130	(1,252,606)	1,037,319,063	(849,846)	(1,252,606)	1,035,216,612	3,144,709	(1,252,606)
Total		30,982,797,426	74,854,424	(16,474,521)	31,041,177,329	31,700,262	(16,474,521)	31,056,403,070	97,934,596	(16,474,521)

PacifiCorp
Oregon General Rate Case - December 2023
Pro Forma Plant Additions
and Retirements

Description	Factor	Adjusted EPIS Balance Sep 2021	Capital Additions	Retirements	Adjusted EPIS Balance Oct 2021	Capital Additions	Retirements	Adjusted EPIS Balance Nov 2021	Capital Additions	Retirements
Steam Production Plant:										
Pre-merger Pacific	SG	1,011,255,535	-	(411,968)	1,010,843,566	-	(411,968)	1,010,431,598	-	(411,968)
Pre-merger Utah	SG	1,057,558,855	-	(538,554)	1,057,020,301	-	(538,554)	1,056,481,746	-	(538,554)
Post-merger	SG	4,776,794,603	13,902,238	(3,118,406)	4,787,578,436	2,776,222	(3,118,406)	4,787,236,252	11,239,740	(3,118,406)
Geothermal - Blundell	SG	29,402,029	-	-	29,402,029	-	-	29,402,029	-	-
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-
Post-merger - Cholla	SG	1,266,851	-	-	1,266,851	-	-	1,266,851	-	-
Total Steam Plant		6,876,277,873	13,902,238	(4,068,928)	6,886,111,183	2,776,222	(4,068,928)	6,884,818,477	11,239,740	(4,068,928)
Hydro Production Plant:										
Pre-merger Pacific	SG	183,672,864	-	(50,121)	183,622,743	-	(50,121)	183,572,622	-	(50,121)
Pre-merger Utah	SG	39,766,526	-	(32,867)	39,733,659	-	(32,867)	39,700,792	-	(32,867)
Post-merger	SG-P	650,396,491	1,960,975	(183,427)	652,174,038	3,841,421	(183,427)	655,832,032	13,545,140	(183,427)
Post-merger	SG-U	153,455,812	265,198	(37,209)	153,683,801	1,389,574	(37,209)	155,036,166	6,998,790	(37,209)
Klamath - New Capital	SG-P	2,984,900	73,294	-	3,058,193	1,112,940	-	4,171,133	-	-
Klamath	SG-P	91,504,591	-	-	91,504,591	-	-	91,504,591	-	-
Total Hydro Plant		1,121,781,183	2,299,466	(303,624)	1,123,777,025	6,343,935	(303,624)	1,129,817,336	20,543,931	(303,624)
Other Production Plant:										
Pre-merger Utah	SG	235,129	-	-	235,129	-	-	235,129	-	-
Post-merger	SG	1,919,770,872	28,585,744	(2,040,058)	1,946,316,558	307,145	(2,040,058)	1,944,583,646	468,979	(2,040,058)
Post-merger Wind	SG-W	3,208,825,703	19,075,668	(238,555)	3,227,662,816	3,450,399	(238,555)	3,230,874,661	3,651,610	(238,555)
Black Cap Solar	OR	74,986	-	-	74,986	-	-	74,986	255,090	-
Post-merger	SG	90,126,924	6,803	(46,204)	90,087,523	6,803	(46,204)	90,048,121	6,803	(46,204)
Total Other Plant		5,219,033,614	47,668,215	(2,324,817)	5,264,377,012	3,764,348	(2,324,817)	5,265,816,543	4,382,483	(2,324,817)
Transmission Plant:										
Pre-merger Pacific	SG	479,296,968	-	(168,182)	479,128,786	-	(168,182)	478,960,604	-	(168,182)
Pre-merger Utah	SG	619,787,185	-	(295,470)	619,491,716	-	(295,470)	619,196,246	-	(295,470)
Post-merger	SG	6,572,967,580	40,334,673	(726,705)	6,612,575,548	41,469,010	(726,705)	6,653,317,852	38,893,112	(726,705)
Total Transmission Plant		7,672,051,734	40,334,673	(1,190,357)	7,711,196,050	41,469,010	(1,190,357)	7,751,474,702	38,893,112	(1,190,357)
Distribution Plant:										
California	CA	292,729,890	1,193,784	(145,707)	293,777,967	11,459,835	(145,707)	305,092,094	1,201,797	(145,707)
Oregon	OR	2,347,012,514	5,790,056	(1,763,593)	2,351,038,977	4,686,243	(1,763,593)	2,353,961,626	10,416,317	(1,763,593)
Washington	WA	575,906,732	1,134,154	(198,825)	576,842,061	946,235	(198,825)	577,589,471	1,384,719	(198,825)
Eastern Wyoming	WYP	677,769,484	2,290,590	(271,721)	679,788,354	2,206,195	(271,721)	681,722,828	13,525,926	(271,721)
Utah	UT	3,385,931,161	22,655,780	(1,414,241)	3,407,172,700	11,999,512	(1,414,241)	3,417,757,971	23,813,278	(1,414,241)
Idaho	ID	401,984,208	3,665,053	(155,146)	405,494,115	7,485,792	(155,146)	412,824,762	2,823,622	(155,146)
Western Wyoming	WYU	154,967,630	-	(27,785)	154,939,845	-	(27,785)	154,912,060	-	(27,785)
Total Distribution Plant		7,836,301,618	36,729,418	(3,977,018)	7,869,054,018	38,783,812	(3,977,018)	7,903,860,813	53,165,659	(3,977,018)

PacifiCorp
Oregon General Rate Case - December 2023
Pro Forma Plant Additions
and Retirements

Description	Factor	Adjusted EPIS Balance Sep 2021	Capital Additions	Retirements	Adjusted EPIS Balance Oct 2021	Capital Additions	Retirements	Adjusted EPIS Balance Nov 2021	Capital Additions	Retirements
General Plant:										
California	CA	23,025,838	70,798	(43,689)	23,052,947	11,560	(43,689)	23,020,818	6,804	(43,689)
Oregon	OR	225,023,126	1,473,789	(323,194)	226,173,721	1,134,904	(323,194)	226,985,431	7,498,427	(323,194)
Washington	WA	48,833,318	191,512	(115,214)	48,909,616	146,783	(115,214)	48,941,185	185,591	(115,214)
Eastern Wyoming	WYP	85,593,662	734,332	(254,299)	86,073,695	498,337	(254,299)	86,317,734	3,020,677	(254,299)
Utah	UT	240,531,874	3,197,351	(479,305)	243,249,919	2,906,931	(479,305)	245,677,545	7,500,933	(479,305)
Idaho	ID	51,412,362	369,636	(68,917)	51,713,081	277,497	(68,917)	51,921,662	1,204,478	(68,917)
Western Wyoming	WYU	18,105,835	-	(31,708)	18,074,128	-	(31,708)	18,042,420	-	(31,708)
Pre-merger Pacific	SG	965,563	-	(13,917)	951,646	-	(13,917)	937,729	-	(13,917)
Pre-merger Utah	SG	2,729,661	-	(30,778)	2,698,882	-	(30,778)	2,668,104	-	(30,778)
Post-merger	SG	301,366,798	604,717	(578,398)	301,393,117	957,134	(578,398)	301,771,852	5,529,597	(578,398)
General Office	SO	355,402,930	24,734,212	(1,303,426)	378,833,715	7,178,989	(1,303,426)	384,709,278	8,353,715	(1,303,426)
General Office	SG	-	-	-	-	-	-	-	-	-
General Office	SG	223,232	-	-	223,232	-	-	223,232	-	-
Customer Service	CN	16,997,303	-	(99,428)	16,897,875	-	(99,428)	16,798,447	-	(99,428)
Fuel Related	SE	3,274,005	-	(14,898)	3,259,107	-	(14,898)	3,244,210	-	(14,898)
Total General Plant		1,373,485,507	31,376,347	(3,357,172)	1,401,504,682	13,112,136	(3,357,172)	1,411,259,647	33,300,223	(3,357,172)
Mining Plant:										
Coal Mine	SE	1,822,901	-	-	1,822,901	-	-	1,822,901	-	-
Total Mining Plant		1,822,901	-	-	1,822,901	-	-	1,822,901	-	-
Intangible Plant:										
California	CA	481,167	-	-	481,167	-	-	481,167	-	-
Customer Service	CN	214,146,192	-	(34,194)	214,111,998	-	(34,194)	214,077,804	-	(34,194)
Pre-merger Utah	SG	477,596	-	-	477,596	-	-	477,596	-	-
Pre-merger Pacific	SG	-	-	-	-	-	-	-	-	-
Idaho	ID	4,370,886	-	(86)	4,370,800	-	(86)	4,370,714	-	(86)
Oregon	OR	4,614,912	-	(363)	4,614,549	-	(363)	4,614,186	-	(363)
Fuel Related	SE	(3,132)	-	(4,079)	(7,212)	-	(4,079)	(11,291)	-	(4,079)
Post-merger	SG	210,494,464	-	(62,928)	210,431,536	-	(62,928)	210,368,609	-	(62,928)
Klamath Hydro Relicensing	SG-P	74,111,750	-	-	74,111,750	-	-	74,111,750	-	-
Hydro Relicensing	SG-P	103,441,078	-	(4,666)	103,436,412	-	(4,666)	103,431,747	-	(4,666)
Hydro Relicensing	SG-U	9,970,136	-	(14,920)	9,955,215	-	(14,920)	9,940,295	-	(14,920)
General Office	SO	433,485,169	1,412,688	(1,123,079)	433,774,777	8,808,993	(1,123,079)	441,460,691	6,240,861	(1,123,079)
Utah	UT	(26,164,283)	-	(561)	(26,164,844)	-	(561)	(26,165,405)	-	(561)
Washington	WA	2,036,986	-	-	2,036,986	-	-	2,036,986	-	-
Eastern Wyoming	WYP	5,645,794	-	(7,729)	5,638,066	-	(7,729)	5,630,337	-	(7,729)
Western Wyoming	WYU	-	-	-	-	-	-	-	-	-
Total Intangible Plant		1,037,108,715	1,412,688	(1,252,606)	1,037,268,798	8,808,993	(1,252,606)	1,044,825,185	6,240,861	(1,252,606)
Total		31,137,863,145	173,723,045	(16,474,521)	31,295,111,669	115,058,455	(16,474,521)	31,393,695,603	167,766,008	(16,474,521)

PacifiCorp
Oregon General Rate Case - December 2023
Pro Forma Plant Additions
and Retirements

Description	Factor	Adjusted EPIS Balance Dec 2021	Capital Additions	Retirements	Adjusted EPIS Balance Jan 2022	Capital Additions	Retirements	Adjusted EPIS Balance Feb 2022	Capital Additions	Retirements
Steam Production Plant:										
Pre-merger Pacific	SG	1,010,019,630	-	(411,968)	1,009,607,662	-	(411,968)	1,009,195,694	-	(411,968)
Pre-merger Utah	SG	1,055,943,192	-	(538,554)	1,055,404,638	-	(538,554)	1,054,866,084	-	(538,554)
Post-merger	SG	4,795,357,586	(559,421)	(3,118,406)	4,791,679,759	(283,879)	(3,118,406)	4,788,277,475	100,642	(3,118,406)
Geothermal - Blundell	SG	29,402,029	-	-	29,402,029	-	-	29,402,029	-	-
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-
Post-merger - Cholla	SG	1,266,851	-	-	1,266,851	-	-	1,266,851	-	-
Total Steam Plant		6,891,989,289	(559,421)	(4,068,928)	6,887,360,939	(283,879)	(4,068,928)	6,883,008,133	100,642	(4,068,928)
Hydro Production Plant:										
Pre-merger Pacific	SG	183,522,501	-	(50,121)	183,472,380	-	(50,121)	183,422,260	-	(50,121)
Pre-merger Utah	SG	39,667,926	-	(32,867)	39,635,059	-	(32,867)	39,602,192	-	(32,867)
Post-merger	SG-P	669,193,744	48,940	(183,427)	669,059,256	2,852,738	(183,427)	671,728,567	1,379,843	(183,427)
Post-merger	SG-U	161,997,747	(64,385)	(37,209)	161,896,153	(64,385)	(37,209)	161,794,558	(64,385)	(37,209)
Klamath - New Capital	SG-P	4,171,133	-	-	4,171,133	-	-	4,171,133	-	-
Klamath	SG-P	91,504,591	-	-	91,504,591	-	-	91,504,591	-	-
Total Hydro Plant		1,150,057,642	(15,446)	(303,624)	1,149,738,572	2,788,353	(303,624)	1,152,223,301	1,315,458	(303,624)
Other Production Plant:										
Pre-merger Utah	SG	235,129	-	-	235,129	-	-	235,129	-	-
Post-merger	SG	1,943,012,568	(22,862)	(2,040,058)	1,940,949,647	(22,862)	(2,040,058)	1,938,886,727	(22,862)	(2,040,058)
Post-merger Wind	SG-W	3,234,287,716	1,241,001	(238,555)	3,235,290,162	1,241,001	(238,555)	3,236,292,608	1,241,001	(238,555)
Black Cap Solar	OR	330,076	5,019	-	335,095	5,019	-	340,114	5,019	-
Post-merger	SG	90,008,720	4,057	(46,204)	89,966,573	4,057	(46,204)	89,924,426	4,057	(46,204)
Total Other Plant		5,267,874,210	1,227,215	(2,324,817)	5,266,776,607	1,227,215	(2,324,817)	5,265,679,005	1,227,215	(2,324,817)
Transmission Plant:										
Pre-merger Pacific	SG	478,792,422	-	(168,182)	478,624,239	-	(168,182)	478,456,057	-	(168,182)
Pre-merger Utah	SG	618,900,776	-	(295,470)	618,605,307	-	(295,470)	618,309,837	-	(295,470)
Post-merger	SG	6,691,484,258	3,647,374	(726,705)	6,694,404,927	4,955,659	(726,705)	6,698,633,881	8,841,942	(726,705)
Total Transmission Plant		7,789,177,457	3,647,374	(1,190,357)	7,791,634,473	4,955,659	(1,190,357)	7,795,399,775	8,841,942	(1,190,357)
Distribution Plant:										
California	CA	306,148,183	1,027,416	(145,707)	307,029,892	1,338,540	(145,707)	308,222,724	3,933,252	(145,707)
Oregon	OR	2,362,614,351	3,352,293	(1,763,593)	2,364,203,051	3,698,605	(1,763,593)	2,366,138,063	15,338,378	(1,763,593)
Washington	WA	578,775,365	961,278	(198,825)	579,537,818	1,024,937	(198,825)	580,363,930	2,379,135	(198,825)
Eastern Wyoming	WYP	694,977,033	1,545,034	(271,721)	696,250,347	1,524,579	(271,721)	697,503,205	1,766,289	(271,721)
Utah	UT	3,440,157,008	12,465,084	(1,414,241)	3,451,207,851	15,826,645	(1,414,241)	3,465,620,255	24,013,749	(1,414,241)
Idaho	ID	415,493,238	2,591,755	(155,146)	417,929,847	1,944,442	(155,146)	419,719,143	2,855,436	(155,146)
Western Wyoming	WYU	154,884,276	-	(27,785)	154,856,491	-	(27,785)	154,828,706	-	(27,785)
Total Distribution Plant		7,953,049,454	21,942,860	(3,977,018)	7,971,015,296	25,357,748	(3,977,018)	7,992,396,027	50,286,239	(3,977,018)

PacifiCorp
Oregon General Rate Case - December 2023
Pro Forma Plant Additions
and Retirements

Description	Factor	Adjusted EPIS Balance Dec 2021	Capital Additions	Retirements	Adjusted EPIS Balance Jan 2022	Capital Additions	Retirements	Adjusted EPIS Balance Feb 2022	Capital Additions	Retirements
General Plant:										
California	CA	22,983,934	71,628	(43,689)	23,011,873	26,648	(43,689)	22,994,833	73,832	(43,689)
Oregon	OR	234,160,664	552,726	(323,194)	234,390,196	215,415	(323,194)	234,282,417	578,574	(323,194)
Washington	WA	49,011,562	108,868	(115,214)	49,005,216	41,235	(115,214)	48,931,237	112,263	(115,214)
Eastern Wyoming	WYP	89,084,112	548,873	(254,299)	89,378,687	229,406	(254,299)	89,353,794	271,212	(254,299)
Utah	UT	252,699,172	2,539,502	(479,305)	254,759,368	1,701,640	(479,305)	255,981,703	1,997,019	(479,305)
Idaho	ID	53,057,223	218,201	(68,917)	53,206,508	111,884	(68,917)	53,249,475	126,350	(68,917)
Western Wyoming	WYU	18,010,713	-	(31,708)	17,979,005	-	(31,708)	17,947,298	-	(31,708)
Pre-merger Pacific	SG	923,811	-	(13,917)	909,894	-	(13,917)	895,977	-	(13,917)
Pre-merger Utah	SG	2,637,326	-	(30,778)	2,606,547	-	(30,778)	2,575,769	-	(30,778)
Post-merger	SG	306,723,051	226,672	(578,398)	306,371,325	262,530	(578,398)	306,055,456	305,596	(578,398)
General Office	SO	391,759,567	1,250,598	(1,303,426)	391,706,738	1,230,754	(1,303,426)	391,634,066	727,858	(1,303,426)
General Office	SG	-	-	-	-	-	-	-	-	-
General Office	SG	223,232	-	-	223,232	-	-	223,232	-	-
Customer Service	CN	16,699,018	-	(99,428)	16,599,590	-	(99,428)	16,500,161	-	(99,428)
Fuel Related	SE	3,229,312	-	(14,898)	3,214,414	-	(14,898)	3,199,517	-	(14,898)
Total General Plant		1,441,202,698	5,517,069	(3,357,172)	1,443,362,595	3,819,511	(3,357,172)	1,443,824,935	4,192,703	(3,357,172)
Mining Plant:										
Coal Mine	SE	1,822,901	-	-	1,822,901	-	-	1,822,901	-	-
Total Mining Plant		1,822,901	-	-	1,822,901	-	-	1,822,901	-	-
Intangible Plant:										
California	CA	481,167	-	-	481,167	-	-	481,167	-	-
Customer Service	CN	214,043,611	-	(34,194)	214,009,417	-	(34,194)	213,975,223	-	(34,194)
Pre-merger Utah	SG	477,596	-	-	477,596	-	-	477,596	-	-
Pre-merger Pacific	SG	-	-	-	-	-	-	-	-	-
Idaho	ID	4,370,628	-	(86)	4,370,541	-	(86)	4,370,455	-	(86)
Oregon	OR	4,613,822	-	(363)	4,613,459	-	(363)	4,613,096	-	(363)
Fuel Related	SE	(15,371)	-	(4,079)	(19,450)	-	(4,079)	(23,529)	-	(4,079)
Post-merger	SG	210,305,681	-	(62,928)	210,242,753	-	(62,928)	210,179,826	-	(62,928)
Klamath Hydro Relicensing	SG-P	74,111,750	-	-	74,111,750	-	-	74,111,750	-	-
Hydro Relicensing	SG-P	103,427,081	-	(4,666)	103,422,416	-	(4,666)	103,417,750	-	(4,666)
Hydro Relicensing	SG-U	9,925,374	-	(14,920)	9,910,454	-	(14,920)	9,895,534	-	(14,920)
General Office	SO	446,578,473	4,201,860	(1,123,079)	449,657,253	526,670	(1,123,079)	449,060,844	1,346,770	(1,123,079)
Utah	UT	(26,165,967)	-	(561)	(26,166,528)	-	(561)	(26,167,090)	-	(561)
Washington	WA	2,036,986	-	-	2,036,986	-	-	2,036,986	-	-
Eastern Wyoming	WYP	5,622,608	-	(7,729)	5,614,880	-	(7,729)	5,607,151	-	(7,729)
Western Wyoming	WYU	-	-	-	-	-	-	-	-	-
Total Intangible Plant		1,049,813,441	4,201,860	(1,252,606)	1,052,762,695	526,670	(1,252,606)	1,052,036,760	1,346,770	(1,252,606)
Total		31,544,987,089	35,961,511	(16,474,521)	31,564,474,079	38,391,278	(16,474,521)	31,586,390,835	67,310,969	(16,474,521)

PacifiCorp
Oregon General Rate Case - December 2023
Pro Forma Plant Additions
and Retirements

Description	Factor	Adjusted EPIS Balance Mar 2022	Capital Additions	Retirements	Adjusted EPIS Balance Apr 2022	Capital Additions	Retirements	Adjusted EPIS Balance May 2022	Capital Additions	Retirements
Steam Production Plant:										
Pre-merger Pacific	SG	1,008,783,726	-	(411,968)	1,008,371,757	-	(411,968)	1,007,959,789	-	(411,968)
Pre-merger Utah	SG	1,054,327,529	-	(538,554)	1,053,788,975	-	(538,554)	1,053,250,421	-	(538,554)
Post-merger	SG	4,785,259,712	23,571,636	(3,118,406)	4,805,712,942	36,258,316	(3,118,406)	4,838,852,852	14,382,932	(3,118,406)
Geothermal - Blundell	SG	29,402,029	-	-	29,402,029	-	-	29,402,029	-	-
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-
Post-merger - Cholla	SG	1,266,851	-	-	1,266,851	-	-	1,266,851	-	-
Total Steam Plant		6,879,039,847	23,571,636	(4,068,928)	6,898,542,555	36,258,316	(4,068,928)	6,930,731,943	14,382,932	(4,068,928)
Hydro Production Plant:										
Pre-merger Pacific	SG	183,372,139	-	(50,121)	183,322,018	-	(50,121)	183,271,897	-	(50,121)
Pre-merger Utah	SG	39,569,325	-	(32,867)	39,536,458	-	(32,867)	39,503,591	-	(32,867)
Post-merger	SG-P	672,924,983	368,832	(183,427)	673,110,388	782,015	(183,427)	673,708,975	11,896,857	(183,427)
Post-merger	SG-U	161,692,964	(64,385)	(37,209)	161,591,370	(64,385)	(37,209)	161,489,775	4,980	(37,209)
Klamath - New Capital	SG-P	4,171,133	-	-	4,171,133	-	-	4,171,133	-	-
Klamath	SG-P	91,504,591	-	-	91,504,591	-	-	91,504,591	-	-
Total Hydro Plant		1,153,235,135	304,447	(303,624)	1,153,235,958	717,630	(303,624)	1,153,649,963	11,901,837	(303,624)
Other Production Plant:										
Pre-merger Utah	SG	235,129	-	-	235,129	-	-	235,129	-	-
Post-merger	SG	1,936,823,807	23,394,000	(2,040,058)	1,958,177,749	3,538,513	(2,040,058)	1,959,676,204	914,001	(2,040,058)
Post-merger Wind	SG-W	3,237,295,054	1,241,001	(238,555)	3,238,297,500	1,296,001	(238,555)	3,239,354,946	1,241,001	(238,555)
Black Cap Solar	OR	345,132	5,019	-	350,151	5,019	-	355,170	5,019	-
Post-merger	SG	89,882,279	4,057	(46,204)	89,840,132	4,057	(46,204)	89,797,985	26,451	(46,204)
Total Other Plant		5,264,581,402	24,644,077	(2,324,817)	5,286,900,662	4,843,590	(2,324,817)	5,289,419,434	2,186,471	(2,324,817)
Transmission Plant:										
Pre-merger Pacific	SG	478,287,875	-	(168,182)	478,119,693	-	(168,182)	477,951,511	-	(168,182)
Pre-merger Utah	SG	618,014,367	-	(295,470)	617,718,898	-	(295,470)	617,423,428	-	(295,470)
Post-merger	SG	6,706,749,117	11,649,338	(726,705)	6,717,671,749	29,104,520	(726,705)	6,746,049,564	19,358,660	(726,705)
Total Transmission Plant		7,803,051,360	11,649,338	(1,190,357)	7,813,510,340	29,104,520	(1,190,357)	7,841,424,503	19,358,660	(1,190,357)
Distribution Plant:										
California	CA	312,010,268	1,178,065	(145,707)	313,042,626	5,710,843	(145,707)	318,607,761	6,894,949	(145,707)
Oregon	OR	2,379,712,848	7,204,251	(1,763,593)	2,385,153,507	29,158,579	(1,763,593)	2,412,548,493	20,595,283	(1,763,593)
Washington	WA	582,544,240	2,042,714	(198,825)	584,388,128	3,093,232	(198,825)	587,282,535	2,944,352	(198,825)
Eastern Wyoming	WYP	698,997,773	1,908,736	(271,721)	700,634,788	2,609,027	(271,721)	702,972,094	2,196,900	(271,721)
Utah	UT	3,488,219,763	17,113,779	(1,414,241)	3,503,919,302	35,695,541	(1,414,241)	3,538,200,602	21,006,603	(1,414,241)
Idaho	ID	422,419,434	2,232,285	(155,146)	424,496,574	3,208,573	(155,146)	427,550,001	2,154,386	(155,146)
Western Wyoming	WYU	154,800,922	-	(27,785)	154,773,137	-	(27,785)	154,745,352	-	(27,785)
Total Distribution Plant		8,038,705,249	31,679,830	(3,977,018)	8,066,408,061	79,475,795	(3,977,018)	8,141,906,838	55,792,474	(3,977,018)

PacifiCorp
Oregon General Rate Case - December 2023
Pro Forma Plant Additions
and Retirements

Description	Factor	Adjusted EPIS Balance Mar 2022	Capital Additions	Retirements	Adjusted EPIS Balance Apr 2022	Capital Additions	Retirements	Adjusted EPIS Balance May 2022	Capital Additions	Retirements
General Plant:										
California	CA	23,024,976	17,091	(43,689)	22,998,378	36,774	(43,689)	22,991,464	80,819	(43,689)
Oregon	OR	234,537,796	784,741	(323,194)	234,999,343	976,084	(323,194)	235,652,233	1,467,605	(323,194)
Washington	WA	48,928,286	96,426	(115,214)	48,909,498	129,074	(115,214)	48,923,357	215,570	(115,214)
Eastern Wyoming	WYP	89,370,708	444,456	(254,299)	89,560,865	564,258	(254,299)	89,870,825	725,731	(254,299)
Utah	UT	257,499,416	2,242,747	(479,305)	259,262,858	3,053,717	(479,305)	261,837,269	3,452,282	(479,305)
Idaho	ID	53,306,909	125,449	(68,917)	53,363,441	165,495	(68,917)	53,460,019	219,875	(68,917)
Western Wyoming	WYU	17,915,590	-	(31,708)	17,883,883	-	(31,708)	17,852,175	-	(31,708)
Pre-merger Pacific	SG	882,060	-	(13,917)	868,143	-	(13,917)	854,225	-	(13,917)
Pre-merger Utah	SG	2,544,990	-	(30,778)	2,514,212	-	(30,778)	2,483,433	-	(30,778)
Post-merger	SG	305,782,654	349,542	(578,398)	305,553,798	305,628	(578,398)	305,281,027	305,942	(578,398)
General Office	SO	391,058,497	1,396,945	(1,303,426)	391,152,016	2,435,058	(1,303,426)	392,283,647	4,339,213	(1,303,426)
General Office	SG	-	-	-	-	-	-	-	-	-
General Office	SG	223,232	-	-	223,232	-	-	223,232	-	-
Customer Service	CN	16,400,733	-	(99,428)	16,301,304	-	(99,428)	16,201,876	-	(99,428)
Fuel Related	SE	3,184,619	-	(14,898)	3,169,722	-	(14,898)	3,154,824	-	(14,898)
Total General Plant		1,444,660,466	5,457,397	(3,357,172)	1,446,760,692	7,666,087	(3,357,172)	1,451,069,607	10,807,036	(3,357,172)
Mining Plant:										
Coal Mine	SE	1,822,901	-	-	1,822,901	-	-	1,822,901	-	-
Total Mining Plant		1,822,901	-	-	1,822,901	-	-	1,822,901	-	-
Intangible Plant:										
California	CA	481,167	-	-	481,167	-	-	481,167	-	-
Customer Service	CN	213,941,030	-	(34,194)	213,906,836	-	(34,194)	213,872,642	-	(34,194)
Pre-merger Utah	SG	477,596	-	-	477,596	-	-	477,596	-	-
Pre-merger Pacific	SG	-	-	-	-	-	-	-	-	-
Idaho	ID	4,370,369	-	(86)	4,370,283	-	(86)	4,370,196	-	(86)
Oregon	OR	4,612,732	-	(363)	4,612,369	-	(363)	4,612,006	-	(363)
Fuel Related	SE	(27,609)	-	(4,079)	(31,688)	-	(4,079)	(35,767)	-	(4,079)
Post-merger	SG	210,116,898	-	(62,928)	210,053,970	-	(62,928)	209,991,043	-	(62,928)
Klamath Hydro Relicensing	SG-P	74,111,750	-	-	74,111,750	-	-	74,111,750	-	-
Hydro Relicensing	SG-P	103,413,085	-	(4,666)	103,408,419	-	(4,666)	103,403,753	-	(4,666)
Hydro Relicensing	SG-U	9,880,613	-	(14,920)	9,865,693	-	(14,920)	9,850,772	-	(14,920)
General Office	SO	449,284,535	1,558,576	(1,123,079)	449,720,031	1,084,730	(1,123,079)	449,681,682	13,728,833	(1,123,079)
Utah	UT	(26,167,651)	-	(561)	(26,168,212)	-	(561)	(26,168,774)	-	(561)
Washington	WA	2,036,986	-	-	2,036,986	-	-	2,036,986	-	-
Eastern Wyoming	WYP	5,599,423	-	(7,729)	5,591,694	-	(7,729)	5,583,966	-	(7,729)
Western Wyoming	WYU	-	-	-	-	-	-	-	-	-
Total Intangible Plant		1,052,130,924	1,558,576	(1,252,606)	1,052,436,894	1,084,730	(1,252,606)	1,052,269,019	13,728,833	(1,252,606)
Total		31,637,227,283	98,865,300	(16,474,521)	31,719,618,062	159,150,667	(16,474,521)	31,862,294,208	128,158,242	(16,474,521)

PacifiCorp
Oregon General Rate Case - December 2023
Pro Forma Plant Additions
and Retirements

Description	Factor	Adjusted EPIS Balance Jun 2022	Capital Additions	Retirements	Adjusted EPIS Balance Jul 2022	Capital Additions	Retirements	Adjusted EPIS Balance Aug 2022	Capital Additions	Retirements
Steam Production Plant:										
Pre-merger Pacific	SG	1,007,547,821	-	(411,968)	1,007,135,853	-	(411,968)	1,006,723,885	-	(411,968)
Pre-merger Utah	SG	1,052,711,867	-	(538,554)	1,052,173,312	-	(538,554)	1,051,634,758	-	(538,554)
Post-merger	SG	4,850,117,378	5,909,808	(3,118,406)	4,852,908,780	(303,139)	(3,118,406)	4,849,487,236	123,052	(3,118,406)
Geothermal - Blundell	SG	29,402,029	-	-	29,402,029	-	-	29,402,029	-	-
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-
Post-merger - Cholla	SG	1,266,851	-	-	1,266,851	-	-	1,266,851	-	-
Total Steam Plant		6,941,045,946	5,909,808	(4,068,928)	6,942,886,826	(303,139)	(4,068,928)	6,938,514,759	123,052	(4,068,928)
Hydro Production Plant:										
Pre-merger Pacific	SG	183,221,776	-	(50,121)	183,171,656	-	(50,121)	183,121,535	-	(50,121)
Pre-merger Utah	SG	39,470,725	-	(32,867)	39,437,858	-	(32,867)	39,404,991	-	(32,867)
Post-merger	SG-P	685,422,405	382,356	(183,427)	685,621,333	7,223,889	(183,427)	692,661,794	371,360	(183,427)
Post-merger	SG-U	161,457,546	1,162,945	(37,209)	162,583,282	(64,385)	(37,209)	162,481,687	(64,385)	(37,209)
Klamath - New Capital	SG-P	4,171,133	-	-	4,171,133	-	-	4,171,133	-	-
Klamath	SG-P	91,504,591	-	-	91,504,591	-	-	91,504,591	-	-
Total Hydro Plant		1,165,248,176	1,545,301	(303,624)	1,166,489,852	7,159,503	(303,624)	1,173,345,731	306,975	(303,624)
Other Production Plant:										
Pre-merger Utah	SG	235,129	-	-	235,129	-	-	235,129	-	-
Post-merger	SG	1,958,550,147	222,194	(2,040,058)	1,956,732,283	(17,642)	(2,040,058)	1,954,674,583	(17,642)	(2,040,058)
Post-merger Wind	SG-W	3,240,357,392	1,241,001	(238,555)	3,241,359,838	1,241,001	(238,555)	3,242,362,283	1,241,001	(238,555)
Black Cap Solar	OR	360,189	5,019	-	365,207	5,019	-	370,226	5,019	-
Post-merger	SG	89,778,232	4,057	(46,204)	89,736,085	4,057	(46,204)	89,693,938	4,057	(46,204)
Total Other Plant		5,289,281,089	1,472,271	(2,324,817)	5,288,428,542	1,232,435	(2,324,817)	5,287,336,160	1,232,435	(2,324,817)
Transmission Plant:										
Pre-merger Pacific	SG	477,783,329	-	(168,182)	477,615,146	-	(168,182)	477,446,964	-	(168,182)
Pre-merger Utah	SG	617,127,958	-	(295,470)	616,832,489	-	(295,470)	616,537,019	-	(295,470)
Post-merger	SG	6,764,681,518	39,318,077	(726,705)	6,803,272,890	16,541,889	(726,705)	6,819,088,074	16,819,653	(726,705)
Total Transmission Plant		7,859,592,805	39,318,077	(1,190,357)	7,897,720,525	16,541,889	(1,190,357)	7,913,072,057	16,819,653	(1,190,357)
Distribution Plant:										
California	CA	325,357,002	5,098,095	(145,707)	330,309,390	883,260	(145,707)	331,046,942	969,518	(145,707)
Oregon	OR	2,431,380,183	12,301,614	(1,763,593)	2,441,918,204	7,591,643	(1,763,593)	2,447,746,254	11,803,387	(1,763,593)
Washington	WA	590,028,062	19,873,165	(198,825)	609,702,402	1,837,494	(198,825)	611,341,070	1,242,842	(198,825)
Eastern Wyoming	WYP	704,897,274	2,076,540	(271,721)	706,702,093	2,366,401	(271,721)	708,796,773	2,182,224	(271,721)
Utah	UT	3,557,792,964	18,233,410	(1,414,241)	3,574,612,134	16,641,242	(1,414,241)	3,589,839,134	15,745,098	(1,414,241)
Idaho	ID	429,549,241	2,174,813	(155,146)	431,568,909	2,182,875	(155,146)	433,596,638	2,906,244	(155,146)
Western Wyoming	WYU	154,717,568	-	(27,785)	154,689,783	-	(27,785)	154,661,999	-	(27,785)
Total Distribution Plant		8,193,722,295	59,757,637	(3,977,018)	8,249,502,914	31,502,914	(3,977,018)	8,277,028,811	34,849,313	(3,977,018)

PacifiCorp
Oregon General Rate Case - December 2023
Pro Forma Plant Additions
and Retirements

Description	Factor	Adjusted EPIS Balance Jun 2022	Capital Additions	Retirements	Adjusted EPIS Balance Jul 2022	Capital Additions	Retirements	Adjusted EPIS Balance Aug 2022	Capital Additions	Retirements
General Plant:										
California	CA	23,028,594	117,793	(43,689)	23,102,698	365,857	(43,689)	23,424,866	136,821	(43,689)
Oregon	OR	236,796,644	1,098,838	(323,194)	237,572,288	763,850	(323,194)	238,012,944	1,106,018	(323,194)
Washington	WA	49,023,713	186,183	(115,214)	49,094,682	100,890	(115,214)	49,080,358	380,123	(115,214)
Eastern Wyoming	WYP	90,342,257	349,396	(254,299)	90,437,355	758,302	(254,299)	90,941,358	440,710	(254,299)
Utah	UT	264,810,245	2,798,500	(479,305)	267,129,440	1,796,913	(479,305)	268,447,047	2,336,534	(479,305)
Idaho	ID	53,610,977	152,450	(68,917)	53,694,511	219,105	(68,917)	53,844,700	167,053	(68,917)
Western Wyoming	WYU	17,820,467	-	(31,708)	17,788,760	-	(31,708)	17,757,052	-	(31,708)
Pre-merger Pacific	SG	840,308	-	(13,917)	826,391	-	(13,917)	812,474	-	(13,917)
Pre-merger Utah	SG	2,452,655	-	(30,778)	2,421,877	-	(30,778)	2,391,098	-	(30,778)
Post-merger	SG	305,008,570	307,257	(578,398)	304,737,429	298,382	(578,398)	304,457,412	645,034	(578,398)
General Office	SO	395,319,434	1,667,125	(1,303,426)	395,683,133	1,131,538	(1,303,426)	395,511,244	1,941,818	(1,303,426)
General Office	SG	-	-	-	-	-	-	-	-	-
General Office	SG	223,232	-	-	223,232	-	-	223,232	-	-
Customer Service	CN	16,102,447	-	(99,428)	16,003,019	-	(99,428)	15,903,591	-	(99,428)
Fuel Related	SE	3,139,927	-	(14,898)	3,125,029	-	(14,898)	3,110,131	-	(14,898)
Total General Plant		1,458,519,471	6,677,543	(3,357,172)	1,461,839,842	5,434,837	(3,357,172)	1,463,917,508	7,154,111	(3,357,172)
Mining Plant:										
Coal Mine	SE	1,822,901	-	-	1,822,901	-	-	1,822,901	-	-
Total Mining Plant		1,822,901	-	-	1,822,901	-	-	1,822,901	-	-
Intangible Plant:										
California	CA	481,167	-	-	481,167	-	-	481,167	-	-
Customer Service	CN	213,838,449	-	(34,194)	213,804,255	-	(34,194)	213,770,061	-	(34,194)
Pre-merger Utah	SG	477,596	-	-	477,596	-	-	477,596	-	-
Pre-merger Pacific	SG	-	-	-	-	-	-	-	-	-
Idaho	ID	4,370,110	-	(86)	4,370,024	-	(86)	4,369,938	-	(86)
Oregon	OR	4,611,642	-	(363)	4,611,279	-	(363)	4,610,916	-	(363)
Fuel Related	SE	(39,847)	-	(4,079)	(43,926)	-	(4,079)	(48,006)	-	(4,079)
Post-merger	SG	209,928,115	-	(62,928)	209,865,187	-	(62,928)	209,802,260	-	(62,928)
Klamath Hydro Relicensing	SG-P	74,111,750	-	-	74,111,750	-	-	74,111,750	-	-
Hydro Relicensing	SG-P	103,399,088	-	(4,666)	103,394,422	-	(4,666)	103,389,757	-	(4,666)
Hydro Relicensing	SG-U	9,835,852	-	(14,920)	9,820,931	-	(14,920)	9,806,011	-	(14,920)
General Office	SO	462,287,436	802,300	(1,123,079)	461,966,656	739,350	(1,123,079)	461,582,927	4,718,441	(1,123,079)
Utah	UT	(26,169,335)	-	(561)	(26,169,897)	-	(561)	(26,170,458)	-	(561)
Washington	WA	2,036,986	-	-	2,036,986	-	-	2,036,986	-	-
Eastern Wyoming	WYP	5,576,237	-	(7,729)	5,568,509	-	(7,729)	5,560,780	-	(7,729)
Western Wyoming	WYU	-	-	-	-	-	-	-	-	-
Total Intangible Plant		1,064,745,246	802,300	(1,252,606)	1,064,294,941	739,350	(1,252,606)	1,063,781,685	4,718,441	(1,252,606)
Total		31,973,977,929	115,482,937	(16,474,521)	32,072,986,344	62,307,789	(16,474,521)	32,118,819,612	65,203,980	(16,474,521)

PacifiCorp
Oregon General Rate Case - December 2023
Pro Forma Plant Additions
and Retirements

Description	Factor	Adjusted EPIS Balance Sep 2022	Capital Additions	Retirements	Adjusted EPIS Balance Oct 2022	Capital Additions	Retirements	Adjusted EPIS Balance Nov 2022	Capital Additions	Retirements
Steam Production Plant:										
Pre-merger Pacific	SG	1,006,311,917	-	(411,968)	1,005,899,948	-	(411,968)	1,005,487,980	-	(411,968)
Pre-merger Utah	SG	1,051,096,204	-	(538,554)	1,050,557,650	-	(538,554)	1,050,019,095	-	(538,554)
Post-merger	SG	4,846,491,883	4,107,487	(3,118,406)	4,847,480,964	7,789,652	(3,118,406)	4,852,152,210	15,967,861	(3,118,406)
Geothermal - Blundell	SG	29,402,029	-	-	29,402,029	-	-	29,402,029	-	-
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-
Post-merger - Cholla	SG	1,266,851	-	-	1,266,851	-	-	1,266,851	-	-
Total Steam Plant		6,934,568,884	4,107,487	(4,068,928)	6,934,607,442	7,789,652	(4,068,928)	6,938,328,166	15,967,861	(4,068,928)
Hydro Production Plant:										
Pre-merger Pacific	SG	183,071,414	-	(50,121)	183,021,293	-	(50,121)	182,971,172	-	(50,121)
Pre-merger Utah	SG	39,372,124	-	(32,867)	39,339,257	-	(32,867)	39,306,390	-	(32,867)
Post-merger	SG-P	692,849,727	1,594,764	(183,427)	694,261,064	5,297,767	(183,427)	699,375,404	27,913,365	(183,427)
Post-merger	SG-U	162,380,093	3,433,801	(37,209)	165,776,684	(15,698)	(37,209)	165,723,777	17,600,024	(37,209)
Klamath - New Capital	SG-P	4,171,133	-	-	4,171,133	3,493,814	-	7,664,947	1,982,716	-
Klamath	SG-P	91,504,591	-	-	91,504,591	-	-	91,504,591	-	-
Total Hydro Plant		1,173,349,082	5,028,565	(303,624)	1,178,074,023	8,775,883	(303,624)	1,186,546,282	47,496,104	(303,624)
Other Production Plant:										
Pre-merger Utah	SG	235,129	-	-	235,129	-	-	235,129	-	-
Post-merger	SG	1,952,616,883	2,797,495	(2,040,058)	1,953,374,320	(17,642)	(2,040,058)	1,951,316,621	6,850,016	(2,040,058)
Post-merger Wind	SG-W	3,243,364,729	1,241,001	(238,555)	3,244,367,175	1,241,001	(238,555)	3,245,369,621	1,241,001	(238,555)
Black Cap Solar	OR	375,245	5,019	-	380,264	5,019	-	385,282	5,019	-
Post-merger	SG	89,651,791	4,057	(46,204)	89,609,644	4,057	(46,204)	89,567,497	66,643	(46,204)
Total Other Plant		5,286,243,778	4,047,572	(2,324,817)	5,287,966,533	1,232,435	(2,324,817)	5,286,874,150	8,162,679	(2,324,817)
Transmission Plant:										
Pre-merger Pacific	SG	477,278,782	-	(168,182)	477,110,600	-	(168,182)	476,942,418	-	(168,182)
Pre-merger Utah	SG	616,241,549	-	(295,470)	615,946,080	-	(295,470)	615,650,610	-	(295,470)
Post-merger	SG	6,835,181,021	31,397,739	(726,705)	6,865,852,054	41,961,513	(726,705)	6,907,086,862	45,595,977	(726,705)
Total Transmission Plant		7,928,701,352	31,397,739	(1,190,357)	7,958,908,734	41,961,513	(1,190,357)	7,999,679,890	45,595,977	(1,190,357)
Distribution Plant:										
California	CA	331,870,753	2,186,679	(145,707)	333,911,724	1,818,654	(145,707)	335,584,670	6,759,818	(145,707)
Oregon	OR	2,457,786,048	7,523,232	(1,763,593)	2,463,545,688	6,128,702	(1,763,593)	2,467,910,797	18,180,922	(1,763,593)
Washington	WA	612,385,087	1,486,512	(198,825)	613,672,774	1,323,512	(198,825)	614,797,460	4,812,800	(198,825)
Eastern Wyoming	WYP	710,707,276	1,978,437	(271,721)	712,413,993	1,830,723	(271,721)	713,972,995	2,309,427	(271,721)
Utah	UT	3,604,169,991	23,423,617	(1,414,241)	3,626,179,367	26,789,820	(1,414,241)	3,651,554,946	21,186,314	(1,414,241)
Idaho	ID	436,347,737	2,227,970	(155,146)	438,420,561	1,954,840	(155,146)	440,220,256	4,278,631	(155,146)
Western Wyoming	WYU	154,634,214	-	(27,785)	154,606,429	-	(27,785)	154,578,645	-	(27,785)
Total Distribution Plant		8,307,901,106	38,826,448	(3,977,018)	8,342,750,536	39,846,251	(3,977,018)	8,378,619,770	57,527,912	(3,977,018)

PacifiCorp
Oregon General Rate Case - December 2023
Pro Forma Plant Additions
and Retirements

Description	Factor	Adjusted EPIS Balance Sep 2022	Capital Additions	Retirements	Adjusted EPIS Balance Oct 2022	Capital Additions	Retirements	Adjusted EPIS Balance Nov 2022	Capital Additions	Retirements
General Plant:										
California	CA	23,517,998	109,665	(43,689)	23,583,975	90,292	(43,689)	23,630,578	373,498	(43,689)
Oregon	OR	238,795,768	1,003,203	(323,194)	239,475,776	1,482,161	(323,194)	240,634,743	3,874,044	(323,194)
Washington	WA	49,345,267	122,681	(115,214)	49,352,734	90,771	(115,214)	49,328,290	449,890	(115,214)
Eastern Wyoming	WYP	91,127,770	554,524	(254,299)	91,427,995	1,117,617	(254,299)	92,291,313	1,418,787	(254,299)
Utah	UT	270,304,276	2,332,590	(479,305)	272,157,560	2,089,994	(479,305)	273,768,249	4,451,347	(479,305)
Idaho	ID	53,942,836	219,365	(68,917)	54,093,284	286,015	(68,917)	54,310,382	643,626	(68,917)
Western Wyoming	WYU	17,725,345	-	(31,708)	17,693,637	-	(31,708)	17,661,930	-	(31,708)
Pre-merger Pacific	SG	798,556	-	(13,917)	784,639	-	(13,917)	770,722	-	(13,917)
Pre-merger Utah	SG	2,360,320	-	(30,778)	2,329,541	-	(30,778)	2,298,763	-	(30,778)
Post-merger	SG	304,524,048	796,661	(578,398)	304,742,310	1,921,945	(578,398)	306,085,857	6,185,528	(578,398)
General Office	SO	396,149,636	4,730,508	(1,303,426)	399,576,717	1,540,371	(1,303,426)	399,813,661	8,214,484	(1,303,426)
General Office	SG	-	-	-	-	-	-	-	-	-
General Office	SG	223,232	-	-	223,232	-	-	223,232	-	-
Customer Service	CN	15,804,162	-	(99,428)	15,704,734	-	(99,428)	15,605,305	-	(99,428)
Fuel Related	SE	3,095,234	-	(14,898)	3,080,336	-	(14,898)	3,065,439	-	(14,898)
Total General Plant		1,467,714,447	9,869,196	(3,357,172)	1,474,226,471	8,619,164	(3,357,172)	1,479,488,463	25,611,205	(3,357,172)
Mining Plant:										
Coal Mine	SE	1,822,901	-	-	1,822,901	-	-	1,822,901	-	-
Total Mining Plant		1,822,901	-	-	1,822,901	-	-	1,822,901	-	-
Intangible Plant:										
California	CA	481,167	-	-	481,167	-	-	481,167	-	-
Customer Service	CN	213,735,868	-	(34,194)	213,701,674	-	(34,194)	213,667,480	-	(34,194)
Pre-merger Utah	SG	477,596	-	-	477,596	-	-	477,596	-	-
Pre-merger Pacific	SG	-	-	-	-	-	-	-	-	-
Idaho	ID	4,369,851	-	(86)	4,369,765	-	(86)	4,369,679	-	(86)
Oregon	OR	4,610,553	-	(363)	4,610,189	-	(363)	4,609,826	-	(363)
Fuel Related	SE	(52,085)	-	(4,079)	(56,164)	-	(4,079)	(60,244)	-	(4,079)
Post-merger	SG	209,739,332	-	(62,928)	209,676,404	-	(62,928)	209,613,477	-	(62,928)
Klamath Hydro Relicensing	SG-P	74,111,750	-	-	74,111,750	-	-	74,111,750	-	-
Hydro Relicensing	SG-P	103,385,091	-	(4,666)	103,380,425	-	(4,666)	103,375,760	-	(4,666)
Hydro Relicensing	SG-U	9,791,091	-	(14,920)	9,776,170	-	(14,920)	9,761,250	-	(14,920)
General Office	SO	465,178,289	647,880	(1,123,079)	464,703,089	2,532,110	(1,123,079)	466,112,120	11,799,593	(1,123,079)
Utah	UT	(26,171,019)	-	(561)	(26,171,581)	-	(561)	(26,172,142)	-	(561)
Washington	WA	2,036,986	-	-	2,036,986	-	-	2,036,986	-	-
Eastern Wyoming	WYP	5,553,052	-	(7,729)	5,545,323	-	(7,729)	5,537,594	-	(7,729)
Western Wyoming	WYU	-	-	-	-	-	-	-	-	-
Total Intangible Plant		1,067,247,521	647,880	(1,252,606)	1,066,642,795	2,532,110	(1,252,606)	1,067,922,300	11,799,593	(1,252,606)
Total		32,167,549,070	93,924,886	(16,474,521)	32,244,999,434	110,757,008	(16,474,521)	32,339,281,921	212,161,332	(16,474,521)

PacifiCorp
Oregon General Rate Case - December 2023
Pro Forma Plant Additions
and Retirements

Description	Factor	Adjusted EPIS Balance Dec 2022	End of Period December 2022 Test Period Balance
Steam Production Plant:			
Pre-merger Pacific	SG	1,005,076,012	1,005,076,012
Pre-merger Utah	SG	1,049,480,541	1,049,480,541
Post-merger	SG	4,865,001,665	4,865,001,665
Geothermal - Blundell	SG	29,402,029	29,402,029
Pollution Control Equipment	SG	-	-
Pollution Control Equipment	SG	-	-
Pollution Control Equipment	SG	-	-
Post-merger - Cholla	SG	1,266,851	1,266,851
Total Steam Plant		6,950,227,099	6,950,227,099
Hydro Production Plant:			
Pre-merger Pacific	SG	182,921,052	182,921,052
Pre-merger Utah	SG	39,273,524	39,273,524
Post-merger	SG-P	727,105,341	727,105,341
Post-merger	SG-U	183,286,592	183,286,592
Klamath - New Capital	SG-P	9,647,664	9,647,664
Klamath	SG-P	91,504,591	91,504,591
Total Hydro Plant		1,233,738,762	1,233,738,762
Other Production Plant:			
Pre-merger Utah	SG	235,129	235,129
Post-merger	SG	1,956,126,579	1,956,126,579
Post-merger Wind	SG-W	3,246,372,067	3,246,372,067
Black Cap Solar	OR	390,301	390,301
Post-merger	SG	89,587,935	89,587,935
Total Other Plant		5,292,712,012	5,292,712,012
Transmission Plant:			
Pre-merger Pacific	SG	476,774,235	476,774,235
Pre-merger Utah	SG	615,355,140	615,355,140
Post-merger	SG	6,951,956,134	6,951,956,134
Total Transmission Plant		8,044,085,510	8,044,085,510
Distribution Plant:			
California	CA	342,198,781	342,198,781
Oregon	OR	2,484,328,127	2,484,328,127
Washington	WA	619,411,435	619,411,435
Eastern Wyoming	WYP	716,010,701	716,010,701
Utah	UT	3,671,327,019	3,671,327,019
Idaho	ID	444,343,741	444,343,741
Western Wyoming	WYU	154,550,860	154,550,860
Total Distribution Plant		8,432,170,664	8,432,170,664

PacifiCorp
Oregon General Rate Case - December 2023
Pro Forma Plant Additions
and Retirements

Description	Factor	Adjusted EPIS Balance Dec 2022	End of Period December 2022 Test Period Balance
General Plant:			
California	CA	23,960,387	23,960,387
Oregon	OR	244,185,593	244,185,593
Washington	WA	49,662,967	49,662,967
Eastern Wyoming	WYP	93,455,801	93,455,801
Utah	UT	277,740,291	277,740,291
Idaho	ID	54,885,092	54,885,092
Western Wyoming	WYU	17,630,222	17,630,222
Pre-merger Pacific	SG	756,805	756,805
Pre-merger Utah	SG	2,267,985	2,267,985
Post-merger	SG	311,692,986	311,692,986
General Office	SO	406,724,719	406,724,719
General Office	SG	-	-
General Office	SG	223,232	223,232
Customer Service	CN	15,505,877	15,505,877
Fuel Related	SE	3,050,541	3,050,541
Total General Plant		1,501,742,497	1,501,742,497
Mining Plant:			
Coal Mine	SE	1,822,901	1,822,901
Total Mining Plant		1,822,901	1,822,901
Intangible Plant:			
California	CA	481,167	481,167
Customer Service	CN	213,633,287	213,633,287
Pre-merger Utah	SG	477,596	477,596
Pre-merger Pacific	SG	-	-
Idaho	ID	4,369,593	4,369,593
Oregon	OR	4,609,463	4,609,463
Fuel Related	SE	(64,323)	(64,323)
Post-merger	SG	209,550,549	209,550,549
Klamath Hydro Relicensing	SG-P	74,111,750	74,111,750
Hydro Relicensing	SG-P	103,371,094	103,371,094
Hydro Relicensing	SG-U	9,746,329	9,746,329
General Office	SO	476,788,634	476,788,634
Utah	UT	(26,172,704)	(26,172,704)
Washington	WA	2,036,986	2,036,986
Eastern Wyoming	WYP	5,529,866	5,529,866
Western Wyoming	WYU	-	-
Total Intangible Plant		1,078,469,287	1,078,469,287
Total		32,534,968,731	32,534,968,731
			Ref. 8.5.4

PacifiCorp
Oregon General Rate Case - December 2023
Pro Forma Plant Additions
Steam Plant Additions

Project Description	FERC Account	Factor	Inservice Date	July21 to Dec22 Plant Adds	Ref.
U0 Huntington Water Redirect; U0 Land Application Conversion D	312	SG	Oct-21	12,627,976	**8.4.28**
Wyodak U1 - Boiler Waterwall Replacement CY21/CY22	312	SG	May-22	3,871,573	
Colstrip 3-4: Design/Build Dry Waste	312	SG	Jul-22	3,755,217	
Hunter 301 HP/IP/LP Turbine Overhaul	312	SG	Apr-22	3,368,292	
Dave Johnston U4 - Retube Condenser	312	SG	May-22	3,196,216	
Wyodak U1 - Replacement of Turbine HP Rotor CY2	312	SG	May-22	3,098,322	
Naughton U1 OH Turbine Major (HP/IP/LP) CY22	312	SG	May-22	3,093,440	
Wyodak U1 - HP/IP Turbine Overhaul CY22	312	SG	May-22	2,844,080	
Hunter 301 Replace Scrubber Outlet Header Duct	312	SG	Apr-22	2,798,490	
Huntington U1 Boiler Rear Reheat Header & Terminal Tubes	312	SG	Oct-22	2,754,488	
Wyodak U1 - Expansion Joint Replace CY21/CY22	312	SG	Apr-22	2,053,232	
Hunter 301 Scrubber Component Overhaul	312	SG	Apr-22	1,929,947	
Gadsby U2 Cooling Tower Replacement	312	SG	May-22	1,896,045	
Hunter 301 Generator Exciter Rewind	312	SG	Apr-22	1,632,781	
Dave Johnston U0 - MILL BLANKET - 2022	312	SG	Various	1,625,476	
Naughton U1 OH Mechanical Dust Collectors CY20	312	SG	May-22	1,621,240	
Hunter 301 SH Division Panel Replacements	312	SG	Apr-22	1,526,203	
Jim Bridger U2 Burners Major 22	312	SG	Jun-22	1,490,848	
Huntington U1 Burner Corner Coal Nozzle & Tip replacement	312	SG	Nov-22	1,483,079	
Dave Johnston U0 - PUMPS AND VALVES - 2022	312	SG	Various	1,395,788	
Huntington U1 LP Turbine Component Replacement	312	SG	Nov-22	1,329,919	
Hunter 301 Burner Tips and Nozzles	312	SG	Apr-22	1,087,793	
Dave Johnston U0 - MILL BLANKET - 2021	312	SG	Various	1,077,176	
Wyodak U1 - Pulverizer Overhaul "B" CY22	312	SG	May-22	1,037,950	
Projects Less Than $1million	312	SG	Various	102,876,042	
Projects Less Than $1million - Cholla	312	SSGCH	Various	-	
Steam Plant Five Year Average Removals	312	SG		(26,028,982)	
				139,442,631	

PacifiCorp
Oregon General Rate Case - December 2023
Pro Forma Plant Additions
Hydro Plant Additions

Project Description	FERC Account	Factor	Inservice Date	July21 to Dec22 Plant Adds	Ref.
PP Hydro West	332	SG-P	Various	17,546,469	
Merwin Downstream In-Lieu	332	SG-P	Dec-22	14,144,756	**8.4.28**
PP Hydro East	332	SG-U	Various	10,267,241	
ILR 4.1.9 Future Fish Passage Stage 1 Ph	332	SG-P	Jun-22	9,478,781	
Yale Saddle Dam Seismic Remediation	332	SG-P	Various	7,452,707	
PP Hydro Impl On-Proj West	332	SG-P	Various	7,034,218	
Toketee Dam Rehabilitation	332	SG-P	Dec-21	5,417,562	
Cutler Surge Tank Anchor Upgrades	332	SG-U	Dec-22	4,979,273	
Soda Spinning Reserve	332	SG-U	Dec-22	4,368,628	
Toketee 2 Turbine Refurbishment	332	SG-P	Dec-22	3,515,432	
Iron Gate Bridge K6 Life Extension	332	SG-P	Nov-22	3,453,066	
PP Hydro Plant JA	332	SG-P	Various	3,341,354	
PP Other Hydro Dam Safety West	332	SG-P	Various	2,811,412	
PP Other Hydro Dam Safety JA	332	SG-P	Various	2,186,344	
Cutler Surge Tank Anchor Upgrades	332	SG-U	Dec-21	2,026,064	
Iron Gate CSIR Mandated Improvements 2020	332	SG-P	Dec-22	1,955,135	
ILR 11.2.2.12 Beaver Bay PH 1 Renovation	332	SG-P	Dec-22	1,782,000	
Cutler Flowline Coating Replacement 2021	332	SG-U	Dec-21	1,675,693	
Ashton Trash Rake Construction	332	SG-U	Dec-22	1,620,000	
Oneida Switchgear	332	SG-U	Oct-22	1,593,921	
SWIFT 1 SPARE GSU REPLACEMENT	332	SG-P	Feb-22	1,458,000	
Toketee Flowline Isolation Valve	332	SG-P	Oct-21	1,368,918	
Bigfork Fish Screen Rake	332	SG-U	Jul-22	1,227,330	
Weber Dam Improvements Evaluation	332	SG-U	Dec-22	1,178,220	
PP Other Hydro Dam Safety East	332	SG-U	Various	1,140,601	
Merwin 2 Intake Screen Replacement	332	SG-P	Dec-21	1,051,113	
Prospect North Fork Trash Rack Improvement	332	SG-P	Feb-22	1,010,917	
Projects Less Than $1million	332	SG-P	Various	3,976,099	
Projects Less Than $1million	332	SG-U	Various	2,141,705	
Hydro Plant Five Year Average Removals	332	SG-U		(1,158,934)	
Hydro Plant Five Year Average Removals	332	SG-P		(1,596,134)	
				118,447,892	

PacifiCorp
Oregon General Rate Case - December 2023
Pro Forma Plant Additions
Other Plant Additions

Project Description	FERC Account	Factor	Inservice Date	July21 to Dec22 Plant Adds	Ref.
TB Flats Wind Project 500 MW 2020	343	SG-W	Various	54,196,091	**8.4.28**
Currant Creek U2 CSA Variable Fee 32k - CTB MI	343	SG	Oct-21	12,742,259	**8.4.28**
Currant Creek U1 CSA Variable Fee 32k - CTA MI	343	SG	Oct-21	12,734,888	**8.4.29**
Chehalis U1 CSA Variable fee - CT1 - HGP	343	SG	Apr-22	11,723,088	**8.4.29**
Chehalis U2 CSA Variable fee - CT2 - HGP	343	SG	Apr-22	11,693,774	**8.4.29**
Pryor Mtn Wind Project 240 MW 2020	343	SG-W	Various	11,120,326	**8.4.29**
PP Wind Production	343	SG-W	Various	6,891,562	
Foote Creek Repowering	343	SG-W	Various	5,533,249	
Hermiston U2 Overhaul Capital CY23 MI	343	SG	Dec-22	4,670,914	
Hermiston U0 Capital Spares 12K Parts	343	SG	Oct-22	2,321,337	
PP Eagle Mitigation	343	SG-W	Various	2,136,539	
Gadsby U6 Stage 1 HPT blade replacement 191-364	343	SG	Sep-21	1,464,254	
Gadsby U6 Stage 2 HPT blade replacement 191-364	343	SG	Jul-21	1,310,335	
Chehalis U3 RT Lite Valve Replacement	343	SG	May-22	1,050,959	
Projects Less Than $1million	343	SG	Various	11,707,167	
Projects Less Than $1million	343	SG-W	Various	11,344,707	
Projects Less Than $1million - Situs OR	343	OR	Various	315,315	
Projects Less Than $1million - Seasonal SSGCT	343	SG	Various	2,004,803	
Other Plant Five Year Average Removals	343	SG		(1,766,276)	
Other Plant - Wind Five Year Average Removals	343	SG		(1,352,633)	
				161,842,657	

PacifiCorp
Oregon General Rate Case - December 2023
Pro Forma Plant Additions
Transmission Plant Additions

Project Description	FERC Account	Factor	Inservice Date	July21 to Dec22 Plant Adds	Ref.
Pacific Power Transmission Replacements	355	SG	various	29,346,318	
Transmission Customer New Revenue East	355	SG	Various	24,921,999	
Goshen-Sugarmill-Rigby 161kV Trans Line- Trans	355	SG	Jul-22	23,237,498	**8.4.29**
Jordanelle - Midway Construct 138 kV Line - Trans	355	SG	Dec-21	21,938,510	**8.4.30**
Rocky Mountain Power 2021 Trans Investment Programs	355	SG	Various	19,712,244	
Klamath Falls - Snow Goose 230 kV Line No. 2 TPL	355	SG	Nov-22	17,335,128	**8.4.30**
Utah Transmission BLM & Other ROW Renewals	355	SG	Various	16,658,532	
Rexburg Sub - Inst 161kV Source from Rigby	355	SG	Nov-21	16,521,644	**8.4.30**
Pacific Power Transmission Wildfire Mitigation Projects	355	SG	various	14,942,038	**8.4.30**
Pacific Power Sub-Trans/Major Sub System Upgrades	355	SG	Various	14,383,367	
Rocky Mountain Power Transmission Wildfire Mitigation	355	SG	Various	13,607,812	**8.4.31**
Transmission Customer New Revenue West	355	SG	Various	13,038,073	
Jim Bridger 345-230 kV Transformer 2 Upgrade	355	SG	Oct-21	13,013,486	**8.4.31**
Transmission Customer System Upgrade East	355	SG	Various	12,785,002	
Transmission Main Grid System Upgrades East	355	SG	Various	9,317,726	
Jordan Valley - Commercial Load	355	SG	Dec-21	7,764,347	
Magna Cap and Tooele - Pine Cyn Rebuild 138kV	355	SG	Dec-22	6,016,322	
Transmission Main Grid System West	355	SG	Various	5,595,414	
Bear River 138kV Conversion	355	SG	Dec-22	5,323,100	
Tucker 69 kV Tie Line	355	SG	Nov-22	5,174,101	
Utah Transmission Replace Sub Switchgear, Breakers, Reclosers	355	SG	Various	5,157,710	
Flint New 115kV to 12.5kV Substation Project- Trans	355	SG	Apr-22	5,152,491	
Lebanon Loop Reliability Upgrade Project (Weirich) Phase 1	355	SG	Sep-21	4,999,751	
Goshen #3 35/161 kV 400 MVA Transformer Install TPL	355	SG	Aug-22	4,800,894	
Utah Transmission Replace - Storm & Casualty	355	SG	Various	4,599,668	
Line 39 Reconductor	355	SG	Sep-21	4,552,011	
Douglas - Construct 115kV Line	355	SG	Sep-22	4,481,073	
St Johns (BPA) to Knott 115kV Line Conversion Project	355	SG	Oct-22	4,171,780	
Utah Replace Overhead Transmission Poles	355	SG	Various	3,849,292	
RMP Grid Resilience Replacement 345-138kV 700MVA XFMR	355	SG	Dec-21	3,809,892	
Huntington U0 Universal Spare GSU Huntington Plant	355	SG	Nov-22	3,418,537	
Cross Hollows Install 2nd Xfmr - Trans	355	SG	May-22	3,373,396	
Klamath Falls -Hornet 69 kv line 9, Reconductor 5.3 miles T	355	SG	Sep-22	3,053,014	
Reroute JB Goshen 345kV line for Slide: IPC Shared	355	SG	Oct-22	2,926,466	
Hunter 301 Spare Main GSU Replacement	355	SG	Oct-22	2,814,940	
Outlook Sub Rpl Transf 321065 (T2134)	355	SG	Dec-21	2,802,256	
BLM Sigurd-Glen Canyon	355	SG	Jul-22	2,761,639	
Nickel Mtn Sub: Replace TRF3512(324647)	355	SG	Dec-21	2,705,966	
Utah Transmission SF6 - Circuit Breaker Replacements	355	SG	Various	2,431,375	
115 kV Tillamook-Astoria Insp & Repl Suspension Insul	355	SG	Dec-22	2,394,879	
Pacific Power Spare Transmission 230-69kV Transformer Purchase	355	SG	Sep-21	2,360,613	
Utah Transmission CAPEX Condition Correction	355	SG	Various	2,278,002	
Vantage - Pomona Heights - TPL002	355	SG	Various	2,246,043	
Wyoming Replace Transmission Conductor/Armor Rod	355	SG	Various	2,230,361	
RMP Replace 345-230kV 450 MVA XFMR	355	SG	Sep-22	2,184,728	
RMP Storage Yard Site Development	355	SG	Dec-21	2,150,991	
Populus - Terminal 345 kV line - condemnation settlements	355	SG	Various	2,109,518	
Wyoming Replace Overhead Transmission Poles	355	SG	Various	2,025,943	
Utah Transmission Line Improvements - Other	355	SG	Various	1,772,357	
Pacific Power Transmission New Connects	355	SG	various	1,731,815	
Pacific Power Spare Transmission 115-69kV Transformer Purchase	355	SG	Oct-21	1,713,625	
Utah Transmission Replace Substation Transformers	355	SG	Various	1,624,527	
Wyoming Transmission BLM & Other ROW Renewals	355	SG	Various	1,582,146	
BLM Helper-Moab	355	SG	Dec-22	1,556,706	
Taylorsville-Granger East Tap 46 kV line Rebuild	355	SG	May-22	1,553,292	
Utah Transmission Replace Sub Bushings, Glass & Other	355	SG	Various	1,520,478	
Pacific Power Transmission Line Reliability Linescope projects	355	SG	Oct-21	1,484,798	
Alturas Replace 115-69kV Transformer Bank	355	SG	Dec-22	1,400,000	
Price City Tap to Helper Rebuild	355	SG	Dec-21	1,390,603	
Aeolus-Bridger/Anticline 500 kV Line	355	SG	Various	1,354,411	
Idaho Transmission Replace - Storm & Casualty	355	SG	Various	1,272,931	
Idaho Replace Overhead Transmission Lines - Other	355	SG	Various	1,267,250	
Idaho Power 2021 Emergent Capital Work	355	SG	Various	1,121,107	
Southeast - Install New Control Building	355	SG	Dec-21	1,028,614	
Idaho Power - Borah - Midpoint #1 replace wood w/ steel	355	SG	Various	1,027,822	
Idaho Replace Overhead Transmission Poles	355	SG	Various	1,012,972	
Utah Transmission Protection Improvements	355	SG	Various	1,012,529	
Projects Less Than $1million	355	SG	Various	19,529,764	
Transmission Five Year Average Removals	355	SG		(9,073,889)	
				419,359,745	

PacifiCorp
Oregon General Rate Case - December 2023
Pro Forma Plant Additions
Distribution Plant Additions

Project Description	FERC Account	Factor	Inservice Date	July21 to Dec22 Plant Adds	Ref.
PP Distribution OR	364	OR	various	81,479,359	
PP Dist New Connect OR	364	OR	various	72,121,946	
AMI - Utah Meters 2019 -2020	364	UT	Dec-22	44,696,839	
Wildfire Mitigation - Dist	364	UT	Various	41,146,176	
Utah-New Connect - Residential	364	UT	Various	36,710,227	
RMPDistUT Investment Programs	364	UT	Various	36,134,794	
Wildfire - Dist - CA	364	CA	various	35,348,247	
RMPDist - NRUT Investment Programs	364	UT	Various	30,876,031	
Wildfire - Dist - OR	364	OR	various	27,237,149	**8.4.31**
Utah-New Connect - Commercial	364	UT	Various	19,993,879	
OR Distribution Major Projects	364	OR	Various	18,464,660	
PP Distribution WA	364	WA	various	18,215,506	
WA Distribution Major Projects	364	WA	Various	16,699,555	
AMI - Idaho 2019 meters	364	ID	Dec-22	14,372,112	
PP Dist New Connect CA	364	CA	various	13,277,942	
PP Dist New Connect WA	364	WA	various	12,469,790	
Rock Springs - Industrial Load	364	WYP	May-22	11,843,859	
U/G Cable Test & Replace	364	UT	Various	11,177,995	
Cedar City - Commercial Load	364	UT	May-22	10,046,845	
Jordan Valley - Install New Substation - Dist	364	UT	Mar-22	9,839,485	
Replace Underground Vaults & Equipment - UT	364	UT	Various	7,676,470	
Replace Overhead Distribution Poles - UT	364	UT	Various	7,649,912	
RMPDistWY Investment Programs	364	WYP	Various	7,606,011	
Wildfire - Dist - WA	364	WA	various	7,296,075	
PP Distribution CA	364	CA	various	6,854,974	
Replace Overhead Distribution Lines - Crossarms & Cutouts - UT Dist	364	UT	Various	6,753,788	
RMPDist - NRWY Investment Programs	364	WYP	Various	6,131,892	
Targeted reliability Improvement, Dist - UT	364	UT	Various	5,544,854	
Jordan Valley - Install 30 MVA Transformer - Dist	364	UT	Jun-22	5,484,788	
Mandated Highway Relocations - UT - D	364	UT	Various	5,294,509	
New Revenue - Feeder Reinforcement - UT	364	UT	Various	5,072,505	
Replace Underground Cable - UT	364	UT	Various	4,999,619	
RMPDistID Investment Programs	364	ID	Various	4,905,674	
American Fork - Install Second Transformer - Dist	364	UT	May-21	4,484,245	
RMPDist - NRID Investment Programs	364	ID	Various	4,284,523	
Replace - Storm & Casualty - UT Dist	364	UT	Various	4,267,437	
Idaho-New Connect - Residential	364	ID	Various	4,093,128	
Cedar City - Install New Dist Sub	364	UT	Dec-22	4,055,073	
Richfield - Industrial Load	364	UT	Dec-21	3,920,547	
Replace Overhead Distribution Lines - Other - UT	364	UT	Various	3,864,679	
UT - Increase Capacity - Dist	364	UT	Dec-22	3,754,346	
Wyoming-New Connect - Residential	364	WYP	Various	3,732,615	
New Connect Meter Purchases - UT	364	UT	Various	3,613,049	
Preston - Substation Transmission Breaker Additions	364	ID	Dec-21	3,287,982	
Jordan Valley - Substation Property Acquisition	364	UT	Jun-22	3,255,780	
CAPEX Condition Correction - Dist - UT	364	UT	Various	3,182,574	
Mobile #6 Replace Failed 138-69kV Transformer	364	UT	Nov-22	3,036,362	
Avian Protection - Dist WY	364	WYP	Various	2,977,553	
Jordan Valley - Commercial Load	364	UT	May-22	2,909,079	
Wildfire Storm Costs Dist OR	364	OR	various	2,657,313	
Metro - Commercial Load	364	UT	May-22	2,652,629	
Replace Overhead Distribution Poles - ID	364	ID	Various	2,642,145	
Replace Overhead Distribution Lines - Crossarms & Cutouts - WY Dist	364	WYP	Various	2,373,454	
Layton - Commercial Load	364	UT	Nov-21	2,370,488	
Wyoming-New Connect - Commercial	364	WYP	Various	2,355,288	
Avian Protection - Dist UT	364	UT	Various	2,172,228	
Replace Underground Cable - WY	364	WYP	Various	2,080,411	
TPU/DPU Relay Replacement Program - UT	364	UT	Various	2,047,493	
Rexburg - Control Building Addition	364	ID	Dec-22	2,035,944	
Metro - Commercial Load	364	UT	Nov-22	2,027,680	
Linerupter Switch Replacement Program	364	ID	Various	1,994,178	
Tiller Sub-Replace Structures and Transformer	364	OR	Dec-21	1,966,419	
Replace Overhead Distribution Poles - WY	364	WYP	Various	1,931,145	

PacifiCorp
Oregon General Rate Case - December 2023
Pro Forma Plant Additions
Distribution Plant Additions

Project Description	FERC Account	Factor	Inservice Date	July21 to Dec22 Plant Adds	Ref.
EX Utah Development, 19.03 MW Load	364	UT	Dec-22	1,929,655	
Avian Protection - Dist ID	364	ID	Various	1,882,696	
Cedar City - Install 2nd Xfmr - Dist	364	UT	May-22	1,722,451	
Madras SC: Buy three 500 & 230 kV GR Spare Ck Bkrs	364	OR	Dec-21	1,629,217	
Replace Substation Transformers - UT - D	364	UT	Various	1,602,445	
Pole Failure Mitigation - Porcelain Cutout Replacement - UT Dist	364	UT	Various	1,561,894	
Replace - Storm & Casualty - WY Dist	364	WYP	Various	1,433,267	
UT - Add Mobile Connection	364	UT	May-22	1,406,818	
Idaho-New Connect - Commercial	364	ID	Various	1,303,554	
Metro - 8kV System Upgrade - Dist	364	UT	Various	1,275,083	
Replace Overhead Distribution Lines - Other - WY	364	WYP	Various	1,169,363	
Metro - Commercial Load	364	UT	Jul-21	1,100,000	
Cedar City - Commercial Load	364	UT	May-22	1,084,448	
Replace - Storm & Casualty - ID Dist	364	ID	Various	1,082,460	
Replace Overhead Distribution Lines - Crossarms & Cutouts - ID Dist	364	ID	Various	1,077,585	
Neutral Extensions - WY	364	WYP	Various	1,022,388	
Metro - Commercial Load	364	UT	Apr-22	1,009,441	
Projects Less Than $1million	364	CA	Various	43,522	
Projects Less Than $1million	364	ID	Various	7,999,823	
Projects Less Than $1million	364	OR	Various	-	
Projects Less Than $1million	364	UT	Various	16,246,926	
Projects Less Than $1million	364	WA	Various	-	
Projects Less Than $1million	364	WYP	Various	8,595,845	
Distribution Plant Five Year Average Removals	364	CA		(1,087,989)	
Distribution Plant Five Year Average Removals	364	ID		(1,704,769)	
Distribution Plant Five Year Average Removals	364	OR		(14,165,176)	
Distribution Plant Five Year Average Removals	364	UT		(15,214,652)	
Distribution Plant Five Year Average Removals	364	WA		(3,077,675)	
Distribution Plant Five Year Average Removals	364	WYP		(4,413,224)	
				749,964,651	

PacifiCorp
Oregon General Rate Case - December 2023
Pro Forma Plant Additions
General Plant Additions

Project Description	FERC Account	Factor	Inservice Date	July21 to Dec22 Plant Adds	Ref.
PP Core IT and TOM Hardware Equipment	397	SO	various	30,784,123	
AMI - IT Comm Network	397	SO	Dec-22	17,481,960	**8.4.31**
Replace Vehicles - UT	397	UT	Various	15,459,141	
Lloyd Center Tower Open Office	397	SO	various	12,706,413	**8.4.31**
AMI - Utah Field Area Network	397	UT	Dec-22	10,374,440	
PP Vehicles OR	397	OR	various	9,416,788	
PP Com Plant OR	397	OR	various	8,902,871	
AMI - Idaho IT Comm Network	397	SO	Dec-22	7,322,089	
Replace Vehicles - WY	397	WYP	Various	7,143,176	
WestSmart@Scale – EV Infrastructure	397	UT	Various	6,055,538	
PP Com Plant UT	397	UT	various	5,317,513	
PP Hydro Vehicles	397	SG	Various	4,496,952	
PP Hydro General Plant	397	SG	Various	3,605,449	
RMPGen - SitusUT Investment Programs	397	UT	Various	3,016,525	
PP Com Plant WY	397	WYP	various	2,835,003	
Replace Vehicles - ID	397	ID	Various	2,605,152	
PP Com Main Grid - East	397	SG	Aug-21	2,496,505	
PP Structures OR	397	OR	various	2,062,095	
Alcatel Lucent DMX-Nickel Mtn Glendale	397	OR	Dec-21	2,038,159	
Replace Other General Plant - UT	397	UT	Various	1,999,584	
RMPGen - Alloc Investment Programs	397	SO	Various	1,800,000	
Oracle Exadata/Shared hosting TOM	397	SO	May-22	1,713,600	
Monarch PAC6 Upgrade and HW TOM	397	SO	Nov-21	1,638,690	
Replace Other General Plant - WY	397	WYP	Various	1,498,172	
Replace Tools - UT	397	UT	Various	1,486,307	
Replace Vehicles - Electric Purchase	397	UT	Various	1,478,291	
Calapooya to Mckenzie Fiber Install	397	OR	Dec-21	1,432,013	
PP General Plant OR	397	OR	various	1,394,270	
Cutler to Rabbit Mtn MW Replacement	397	SG	Dec-22	1,344,468	
Dave Johnston U0 - Rebuild D10R Dozer	397	SG	Dec-22	1,326,659	
PP Vehicles WA	397	WA	various	1,324,054	
PP IT Business Requested Hardware Equipment	397	SO	various	1,225,195	
Wildfire Mitigation - Gen-Situs	397	UT	Various	1,200,272	
Alvey to McKenzie Fiber Install	397	SG	Dec-22	1,021,217	
PP Com Plant WA	397	WA	various	1,007,176	
Projects Less Than $1million	397	CA	Various	1,636,111	
Projects Less Than $1million	397	SG	Various	5,400,277	
Projects Less Than $1million	397	ID	Various	2,133,024	
Projects Less Than $1million	397	OR	Various	-	
Projects Less Than $1million	397	SO	Various	6,369,167	
Projects Less Than $1million	397	UT	Various	2,228,160	
Projects Less Than $1million	397	WA	Various	551,491	
Projects Less Than $1million	397	WYP	Various	1,039,896	
General Plant Five Year Average Removals	397	SO		(1,707,521)	
				194,660,464	

PacifiCorp
Oregon General Rate Case - December 2023
Pro Forma Plant Additions
Intangible Plant Additions

Project Description	FERC Account	Factor	Inservice Date	July21 to Dec22 Plant Adds	Ref.
PP Core IT and TOM Software	303	SO	various	14,233,137	
Maximo Phase 1A	303	SO	Jun-22	10,486,213	**8.4.32**
CX Engagement	303	SO		9,248,663	
Monarch PAC6 Upgrade and HW TOM	303	SO	Nov-21	6,554,759	
Mapping Sys Consolidation	303	SO	Jan-22	3,672,800	
CX Communications	303	SO		3,436,541	
SunNet iTOA (Compass Repl)	303	SO	Dec-21	3,182,959	
PP IT Business Requested Software	302	SO	various	3,142,416	
UII RVN Replacement	303	SO	Jun-22	1,713,600	
ARCOS Callout Crew Availability System	303	SO	Aug-21	1,268,568	
Replace IAM-Scheduling/Tagging Power	303	SO	Sep-21	1,024,559	
Projects Less Than $1million	303	OR	Various	-	
Projects Less Than $1million	303	SO	Various	7,030,432	
				64,994,648	

PacifiCorp
Oregon General Rate Case - December 2023
Plant Retirements
5 Year Average Retirement Amount

Function	Factor	CODE	FY2017 (CY2016) Retirements	FY2018 (CY2017) Retirements	FY2019 (CY2018) Retirements	FY2020 (CY2019) Retirements	FY2021 (CY2020) Retirements	Large Items to Exclude	5 Year Avg	Monthly Amount
STMP	DGU	STMPDGU	(60,466,542)	(3,295,196)	(3,805,358)	(27,141,648)	(2,191,253)	64,586,742	(6,462,651)	(538,554)
STMP	DGP	STMPDGP	(11,698,034)	(5,214,803)	(4,346,678)	(4,077,521)	(2,667,943)	3,286,891	(4,943,618)	(411,968)
STMP	SSGCH	STMPSSGCH						-	-	-
STMP	SG	STMPSG	(122,676,137)	(37,870,150)	(41,678,721)	(72,453,873)	(30,626,315)	118,200,856	(37,420,868)	(3,118,406)
STMP	NUTIL	STMPNUTIL	(9,037,852)	(9,000,747)	-	-	-	-	(3,607,720)	(300,643)
			(203,878,565)	(55,380,895)	(49,830,757)	(103,673,042)	(35,485,512)	186,074,489	(52,434,856)	(4,369,571)
HYDP	SG-U	HYDPSG-U	(69,704)	(208,532)	(669,210)	(688,887)	(596,216)	-	(446,510)	(37,209)
HYDP	SG-P	HYDPSG-P	(534,323)	(1,069,662)	(3,174,454)	(2,760,652)	(4,743,569)	1,277,015	(2,201,129)	(183,427)
HYDP	DGU	HYDPDGU	(35,672)	(187,001)	(523,331)	(406,073)	(819,933)	-	(394,402)	(32,867)
HYDP	DGP	HYDPDGP	(690,292)	(321,786)	(874,490)	(460,328)	(703,798)	43,446	(601,450)	(50,121)
HYDP	NUTIL	HYDPNUTIL	-	-	-	-	-	-	-	-
			(1,329,991)	(1,786,981)	(5,241,484)	(4,315,941)	(6,863,517)	1,320,461	(3,643,490)	(303,624)
OTHP	DGU	OTHPDGU	-	-	-			-	-	-
OTHP	SG	OTHPSG	(52,023,479)	(1,957,257)	(16,761,294)	(963,453)	(50,697,982)	-	(24,480,693)	(2,040,058)
OTHP	SG-W	OTHPSG-W	(6,963,155)	(4,776,936)	(82,725)	(844,072,708)	(412,145,767)	1,253,727,992	(2,862,660)	(238,555)
OTHP	SSGCT	OTHPSSGCT	(401,147)	(187,547)	(2,256,844)	73,283	-	-	(554,451)	(46,204)
OTHP	NUTIL	OTHPNUTIL	-	-	-	-	-	-	-	-
			(59,387,781)	(6,921,740)	(19,100,863)	(844,962,878)	(462,843,749)	1,253,727,992	(27,897,804)	(2,324,817)
TRNP	DGP	TRNPDGP	(1,393,287)	(2,977,569)	(1,293,599)	(2,194,511)	(2,231,965)	-	(2,018,186)	(168,182)
TRNP	DGU	TRNPDGU	(3,069,434)	(2,818,962)	(7,288,536)	(2,125,822)	(2,425,425)	-	(3,545,636)	(295,470)
TRNP	JBG	TRNPJBG	-	-	-	-	-	-	-	-
TRNP	SG	TRNPSG	(8,479,048)	(9,180,945)	(7,082,678)	(9,584,949)	(9,274,706)	-	(8,720,465)	(726,705)
TRNP	NUTIL	TRNPNUTIL	-	-	-	-	-	-	-	-
			(12,941,768)	(14,977,477)	(15,664,813)	(13,905,283)	(13,932,096)	-	(14,284,287)	(1,190,357)
DSTP	CA	DSTPCA	(767,723)	(691,930)	(4,729,076)	(1,367,157)	(1,186,564)	-	(1,748,490)	(145,707)
DSTP	ID	DSTPID	(1,625,059)	(1,736,718)	(2,203,340)	(1,930,395)	(1,813,227)	-	(1,861,748)	(155,146)
DSTP	MT	DSTPMT	-	-	-	-	-	-	-	-
DSTP	OR	DSTPOR	(7,879,266)	(9,930,730)	(42,097,594)	(33,806,510)	(12,101,471)	-	(21,163,114)	(1,763,593)
DSTP	UT	DSTPUT	(20,468,213)	(13,156,488)	(16,986,844)	(16,190,768)	(18,052,141)	-	(16,970,891)	(1,414,241)
DSTP	WA	DSTPWA	(1,866,808)	(1,797,818)	(2,504,228)	(3,224,732)	(2,535,929)	-	(2,385,903)	(198,825)
DSTP	WYP	DSTPWYP	(2,992,348)	(3,232,370)	(3,122,221)	(3,763,963)	(3,192,347)	-	(3,260,650)	(271,721)
DSTP	WYU	DSTPWYU	(374,558)	(241,028)	(296,106)	(325,291)	(430,096)	-	(333,416)	(27,785)
DSTP	NUTIL	DSTPNUTIL	-	-	-	-	-	-	-	-
			(35,973,974)	(30,787,082)	(71,939,410)	(60,608,816)	(39,311,775)	-	(47,724,211)	(3,977,018)
GNLP	SE	GNLPSE	(234,645)	(24,616)	(130,808)	(36,551)	(467,235)	-	(178,771)	(14,898)
GNLP	SSGCT	GNLPSSGCT	-	-	-	-	-	-	-	-
GNLP	SG	GNLPSG	(7,978,440)	(5,884,655)	(5,290,627)	(4,624,892)	(10,925,287)	-	(6,940,780)	(578,398)
GNLP	DGP	GNLPDGP	(354,539)	(246,476)	(10,091)	(55,490)	(168,438)	-	(167,007)	(13,917)
GNLP	DGU	GNLPDGU	(414,250)	(1,280)	(70,539)	(115,871)	(1,244,766)	-	(369,341)	(30,778)
GNLP	SO	GNLPSO	(13,123,182)	(12,981,865)	(12,881,251)	(25,844,820)	(13,374,457)	-	(15,641,115)	(1,303,426)
GNLP	CN	GNLPCN	(1,021,984)	(598,547)	(3,163,468)	(384,219)	(797,489)	-	(1,193,141)	(99,428)
GNLP	CA	GNLPCA	(107,582)	(99,292)	(715,495)	(717,531)	(981,422)	-	(524,264)	(43,689)
GNLP	ID	GNLPID	(740,915)	(310,512)	(1,368,673)	(1,285,289)	(429,609)	-	(826,999)	(68,917)
GNLP	SSGCH	GNLPSSGCH						-	-	-
GNLP	OR	GNLPOR	(4,306,824)	(2,634,074)	(5,945,198)	(4,543,677)	(1,961,890)	-	(3,878,333)	(323,194)
GNLP	UT	GNLPUT	(4,549,271)	(3,346,788)	(7,770,797)	(4,139,974)	(8,951,496)	-	(5,751,665)	(479,305)
GNLP	WA	GNLPWA	(1,613,793)	(856,950)	(1,132,533)	(2,705,376)	(604,195)	-	(1,382,569)	(115,214)
GNLP	WYU	GNLPWYU	(510,756)	(319,125)	(493,517)	(343,869)	(235,183)	-	(380,490)	(31,708)
GNLP	WYP	GNLPWYP	(5,754,744)	(1,903,007)	(3,446,458)	(2,626,180)	(1,527,523)	-	(3,051,582)	(254,299)
GNLP	NUTIL	GNLPNUTIL	-	-	-	-	-	-	-	-
			(40,710,925)	(29,207,187)	(42,419,454)	(47,423,739)	(41,668,990)	-	(40,286,059)	(3,357,172)
MNGP	CAEE	MNGPCAEE							-	-
MNGP	NUTIL	MNGPNUTIL							-	-
			-	-	-	-	-	-	-	-
INTP	JBG	INTPJBG	-	-	-	-	-	-	-	-
INTP	SG-P	INTPSG-P	-	-	-	(279,935)	-	-	(55,987)	(4,666)
INTP	SG-U	INTPSG-U	-	-	-	-	(895,226)	-	(179,045)	(14,920)
INTP	SG	INTPSG	(677,401)	(220,378)	(1,546,900)	(62,921)	(1,268,060)	-	(755,132)	(62,928)
INTP	SO	INTPSO	(42,906,524)	(4,298,237)	(5,104,327)	(8,329,898)	(6,745,772)	-	(13,476,952)	(1,123,079)
INTP	CN	INTPCN	(50,673)	(1,982,186)	(10,680)	(8,081)	-	-	(410,324)	(34,194)
INTP	SE	INTPSE	(221,464)	(8,646)	(14,653)	-	-	-	(48,953)	(4,079)
INTP	CA	INTPCA	-	-	-	-	-	-	-	-
INTP	ID	INTPID	-	(5,175)	-	-	-	-	(1,035)	(86)
INTP	OR	INTPOR	-	-	(21,797)	-	-	-	(4,359)	(363)
INTP	UT	INTPUT	-	(28,178)	-	-	(5,507)	-	(6,737)	(561)
INTP	WA	INTPWA	-	-	-	-	-	-	-	-
INTP	WYU	INTPWYU	-	-	-	-	-	-	-	-
INTP	WYP	INTPWYP	(463,713)	-	-	-	-	-	(92,743)	(7,729)
			(44,319,775)	(6,542,800)	(6,698,358)	(8,680,835)	(8,914,565)	-	(15,031,267)	(1,252,606)
			(398,542,779)	(145,604,162)	(210,895,138)	(1,083,570,534)	(609,020,203)	1,441,122,943	(201,301,975)	(16,775,165)

PacifiCorp
Oregon General Rate Case – December 2023
Pro Forma Plant Addition Descriptions
Projects Greater Than $10 Million

STEAM PLANT ADDITIONS:

U0 Huntington Water Redirect; U0 Land Application Conversion (Reference page 8.4.19) (in-Service Oct-21)
Process water has historically been transported to the evaporation/holding pond for storage and then used as land application water as permitted by the original ground water permit. With the renewal of the ground water permit on April 1, 2018, this option was removed and the plant needed an alternative method for managing process water. This alternative method would instead route the water to either the Reverse Osmosis (RO) system for treatment or to the existing brine concentrator. During upset conditions more wastewater may be generated than the combination of the RO and brine concentrator can dispose of. At those times water will be sent to the evaporation/holding pond for storage. A level will be maintained in the evaporation pond that will maximize evaporation while maintaining adequate volume to allow draining of cooling towers if needed. When the level of the pond needs to be adjusted water will either be directed to the pond or returned to the plant for treatment and reuse.

HYDRO PLANT ADDITIONS:

Merwin Downstream In-Lieu (Reference page 8.4.20) (in-service Dec-22)
Per the 2004 Lewis River Settlement Agreement and incorporated by the Federal Energy Regulatory Commission licenses for the Merwin Hydroelectric project, the National Marine Fisheries Service and US Fish and Wildlife Service (“Services”) may elect that PacifiCorp mitigate project impacts to anadromous fish through aquatic habitat restoration projects in-lieu of constructing fish passage into and out of Merwin Reservoir. The Settlement Agreement identifies the amount of in-lieu funding to be spent upon the Services determination and is included in this project. Project also includes identification of habitat projects, consultation with settlement parties, permitting and construction of aquatic habitat projects that benefit anadromous fish.

OTHER PLANT ADDITIONS:

TB Flats Wind Project 500 MW 2020 (Reference page 8.4.21) (in-service various)
The TB Flats wind energy facility has a nominal capacity of 500 MW. The combined resource is located on a site approximately seven miles north, at its most southern boundary, of the town of Medicine Bow, in Carbon County, Wyoming. The project consists of 14 Vestas model V110-2.0 MW-80 hub height and 51 Vestas model V136-4.3 MW-82 WTGs for TB Flats I, and an additional 14 Vestas model V110-2.0 MW-80 and 53 Vestas model V136-4.3 MW-82 WTGs for TB Flats II; 34.5 kilovolt (“kV”) underground collector systems; a TB Flats I collector substation; a TB Flats II collector substation; an approximately 11-mile long 230 kV transmission tie-line from the south area TB II collector substation to the north area TB I collector substation; an O&M building; approximately 40 miles of WTG site access roads; meteorological evaluation towers; a SCADA control system; and approximately 500 feet of 230 kV short span transmission tie-line interconnecting the project from the TB I collector substation to the existing Shirley Basin substation at 230 kV. The in-service dates for the project were December 2020 through July 2021.

Currant Creek U1 CSA Variable Fee - CTA MI (Reference page 8.4.21) (in-service Oct-21)
This project is required to maintain reliability of combustion turbine No. 1A. Without this work, the unit will be susceptible to failure of certain components resulting in a forced outage and subsequent loss of generation. The Currant Creek Plant amended its Contractual Services Agreement (CSA) with General Electric (GE) on January 15, 2016. This agreement requires the company to pay a factored fired hour (FFH) fee to GE for each hour the combustion turbine operates. In return for the quarterly FFH payments, GE provides all combustion parts and services in accordance with the CSA agreement. In accordance with the CSA, this major inspection overhaul is to be conducted when the combustion turbine has operated for approximately 32,000 hours or 1200 starts, whichever occurs first. This major inspection is scheduled to commence in 2021 based on operating hours.

PacifiCorp
Oregon General Rate Case – December 2023
Pro Forma Plant Addition Descriptions
Projects Greater Than $10 Million

Currant Creek U2 CSA Variable Fee - CTB MI (Reference page 8.4.21) (in-service Oct-21) This project is required to maintain reliability of combustion turbine No. 1B. Without this work, the unit will be susceptible to failure of certain components resulting in a forced outage and subsequent loss of generation. The Currant Creek Plant amended its Contractual Services Agreement (CSA) with General Electric (GE) on January 15, 2016. This agreement requires the company to pay a factored fired hour (FFH) fee to GE for each hour the combustion turbine operates. In return for the quarterly FFH payments, GE provides all combustion parts and services in accordance with the CSA agreement. In accordance with the CSA, this major inspection overhaul is to be conducted when the combustion turbine has operated for approximately 32,000 hours or 1200 starts, whichever occurs first. This major inspection is scheduled to commence in 2021 based on operating hours.

Chehalis U1 CSA Variable fee - CT1 - HGP (Reference page 8.4.21) (in-Service Apr-22)
This project is required to maintain reliability of combustion turbine 1. Without this work, the unit will be susceptible to failure of certain components resulting in a forced outage and subsequent loss of generation. The Chehalis Plant amended its Contractual Services Agreement (CSA) with General Electric (GE) on January 15, 2016. This agreement requires the company to pay a factored fired hour (FFH) fee to GE for each hour the combustion turbine operates. In return for the quarterly FFH payments, GE provides all combustion parts and services in accordance with the CSA agreement. In accordance with the CSA, this major inspection overhaul is to be conducted when the combustion turbine has operated for approximately 32,000 hours or 1200 starts, whichever occurs first.

Chehalis U2 CSA Variable fee - CT2 - HGP (Reference page 8.4.21) (in-service Apr-22)
This project is required to maintain reliability of combustion turbine 2. Without this work, the unit will be susceptible to failure of certain components resulting in a forced outage and subsequent loss of generation. The Chehalis Plant amended its Contractual Services Agreement (CSA) with General Electric (GE) on January 15, 2016. This agreement requires the company to pay a factored fired hour (FFH) fee to GE for each hour the combustion turbine operates. In return for the quarterly FFH payments, GE provides all combustion parts and services in accordance with the CSA agreement. In accordance with the CSA, this major inspection overhaul is to be conducted when the combustion turbine has operated for approximately 32,000 hours or 1200 starts, whichever occurs first.

Pryor Mtn Wind Project 240 MW 2020 (Reference page 8.4.21) (in-service various)
The Pryor Mountain wind project will have a nominal rated capacity of 240 MW. The resource will be located on a site in Carbon County, Montana, approximately sixty miles south of Billings, Montana. The project consists of 110 Vestas Model 110-2.0/2.2 MW wind turbines and four General Electric Model 116-2.3 MW wind turbines. In addition to the 114 wind turbines there will be a 34.5 kilovolt (“kV”) collector system; a collector substation with two 34.5 kV to 230 kV step-up transformers, an O&M building and site access roads. Under a separate APR, PacifiCorp, as the transmission provider, will construct a new point of interconnection substation located on the project site in Montana. The in-service dates for the project were December 2020 through March 2021, and the entire project was declared in Commercial Operation April 1, 2021.

<u>TRANSMISSION PLANT ADDITIONS:</u>

Goshen-Sugarmill-Rigby 161kV Transmission Line (Reference 8.4.22) (in-service Jan-22)
This project addresses overloading on the Goshen to Rigby and Goshen to Sugarmill lines in Idaho by converting the lines from 69kV to 161kV. The line from Goshen Substation to Sugarmill substation was completed in 2020 and 2021. The line from Sugarmill to Rigby will be completed in 2022. This includes a 12-miles of new 161kV shared transmission line with Idaho Falls power.

PacifiCorp
Oregon General Rate Case – December 2023
Pro Forma Plant Addition Descriptions
Projects Greater Than $10 Million

Jordanelle - Midway Construct 138 kV Line – Trans (Reference 8.4.22) (in-service Dec-21)
This project will:

- Construct 9 miles of 138 kilovolt transmission line between the Midway and Jordanelle substations
- Add a three 138 kilovolt breaker ring bus at the Midway substation
- Add fiber optic communications between the Silver Creek and Midway substations
- Install protection and control upgrades at all affected substations

The line siting will substantively follow Heber Light and Power's (HLP) existing 46 kilovolt line across the Heber Valley. The structures will be owned by Rocky Mountain Power (RMP) and, for portions, HLP will have circuits and other facilities attached to RMP structures. After project completion, the Summit and Wasatch County system will be capable of operating in a looped configuration for area load levels up to 245 megawatts.

Klamath Falls - Snow Goose 230 kV Line No. 2 TPL (Reference 8.4.22) (in-service Nov-22)
This project builds a second 230 kV transmission line from Snow Goose to Klamath Falls substation located in Klamath County, Oregon.

The overall project is needed to maintain compliance with the North American Electric Reliability Corporation (NERC) Reliability Standard TPL-001-4 and Western Electricity Coordinating Council (WECC) Criterion TPL-001-WECC-CRT-3.1 for double contingencies on the 230 kV system serving Yreka, Klamath Falls and La Pine area. The TPL-001-4 category P6 (N-1-1) contingency for the loss of the Klamath Falls-Snow Goose 230 kV line and either the Lone Pine-Copco 230 kV line or Bonneville Power Administration's (BPA) Pilot Butte-La Pine 230 kV line can cause a voltage collapse affecting a large region of the southern Oregon and northern California system. The proposed transmission line will mitigate risks on the existing system by reinforcing the area 230 kV system with a new source from Snow Goose.

Rexburg Sub - Inst 161kV Source from Rigby (Reference 8.4.22) (in-service Nov-21)
This project will convert an existing 69 kV line to 161 kV operation, increase capacity on Rexburg transformer #2 and regulators, and establish a new 161 kV source at Rexburg substation.

This overall project addresses overloading on the Rexburg transformer #2 regulators and low voltage on the 69 kV Rigby-St. Anthony and Rigby-Webster loop. It also addresses N-1 overloading on the Rigby 161-69 kV transformers and 69 kV line capacity north of Rigby.

Pacific Power Transmission Wildfire Mitigation Projects (Reference 8.4.22) (in-service various)
Projects will include:

- Rebuild transmission lines that are approaching the end of their useful life in Fire High Consequence Areas to new wildfire safe designs
- Modify existing transmission lines to new wildfire safe designs
- Replace outdated electromechanical relays protecting transmission lines in Fire High Consequence Areas with modern microprocessor relays that provide more accurate data that is required in Fire High Consequence Areas
- Add fiber optic communication between substations in the Fire High Consequence Areas to improve protective relaying schemes

These projects will result in decreased risk of transmission equipment failure during the wildfire season, which is increasing in length every year. Modern relaying will enable line patrols to quickly locate and fix any problems, restoring service to customers faster. Fiber optic communications between substations in Fire High Concern Areas will improve the clearing times for protective relaying schemes, which will reduce the time the fault is active. New wildfire safe designs on the transmission system will improve the survivability of the lines in the event that a wildfire does occur.

PacifiCorp
Oregon General Rate Case – December 2023
Pro Forma Plant Addition Descriptions
Projects Greater Than $10 Million

Rocky Mountain Power Transmission Wildfire Mitigation (Reference 8.4.22) (in-service various)
Projects will include:

- Rebuild transmission lines that are approaching the end of their useful life in Fire High Consequence Areas to new wildfire safe designs
- Modify existing transmission lines to new wildfire safe designs
- Replace outdated electromechanical relays protecting transmission lines in Fire High Consequence Areas with modern microprocessor relays that provide more accurate data that is required in Fire High Consequence Areas
- Add fiber optic communication between substations in the Fire High Consequence Areas to improve protective relaying schemes

These projects will result in decreased risk of transmission equipment failure during the wildfire season, which is increasing in length every year. Modern relaying will enable line patrols to quickly locate and fix any problems, restoring service to customers faster. Fiber optic communications between substations in Fire High Concern Areas will improve the clearing times for protective relaying schemes, which will reduce the time the fault is active. New wildfire safe designs on the transmission system will improve the survivability of the lines in the event that a wildfire does occur.

Jim Bridger 345-230 kV Transformer 2 Upgrade (Reference 8.4.22) (PP) (in-service Oct-21)
This project replaces the existing Jim Bridger 345/230 kV transformer #2 (200 MVA) with a new 700 MVA transformer resolving thermal overload issues on the existing transformer and maintains compliance with North American Electric Reliability Corporation (NERC) Reliability Standard TPL-001-4 Category P1 and P3.

DISTRIBUTION PLANT ADDITIONS:

Wildfire - Dist – OR (Reference 8.4.23) (in-service various)
This project outlines the preventative strategies and programs PacifiCorp will implement to its electric distribution and transmission infrastructure that will minimize the risk that causes wildfires. Due to the growing threat of wildfire in the western United States, PacifiCorp has developed a comprehensive wildfire mitigation plan. This plan will guide PacifiCorp's efforts to minimize the chances of a fire igniting from any of PacifiCorp's facilities. This project details PacifiCorp's planned efforts to construct, maintain, and operate its electrical lines and equipment in a manner that will minimize the risk of catastrophic wildfire

GENERAL PLANT ADDITIONS:

AMI - IT Comm Network (Reference page 8.4.25) (in-service Dec-22)
This project will update and configure the head-end AMI software and upgrade the company's current Energy Usage Website while maintaining integration with legacy computer systems. This upgrade will provide additional capacity to allow for future customer growth across all states. The head-end enables the utility to use the data captured by the smart meter to provide accurate customer bills, interval consumption data to customers and send remote commands such as connect or disconnect to the smart meter.

Lloyd Center Tower Open Office (Reference page 8.4.25) (in-service various)
This project provides for the remodeling of the Lloyd Center Tower (LCT) building in Portland, Oregon, to a concept that allows for greater employee engagement. The remodel is expected to create a sustainable competitive advantage ultimately benefitting customers through higher employee retention and recruitment, enhanced productivity, and greater operational performance. Assets will include architectural services, construction of conference rooms and enclaves. It includes the installation of power/data/phone wiring, flooring, furniture, appliances, and finishes on the floors. Construct and furnish two common breakrooms: one breakroom on floor 6 and another on floor 18. Project will be completed

by the end of 2022.

INTANGIBLE PLANT ADDITIONS:

Maximo Phase 1A (Reference page 8.4.26) (in-Service Jun-22)
Maximo is a world-class enterprise asset management software. With an average system age of 17 years, 80 percent of the core asset and work management systems at the BHE companies are beyond end-of-life. Modernizing enterprise asset management capabilities will lower or eliminate the costs and complexities associated with outdated systems. System integration will allow us to better serve our customers while adhering to compliance timelines through reduced costs, increased security and simplified processes across the business. Implementing a standardized tool for asset and work management across BHE will enable standardized processes, universal visibility and master data integrity – including data driven reporting, analysis and decision making – positioning us to be a more agile organization, improve the employee experience and better serve our customers. Maximo Phase 1A rollout for PacifiCorp is scheduled for in-service in Q2 2022 and will focus on substation operations, including preventative maintenance scheduling and field inspection results collection.

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	26.070%	5,735,183	8.5.1
			-			5,089,393	

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.

PacifiCorp
Oregon General Rate Case - December 2023
Customer Advances for Construction

END OF PERIOD BASIS:

Account	Booked Allocation	Correct Allocation	Adjustment	Ref.
252CA	-	(116,018)	**(116,018)**	**Page 8.5**
252OR	(1,424,117)	(2,069,907)	**(645,790)**	**Page 8.5**
252WA	-	(683,516)	**(683,516)**	**Page 8.5**
252IDU	-	(1,345,561)	**(1,345,561)**	**Page 8.5**
252UT	(115,759)	(17,212,903)	**(17,097,144)**	**Page 8.5**
252WYP	-	(2,110,851)	**(2,110,851)**	**Page 8.5**
252SG	(30,469,074)	(8,470,195)	**21,998,879**	**Page 8.5**
Total	**(32,008,950)**	**(32,008,950)**	**-**	

PacifiCorp
Oregon General Rate Case - December 2023
Regulatory Assets & Liabilities Amortization

Note: Please see Confidential Exhibit PAC/1008 for redacted information.

	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_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	26.070%	(1,226,925)	8.6.1
TE Pilot Deferral Amort.	407	3	974,165	OR	Situs	974,165	8.6.4
Oregon Depreciation Decrease Deferral	407	3	(2,828,006)	OR	Situs	(2,828,006)	8.6.9
Adjustment to Rate Base:							
Elec. Plant Gross Acq.	114	3	(141,186,243)	SG	26.070%	(36,807,736)	8.6.1
Elec. Plant Acq. Acc. Amort.	115	3	137,153,218	SG	26.070%	35,756,313	8.6.1
Adjustment to Tax:							
Schedule M Adjustment	SCHMAT	3	974,165	OR	Situs	974,165	8.6.4
Deferred Income Tax Expense	41110	3	(239,520)	OR	Situs	(239,520)	8.6.4
Schedule M Adjustment	SCHMDT	3	[redacted]	OR	Situs	[redacted]	8.6.5_CONF
Deferred Income Tax Expense	41010	3		OR	Situs		8.6.5_CONF
Schedule M Adjustment	SCHMAT	3	[redacted]	OR	Situs	[redacted]	8.6.7_CONF
Deferred Income Tax Expense	41010	3		OR	Situs		8.6.7_CONF
Schedule M Adjustment	SCHMDT	3	2,828,006	OR	Situs	2,828,006	8.6.9
Deferred Income Tax Expense	41110	3	695,313	OR	Situs	695,313	8.6.9

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).

PacifiCorp PAGE 8.6.1
Oregon General Rate Case - December 2023
Regulatory Assets & Liabilities Amortization
Electric Plant Acquisition Adjustment

Adjust Base Period to Pro Forma Period

		Rate Base	
	Amortization	Gross Acq.	Acc Amort
Pro Forma Amount (below)	75,351	3,518,456	(827,259)
Base Period Amount (below)	4,781,559	144,704,699	(137,980,477)
Pro Forma Adjustment	**(4,706,208)**	**(141,186,243)**	**137,153,218**
	Ref. 8.6	**Ref. 8.6**	**Ref. 8.6**

Year		Gross Acquisition	Beg Balance Accumlated Amortization	Amortization	End Balance Accumulated Amortization	13 Month Avg Bal Gross Acq	13 Month Avg Bal Acc Amort
	Opening Balance	144,704,699			(133,198,918)		
2020	July	144,704,699	(133,198,918)	(398,463)	(133,597,381)		
	August	144,704,699	(133,597,381)	(398,463)	(133,995,844)		
	September	144,704,699	(133,995,844)	(398,463)	(134,394,308)		
	October	144,704,699	(134,394,308)	(398,463)	(134,792,771)		
	November	144,704,699	(134,792,771)	(398,463)	(135,191,234)		
	December	144,704,699	(135,191,234)	(398,463)	(135,589,698)		
2021	January	144,704,699	(135,589,698)	(398,463)	(135,988,161)		
	February	144,704,699	(135,988,161)	(398,463)	(136,386,624)		
	March	144,704,699	(136,386,624)	(398,463)	(136,785,087)		
	April	144,704,699	(136,785,087)	(398,463)	(137,183,551)		
	May	144,704,699	(137,183,551)	(398,463)	(137,582,014)		
	June	144,704,699	(137,582,014)	(398,463)	(137,980,477)	144,704,699	(135,589,698)
			Base Period Amort =	(4,781,559)			
2021	July	144,704,699	(137,980,477)	(398,463)	(138,378,940)		
	August	144,704,699	(138,378,940)	(398,463)	(138,777,404)		
	September	144,704,699	(138,777,404)	(398,463)	(139,175,867)		
	October	144,704,699	(139,175,867)	(398,463)	(139,574,330)		
	November	144,704,699	(139,574,330)	(398,463)	(139,972,794)		
	December	144,704,699	(139,972,794)	(398,463)	(140,371,257)		
2022	January	144,704,699	(140,371,257)	(398,463)	(140,769,720)		
	February	144,704,699	(140,769,720)	(398,463)	(141,168,183)		
	March	144,704,699	(141,168,183)	(398,463)	(141,566,647)		
	April	144,704,699	(141,566,647)	(358,945)	(141,925,591)		
	May	3,518,456	(739,349)	(6,279)	(745,628)		
	June	3,518,456	(745,628)	(6,279)	(751,907)		
	July	3,518,456	(751,907)	(6,279)	(758,187)		
	August	3,518,456	(758,187)	(6,279)	(764,466)		
	September	3,518,456	(764,466)	(6,279)	(770,745)		
	October	3,518,456	(770,745)	(6,279)	(777,024)		
	November	3,518,456	(777,024)	(6,279)	(783,304)		
	December	3,518,456	(783,304)	(6,279)	(789,583)		
2023	January	3,518,456	(789,583)	(6,279)	(795,862)		
	February	3,518,456	(795,862)	(6,279)	(802,142)		
	March	3,518,456	(802,142)	(6,279)	(808,421)		
	April	3,518,456	(808,421)	(6,279)	(814,700)		
	May	3,518,456	(814,700)	(6,279)	(820,979)		
	June	3,518,456	(820,979)	(6,279)	(827,259)		
	July	3,518,456	(827,259)	(6,279)	(833,538)		
	August	3,518,456	(833,538)	(6,279)	(839,817)		
	September	3,518,456	(839,817)	(6,279)	(846,097)		
	October	3,518,456	(846,097)	(6,279)	(852,376)		
	November	3,518,456	(852,376)	(6,279)	(858,655)		
	December	3,518,456	(858,655)	(6,279)	(864,934)	3,518,456	(827,259)
			Pro Forma Amort =	(75,351)			

PacifiCorp
Oregon General Rate Case - December 2023
Regulatory Assets & Liabilities Amortization
Electric Plant Acquisition Adjustment
GL Account 140800 - Actuals for 12 Months Ended June 2021

Year	Month	Addition / Amortization	Accumulated Amount
2020	6	-	156,468,483
2020	7	-	156,468,483
2020	8	-	156,468,483
2020	9	-	156,468,483
2020	10	-	156,468,483
2020	11	-	156,468,483
2020	12	-	156,468,483
2021	1	-	156,468,483
2021	2	-	156,468,483
2021	3	-	156,468,483
2021	4	-	156,468,483
2021	5	-	156,468,483
2021	6	-	**156,468,483**

System-allocated amount	144,704,699	**Ref Tab B-15 & 8.6.1**
Utah-situs amount	11,763,784	**Ref Tab B-15**
	156,468,483	

GL Account Balance
Account Number 140800

Calendar year 2020

Period	Debit	Credit	Balance	Cumulative balance
Balance Car...				156,468,482.73
1				156,468,482.73
2				156,468,482.73
3				156,468,482.73
4				156,468,482.73
5				156,468,482.73
6				156,468,482.73
7				156,468,482.73
8				156,468,482.73
9				156,468,482.73
10				156,468,482.73
11				156,468,482.73
12				156,468,482.73

Calendar year 2021

Period	Debit	Credit	Balance	Cumulative balance
Balance Car...				156,468,482.73
1				156,468,482.73
2				156,468,482.73
3				156,468,482.73
4				156,468,482.73
5				156,468,482.73
6				156,468,482.73
7				156,468,482.73
8				156,468,482.73
9				156,468,482.73
10				156,468,482.73
11				156,468,482.73
12				156,468,482.73

PacifiCorp
Oregon General Rate Case - December 2023
Regulatory Assets & Liabilities Amortization
Accumulated Amortization
GL Account 145800 - Actuals for 12 Months Ended June 2021

Year	Month	Amort.	Accumulated Amount
2018	6	(423,600)	(134,794,824)
2018	7	(423,600)	(135,218,423)
2018	8	(423,600)	(135,642,023)
2018	9	(423,600)	(136,065,622)
2018	10	(423,600)	(136,489,222)
2018	11	(423,600)	(136,912,822)
2018	12	(423,600)	(137,336,421)
2019	1	(423,600)	(137,760,021)
2019	2	(423,600)	(138,183,620)
2019	3	(423,600)	(138,607,220)
2019	4	(423,600)	(139,030,819)
2019	5	(423,600)	(139,454,419)
2019	6	(423,600)	**(139,878,019)**

System-allocated amount	(137,980,477)	**Ref. Tab B-15 & 8.6.1**
Utah-situs amount	(1,897,541)	**Ref. Tab B-15**
	(139,878,019)	

GL Account Balance
Account Number 145800
Calendar year 2020

Period	Debit	Credit	Balance	Cumulative balance
Balance Car...				132,253,226.26-
1		423,599.57	423,599.57-	132,676,825.83-
2		423,599.58	423,599.58-	133,100,425.41-
3		423,599.57	423,599.57-	133,524,024.98-
4		423,599.59	423,599.59-	133,947,624.57-
5		423,599.56	423,599.56-	134,371,224.13-
6		423,599.58	423,599.58-	134,794,823.71-
7		423,599.58	423,599.58-	135,218,423.29-
8		423,599.56	423,599.56-	135,642,022.85-
9		423,599.58	423,599.58-	136,065,622.43-
10		423,599.58	423,599.58-	136,489,222.01-
11		423,599.58	423,599.58-	136,912,821.59-
12		423,599.57	423,599.57-	137,336,421.16-

Calendar year 2021

Period	Debit	Credit	Balance	Cumulative balance
Balance Car...				137,336,421.16-
1		423,599.57	423,599.57-	137,760,020.73-
2		423,599.58	423,599.58-	138,183,620.31-
3		423,599.57	423,599.57-	138,607,219.88-
4		423,599.59	423,599.59-	139,030,819.47-
5		423,599.56	423,599.56-	139,454,419.03-
6		423,599.58	423,599.58-	139,878,018.61-
7		423,599.58	423,599.58-	140,301,618.19-
8		423,599.56	423,599.56-	140,725,217.75-
9		423,599.58	423,599.58-	141,148,817.33-
10		423,599.58	423,599.58-	141,572,416.91-
11		423,599.58	423,599.58-	141,996,016.49-
12				141,996,016.49-

PacifiCorp
Oregon General Rate Case - December 2023
Regulatory Assets & Liabilities Amortization
Oregon Transportation Electrification Pilot Programs

	Amortization
Base Period Amount (below)	-
Pro Forma Amount (below)	974,165
Adjustment:	**974,165**
	Ref. 8.6

		Opening Bal.	Accrual[1]	Amortization	Interest[2]	Ending Bal.	SCHMDT	41010
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	81,180	(19,960)
	February	2,763,081	-	81,180	4,252	2,686,152	81,180	(19,960)
	March	2,686,152	-	81,180	4,136	2,609,108	81,180	(19,960)
	April	2,609,108	-	81,180	4,019	2,531,946	81,180	(19,960)
	May	2,531,946	-	81,180	3,902	2,454,667	81,180	(19,960)
	June	2,454,667	-	81,180	3,784	2,377,271	81,180	(19,960)
	July	2,377,271	-	81,180	3,667	2,299,758	81,180	(19,960)
	August	2,299,758	-	81,180	3,550	2,222,127	81,180	(19,960)
	September	2,222,127	-	81,180	3,432	2,144,378	81,180	(19,960)
	October	2,144,378	-	81,180	3,314	2,066,512	81,180	(19,960)
	November	2,066,512	-	81,180	3,196	1,988,527	81,180	(19,960)
	December	1,988,527	-	81,180	3,077	1,910,424	81,180	(19,960)
			Pro Forma Amort =	**974,165**			**974,165**	**(239,520)**
							Ref 8.6	**Ref 8.6**

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
Regulatory Assets & Liabilities Amortization
Pryor Mountain REC Sales Revenue Deferral

PAGE 8.6.5_REDACTED

Note: Please see Confidential Exhibit PAC/1008 for redacted information.

	Amortization
Base Period Amount (below)	-
Pro Forma Amount (below)	[redacted]
Adjustment:	[redacted]
	Ref. 8.6

		Opening Bal.	Accrual[1]	Amortization	Interest[2]	Ending Bal.	SCHMDT	41010
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]	[redacted]	[redacted]
	February	[redacted]	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	March	[redacted]	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	April	[redacted]	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	May	[redacted]	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	June	[redacted]	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	July	[redacted]	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	August	[redacted]	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	September	[redacted]	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	October	[redacted]	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	November	[redacted]	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	December	[redacted]	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
			Pro Forma Amort =	[redacted]				
							Ref 8.6	**Ref 8.6**

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
Regulatory Assets & Liabilities Amortization
Pryor Mountain REC Sales Revenue Forecast

PAGE 8.6.6_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]

Pryor Mountain REC Revenues Amort	[redacted]	Ref 8.6.5
Pryor Mountain REC Revenues Forecast		Above
Tota Pryor Mountain REC Revenues Adjustment		**Ref 8.6**

PacifiCorp
Oregon General Rate Case - December 2023
Regulatory Assets & Liabilities Amortization
FERC OATT Revenues Deferral (Post 2017)

	Amortization
Base Period Amount (below)	[redacted]
Pro Forma Amount (below)	
Adjustment:	
	Ref. 8.6

Note: Please see Confidential Exhibit PAC/1008 for redacted information.

		Opening Bal.	Accrual	Adjustment	Amortization	Interest[1,2]	Ending Bal.
2020	June	[redacted]					
	July						
	August						
	September						
	October						
	November						
	December						
2021	January						
	February						
	March						
	April						
	May						
	June						
				Base Period Amort =	[redacted]		
2021	July	[redacted]					
	August						
	September						
	October						
	November						
	December						
2022	January						
	February						
	March						
	April						
	May						
	June						
	July						
	August						
	September						
	October						
	November						
	December						
2023	January						
	February						
	March						
	April						
	May						
	June						
	July						
	August						
	September						
	October						
	November						
	December						
				Pro Forma Amort =	**4,075,388**		

SCHMDT	**41010**
[redacted]	
Ref 8.6	**Ref 8.6**

Note:
1. Interest rate in deferral period per approved WACC from UE-263.
2. Interest accrual at Modified Blended Treasury Rate as of date of the Commission's approval of the amortization (i.e. Dec 2020)

	2020	
MBTR	2.630%	Ref UM-1147

PacifiCorp
Oregon General Rate Case - December 2023
Regulatory Assets & Liabilities Amortization
FERC OATT Revenues Deferral (Post 2017)
GL Account 288232 - Actuals for 12 Months Ended June 2021

Note: Please see Confidential Exhibit PAC/1008 for redacted information.

Year	Month	Accrual	Adjust.	Amort.	Interest	Accumulated Amount
2020	6	[redacted]				
2020	7					
2020	8					
2020	9					
2020	10					
2020	11					
2020	12					
2021	1					
2021	2					
2021	3					
2021	4					
2021	5					
2021	6					
						Ref 8.6.7

GL Account Balance
Account Number 288232

Calendar year 2020

[redacted]

Calendar year 2021

[redacted]

PacifiCorp
Oregon General Rate Case - December 2023
Regulatory Assets & Liabilities Amortization
Oregon Depreciation Decrease Deferral

	Amortization
Pro Forma Amount (below)	**2,828,006**
	Ref. 8.6

		Opening Bal.	Accrual	Amortization	Interest[1,2]	Ending Bal.			
2020	June	(7,101,371)	(71,566)	-	(45,327)	(7,218,264)			
	July	(7,218,264)	(71,566)	-	(46,069)	(7,335,899)			
	August	(7,335,899)	(71,566)	-	(46,816)	(7,454,281)			
	September	(7,454,281)	(71,566)	-	(47,568)	(7,573,415)			
	October	(7,573,415)	(71,566)	-	(48,325)	(7,693,306)			
	November	(7,693,306)	(71,566)	-	(49,086)	(7,813,958)			
	December	(7,813,958)	(71,566)	-	(49,852)	(7,935,376)			
2021	January	(7,935,376)	-	220,427	(8,086)	(7,723,035)			
	February	(7,723,035)	-	220,658	(7,866)	(7,510,243)			
	March	(7,510,243)	-	220,890	(7,646)	(7,297,000)			
	April	(7,297,000)	-	221,121	(7,426)	(7,083,305)			
	May	(7,083,305)	-	221,353	(7,205)	(6,869,157)			
	June	(6,869,157)	-	221,586	(6,984)	(6,654,555)	Ref 8.6.10		
	July	(6,654,555)	-	221,818	(6,762)	(6,439,498)			
	August	(6,439,498)	-	222,052	(6,539)	(6,223,986)			
	September	(6,223,986)	-	222,285	(6,317)	(6,008,017)			
	October	(6,008,017)	-	222,519	(6,093)	(5,791,591)			
	November	(5,791,591)	-	222,754	(5,870)	(5,574,708)			
	December	(5,574,708)	-	222,988	(5,645)	(5,357,365)			
2022	January	(5,357,365)	-	243,705	(105,128)	(5,218,788)			
	February	(5,218,788)	-	226,904	(11,189)	(5,003,073)			
	March	(5,003,073)	-	227,412	(10,716)	(4,786,376)			
	April	(4,786,376)	-	227,923	(10,240)	(4,568,694)			
	May	(4,568,694)	-	228,435	(9,763)	(4,350,022)			
	June	(4,350,022)	-	228,949	(9,283)	(4,130,356)			
	July	(4,130,356)	-	229,464	(8,801)	(3,909,693)			
	August	(3,909,693)	-	229,982	(8,317)	(3,688,028)			
	September	(3,688,028)	-	230,502	(7,830)	(3,465,357)			
	October	(3,465,357)	-	231,024	(7,342)	(3,241,674)			
	November	(3,241,674)	-	231,548	(6,851)	(3,016,977)		**SCHMDT**	**41010**
	December	(3,016,977)	-	232,075	(6,358)	(2,791,260)		-	-
2023	January	(2,791,260)	-	232,605	(5,863)	(2,564,518)		232,605	(57,190)
	February	(2,564,518)	-	233,138	(5,365)	(2,336,745)		233,138	(57,321)
	March	(2,336,745)	-	233,674	(4,865)	(2,107,936)		233,674	(57,453)
	April	(2,107,936)	-	234,215	(4,363)	(1,878,084)		234,215	(57,586)
	May	(1,878,084)	-	234,760	(3,859)	(1,647,182)		234,760	(57,720)
	June	(1,647,182)	-	235,312	(3,352)	(1,415,223)		235,312	(57,855)
	July	(1,415,223)	-	235,870	(2,843)	(1,182,195)		235,870	(57,993)
	August	(1,182,195)	-	236,439	(2,332)	(948,088)		236,439	(58,132)
	September	(948,088)	-	237,022	(1,818)	(712,884)		237,022	(58,276)
	October	(712,884)	-	237,628	(1,302)	(476,558)		237,628	(58,425)
	November	(476,558)	-	238,279	(783)	(239,062)		238,279	(58,585)
	December	(239,062)	-	239,062	-	-		239,062	(58,777)
			Pro Forma Amort =	**2,828,006**				**2,828,006**	**(695,313)**
								Ref 8.6	**Ref 8.6**

Note:
1. Interest rate in deferral period per approved WACC from UE-263.
2. Interest accrual at Modified Blended Treasury Rate as of date of the Commission's approval of the amortization (i.e. Dec 2020)

	2020	
MBTR	2.630%	Ref UM-1147

PacifiCorp
Oregon General Rate Case - December 2023
Regulatory Assets & Liabilities Amortization
Oregon Depreciation Decrease Deferral
GL Account 288412 - Actuals for 12 Months Ended June 2021

Year	Month	Accrual	Amort.	Interest	Accumulated Amount
2020	6	(71,566)		(45,327)	(7,218,264)
2020	7	(71,566)		(46,069)	(7,335,899)
2020	8	(71,566)		(46,816)	(7,454,281)
2020	9	(71,566)		(47,568)	(7,573,415)
2020	10	(71,566)		(48,325)	(7,693,306)
2020	11	(71,566)		(49,086)	(7,813,958)
2020	12	(71,566)		(49,852)	(7,935,376)
2021	1	-	220,427	(8,086)	(7,723,035)
2021	2	-	220,658	(7,866)	(7,510,243)
2021	3	-	220,890	(7,646)	(7,297,000)
2021	4	-	221,121	(7,426)	(7,083,305)
2021	5	-	221,353	(7,205)	(6,869,157)
2021	6	-	221,586	(6,984)	**(6,654,555)**
					Ref 8.6.9

GL Account Balance
Account Number 288412

Calendar year 2020

Period	Debit	Credit	Balance	Cumulative balance
Balance Car...				6,527,879.58-
1		113,250.61	113,250.61-	6,641,130.19-
2		113,969.88	113,969.88-	6,755,100.07-
3		114,693.69	114,693.69-	6,869,793.76-
4		115,422.09	115,422.09-	6,985,215.85-
5		116,155.11	116,155.11-	7,101,370.96-
6		116,892.80	116,892.80-	7,218,263.76-
7		117,635.16	117,635.16-	7,335,898.92-
8		118,382.24	118,382.24-	7,454,281.16-
9		119,134.07	119,134.07-	7,573,415.23-
10		119,890.67	119,890.67-	7,693,305.90-
11		119,890.67	119,890.67-	7,813,196.57-
12	119,890.67	242,070.40	122,179.73-	7,935,376.30-

Calendar year 2021

Period	Debit	Credit	Balance	Cumulative balance
Balance Car...				7,935,376.30-
1	220,427.12	8,086.00	212,341.12	7,723,035.18-
2	220,658.15	7,866.46	212,791.69	7,510,243.49-
3	220,889.51	7,646.46	213,243.05	7,297,000.44-
4	221,121.23	7,425.99	213,695.24	7,083,305.20-
5	221,353.29	7,205.05	214,148.24	6,869,156.96-
6	221,585.71	6,983.64	214,602.07	6,654,554.89-
7	221,818.50	6,761.77	215,056.73	6,439,498.16-
8	222,051.66	6,539.42	215,512.24	6,223,985.92-
9	222,285.21	6,316.60	215,968.61	6,008,017.31-
10	222,519.16	6,093.32	216,425.84	5,791,591.47-
11	222,753.52	5,869.56	216,883.96	5,574,707.51-
12	222,988.30	5,645.32	217,342.98	5,357,364.53-

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	26.070%	(2,764,295)	
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)			(9,657,872)	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.

PacifiCorp
Oregon General Rate Case - December 2023
FERC 105 (Plant Held for Future Use)

Primary Account		Secondary Account		Alloc	Total
1050000	Plant Held for Future Use	3401000	LAND OWNED IN FEE	SG	8,923,302
1050000	Plant Held for Future Use	3501000	LAND OWNED IN FEE	SG	925,352
1050000	Plant Held for Future Use	3502000	LAND RIGHTS	SG	754,562
1050000	Plant Held for Future Use	3601000	LAND OWNED IN FEE	CA	683,318
1050000	Plant Held for Future Use	3601000	LAND OWNED IN FEE	UT	5,715,537
1050000	Plant Held for Future Use	3601000	LAND OWNED IN FEE	WYP	601
1050000	Plant Held for Future Use	3601000	LAND OWNED IN FEE	OR	3,912,456
1050000	Plant Held for Future Use	3891000	LAND OWNED IN FEE	OR	2,981,121
Total					**23,896,248**

REF 8.7

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	27.173%	(7,786,953)	8.8.1
Net Prepaid Balance	182M	1	(406,817,630)	SO	27.173%	(110,544,888)	8.8.1
Net Prepaid Balance	2283	1	74,432,333	SO	27.173%	20,225,559	8.8.1
			(361,042,159)			(98,106,282)	
Adjustment to Tax:							
ADIT Balances	190	1	(21,054,777)	SO	27.173%	(5,721,232)	8.8.2
ADIT Balances	283	1	109,063,328	SO	27.173%	29,635,867	8.8.2
			88,008,551			23,914,636	

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.

PacifiCorp
Oregon General Rate Case - December 2023
Pension & Other Post-retirement Balances Removal

Pension & Postretirement

FERC Account	Factor	June 2021 End of Period Balances	Ref
128	SO	28,656,862	**8.8**
182M	SO	406,817,630	**8.8**
2283	SO	(74,432,333)	**8.8**
		361,042,159	**8.8**

PacifiCorp
Oregon General Rate Case - December 2023
Pension & Other Post-retirement Balances Removal
Tax Support

		Sch. M Number	SAP Account	EOP 6/2021 Per Tax Model	Adjustment
190	DTA 720.800 FAS 158 Pension Liability	720.800	287460	18,300,380	(18,300,380)
190	FAS 158 Post-Retirement Liability	720.810	287461	-	-
190	DTA 320.279 Reg Liability FAS 158 Post-Ret	320.279	287198	2,754,397	(2,754,397)
283	DTL 720.805 FAS 158 Pension Asset	720.800	287569	(2,045,357)	2,045,357
283	DTL 720.815 FAS 158 Post-Retirement Asset	720.815	286909	(4,240,952)	4,240,952
283	DTL 320.270 Reg Asset FAS 158 Pension	320.270	287738	(103,189,035)	103,189,035
283	DTL 320.280 Reg Asset FAS 158 Post-Ret	320.280	287739	412,016	(412,016)
				(88,008,551)	88,008,551

Summarize Tax Adjustment by Allocation Factor		EOP 6/2021	Adjustment	
190	SO	21,054,777	(21,054,777)	**Ref. 8.8**
283	SO	(109,063,328)	109,063,328	**Ref. 8.8**
		(88,008,551)	88,008,551	

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	26.070%	(906,792)	
Other Plant	343	1	(170,634,366)	SG	26.070%	(44,484,963)	
Other Plant	344	1	(7,930,556)	SG	26.070%	(2,067,523)	
Other Plant	345	1	(12,436,383)	SG	26.070%	(3,242,207)	
Other Plant	346	1	(659,497)	SG	26.070%	(171,933)	
			(195,139,054)			(50,873,419)	8.9.1
Adjustment to Depreciation Reserve:							
Other Plant	108OP	1	(17,881,562)	SG	26.070%	(4,661,784)	8.9.1
Adjustment to O&M Expense:							
Administrative & General	929	1	(431,525)	SO	27.173%	(117,259)	8.9.1
Misc. Oth. Power Supply	549	1	(28,437)	SG	26.070%	(7,414)	8.9.1
Misc. Oth. Power Supply	553	1	(1,112,621)	SG	26.070%	(290,064)	8.9.1
Adjustment to Tax:							
Schedule M Adjustment	SCHMAP	1	85	SCHMDEXP	22.648%	19	
Schedule M Adjustment	SCHMDT	1	(10,880,231)	TAXDEPR	26.410%	(2,873,436)	
Schedule M Adjustment	SCHMDT	1	(9,068)	GPS	27.173%	(2,464)	
Deferred Tax Expense	41010	1	(2,675,079)	TAXDEPR	26.410%	(706,480)	
Deferred Tax Expense	41010	1	(2,230)	GPS	27.173%	(606)	
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.

PacifiCorp
Oregon General Rate - December 2023
Remove Rolling Hills

Rate Base Amounts	FERC Account	EOP 12 ME Jun 2021	Ref.
Capital			
Other Plant	341	3,478,252	
Other Plant	343	170,634,366	
Other Plant	344	7,930,556	
Other Plant	345	12,436,383	
Other Plant	346	659,497	
		195,139,054	8.9
Depreciation Reserve			
Other Plant	108OP	17,881,562	8.9

Expense Amounts	FERC Account	12 ME Jun 2021	Ref.
Operation & Maintenance Expense			
Administrative & General	929	431,525	8.9
Misc. Oth. Power Supply	549	28,437	8.9
Misc. Oth. Power Supply	553	1,112,621	8.9

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	26.070%	(9,223,534)	8.10.1
Add pro forma expense							
UMWA Pension Withdrawal Liability Pymt	926	1	2,967,013	SO	27.173%	806,229	8.10.2
Adjustment to Rate Base:							
Remove base period regulatory assets							
Closure Costs	182M	1	(75,945,690)	SE	25.068%	(19,038,168)	B-16
Unrecovered Plant	182M	1	(2,436,501)	SE	25.068%	(610,785)	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	27.173%	(2,261,635)	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	25.068%	(4,535,742)	
Schedule M Addition	SCHMAT	1	(3,702,799)	SO	27.173%	(1,006,165)	
Schedule M Deduction	SCHMDT	1	(3,264,033)	SE	25.068%	(818,232)	
Schedule M Deduction	SCHMDT	1	(248,200)	OR	Situs	(248,200)	
Def Income Tax Expense	41110	1	4,448,614	SE	25.068%	1,115,185	
Def Income Tax Expense	41110	1	910,392	SO	27.173%	247,382	
Def Income Tax Expense	41010	1	(802,515)	SE	25.068%	(201,176)	
Def Income Tax Expense	41010	1	(61,024)	OR	Situs	(61,024)	
Accum Def Income Tax Balance	283	1	(29,952,417)	SE	25.068%	(7,508,512)	
Accum Def Income Tax Balance	283	1	68,930,513	SE	25.068%	17,279,594	
Accum Def Income Tax Balance	190	1	(28,303,872)	SE	25.068%	(7,095,253)	
Accum Def Income Tax Balance	283	1	595,182	SO	27.173%	161,729	
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.

PacifiCorp
Oregon General Rate Case - December 2023
Deer Creek Mine Adjustment
Treatment of Deer Creek Unrecovered Plant

Deer Creek Closure costs in Wyoming are being allocated on an SG factor which impacts Oregon unadjusted results. We need to remove this from unadjusted results.

	Amort	FERC Account	Allocator	Ref
Wyoming closure cost amortization in unadj results	**35,379,413**	**506**	**SG**	**8.10**

PacifiCorp
Oregon General Rate Case - December 2023
Deer Creek Mine Adjustment
UMWA Pension Withdrawal Liability Payment

Fiscal Year	Posting period	Account Number	FERC Account	FERC Location	Description	In transaction currency
2021	6	278200	2340000	1	UMWA Pension Withdrawal Liability Payment	247,251
2021	5	278200	2340000	1	UMWA Pension Withdrawal Liability Payment	247,251
2021	4	278200	2340000	1	UMWA Pension Withdrawal Liability Payment	247,251
2021	3	278200	2340000	1	UMWA Pension Withdrawal Liability Payment	247,251
2021	2	278200	2340000	1	UMWA Pension Withdrawal Liability Payment	247,251
2021	1	278200	2340000	1	UMWA Pension Withdrawal Liability Payment	247,251
2020	12	278200	2340000	1	UMWA Pension Withdrawal Liability Payment	247,251
2020	11	278200	2340000	1	UMWA Pension Withdrawal Liability Payment	247,251
2020	10	278200	2340000	1	UMWA Pension Withdrawal Liability Payment	247,251
2020	9	278200	2340000	1	UMWA Pension Withdrawal Liability Payment	247,251
2020	8	278200	2340000	1	UMWA Pension Withdrawal Liability Payment	247,251
2020	7	278200	2340000	1	UMWA Pension Withdrawal Liability Payment	247,251
Total						**2,967,013**
						Ref. 8.10

PacifiCorp
Oregon General Rate Case - December 2023
Emissions Control Investment Adjustment

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Hunter Clean Air Disallowance	312	1	(4,649,941)	SG	26.070%	(1,212,256)	8.11.1
Hunter Clean Air Disallowance	108SP	1	325,130	SG	26.070%	84,762	8.11.1
Adjustment to Expense:							
Hunter Clean Air Disallowance	403SP	1	(325,130)	SG	26.070%	(84,762)	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	26.070%	(84,763)	
Schedule M Adjustment	SCHMDT	1	(128,808)	SG	26.070%	(33,581)	
Deferred Income Tax Expense	41110	1	79,938	SG	26.070%	20,840	
Deferred Income Tax Expense	41010	1	(31,670)	SG	26.070%	(8,256)	
Accumulated Def Inc Tax Balance	282	1	471,095	SG	26.070%	122,816	

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.

PacifiCorp
Oregon General Rate Case - December 2023
Emissions Control Equipment Adjustment
Hunter Clean Air Equipment Summary

End of Period Balances as of Dec 31 2022		
EPIS Balance	81,171,892	
Steam Plant Reserve	(34,672,480)	
Net Book Value	46,499,411	
Disallowance Adjustments		
Ordered 10% Disallowance	4,649,941	Ref 8.11
Depreciation Rate[1]	6.992%	
Depreciation Expense	325,130	Ref 8.11
Depreciation Reserve	(325,130)	Ref 8.11

[1] *Actual composite steam depreciation rate for June 2021.*

PacifiCorp PAGE 8.11.2
Oregon General Rate Case - December 2023
Emissions Control Equipment Adjustment
Jim Bridger Unit 3 & 4 SCR Return Adjustments

Pro Forma Adjustment

	Total Co.	OR Allocated
Net Book Value - End of Period Dec 2022	142,268,368	37,089,850
Pre-Tax Rate of Return	8.88%	8.88%
Return on Rate Base_Rate of Return	12,636,012	3,294,252
Return - Cost of Long-Term Debt	4.38%	4.38%
Return on Rate Base_Cost of Debt	6,231,355	1,624,535
Adjustment to Return	(6,404,658)	**(1,669,716)**
		Ref 8.11
System Generation Factor (SG)	26.070%	

PacifiCorp
Oregon General Rate Case - December 2023
Summary of Variables

Proposed Capital Structure and Costs

	Capital Structure	Embedded Cost	Weighted Cost	Tax Net-to-Gross Bump-up	Pre-Tax Revenue Requirement
Debt	47.74%	4.380%	2.091%		2.091%
Preferred	0.01%	6.750%	0.001%	132.60%	0.001%
Common	52.25%	9.800%	5.121%	132.60%	6.790%
Total	100.00%		7.212%		8.882%

Merged Effective Tax Rate	24.587%
Pre-Tax Bump-up Factor	132.60%

2020 Protocol Allocation Factors

Forecast 2023 SG Factor	26.070%

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	26.070%	(62,000)	8.12.1
Distribution	361	3	(120,000)	OR	Situs	(120,000)	8.11.2
			(357,818)			(182,000)	
Adjustment to Reserve:							
Transmission	108TP	3	17,650	SG	26.070%	4,601	8.12.1
Distribution	108364	3	23,910	OR	Situs	23,910	8.11.2
			41,560			28,512	
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.

PacifiCorp
Oregon General Rate Case - December 2023
Transmission Project Adjustment

Wallula-to-McNary Project

In-Service Date	Jan-19
Depreciation Composite Rate	1.875%

		* Gross Plant	Depreciation Expense	Depreciation Reserve	Net Book Value	
2020	June	62,000	97	(1,695)	60,305	
	July	62,000	97	(1,792)	60,208	
	August	62,000	97	(1,889)	60,111	
	September	62,000	97	(1,986)	60,014	
	October	62,000	97	(2,083)	59,917	
	November	62,000	97	(2,180)	59,820	
	December	62,000	97	(2,277)	59,723	
2021	January	62,000	97	(2,373)	59,627	
	February	62,000	97	(2,470)	59,530	
	March	62,000	97	(2,567)	59,433	
	April	62,000	97	(2,664)	59,336	
	May	62,000	97	(2,761)	59,239	
	June	62,000	97	(2,858)	59,142	
	July	62,000	97	(2,955)	59,045	
	August	62,000	97	(3,051)	58,949	
	September	62,000	97	(3,148)	58,852	
	October	62,000	97	(3,245)	58,755	
	November	62,000	97	(3,342)	58,658	
	December	62,000	97	(3,439)	58,561	
2022	January	62,000	97	(3,536)	58,464	
	February	62,000	97	(3,633)	58,367	
	March	62,000	97	(3,730)	58,270	
	April	62,000	97	(3,826)	58,174	
	May	62,000	97	(3,923)	58,077	
	June	62,000	97	(4,020)	57,980	
	July	62,000	97	(4,117)	57,883	
	August	62,000	97	(4,214)	57,786	
	September	62,000	97	(4,311)	57,689	
	October	62,000	97	(4,408)	57,592	
	November	62,000	97	(4,505)	57,495	
	December	62,000	97	**(4,601)**	57,399	**Ref. 8.12**

* Oregon's allocated amount

PacifiCorp
Oregon General Rate Case - December 2023
Transmission Project Adjustment

Threemile Canyon Project

In-Service Date	Apr-15
Depreciation Composite Rate	2.585%

		Gross Plant	Depreciation Expense	Depreciation Reserve	Net Book Value	
2020	June	120,000	258	(16,155)	103,845	
	July	120,000	258	(16,414)	103,586	
	August	120,000	258	(16,672)	103,328	
	September	120,000	258	(16,931)	103,069	
	October	120,000	258	(17,189)	102,811	
	November	120,000	258	(17,448)	102,552	
	December	120,000	258	(17,706)	102,294	
2021	January	120,000	258	(17,965)	102,035	
	February	120,000	258	(18,223)	101,777	
	March	120,000	258	(18,482)	101,518	
	April	120,000	258	(18,740)	101,260	
	May	120,000	258	(18,999)	101,001	
	June	120,000	258	(19,257)	100,743	
	July	120,000	258	(19,516)	100,484	
	August	120,000	258	(19,774)	100,226	
	September	120,000	258	(20,033)	99,967	
	October	120,000	258	(20,291)	99,709	
	November	120,000	258	(20,550)	99,450	
	December	120,000	258	(20,808)	99,192	
2022	January	120,000	258	(21,067)	98,933	
	February	120,000	258	(21,325)	98,675	
	March	120,000	258	(21,584)	98,416	
	April	120,000	258	(21,842)	98,158	
	May	120,000	258	(22,101)	97,899	
	June	120,000	258	(22,359)	97,641	
	July	120,000	258	(22,618)	97,382	
	August	120,000	258	(22,876)	97,124	
	September	120,000	258	(23,135)	96,865	
	October	120,000	258	(23,393)	96,607	
	November	120,000	258	(23,652)	96,348	
	December	120,000	258	**(23,910)**	96,090	**Ref. 8.12**

PacifiCorp
Oregon General Rate Case - December 2023
Cholla Unit 4 Retirement

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense							
Remove O&M expense	506	1	(14,648,254)	SG	26.070%	(3,818,850)	8.13.1
Add Closure Cost Reg. Asset Amort. Exp	407	3	937,832	SG	26.070%	244,496	8.13.2
Add Property Tax Reg. Asset Amort. Exp	407	3	518,123	OR	Situs	518,123	8.13.3
Adjustment to Rate Base							
Remove M&S Inventory Balance	154	1	(5,341,897)	SG	26.070%	(1,392,651)	8.13.1
Remove Nonunion Severance Reg. Asset	182M	1	(2,700,000)	SG	26.070%	(703,899)	8.13.1
Remove Safe Harbor Lease Reg. Asset	182M	1	(836,167)	SG	26.070%	(217,992)	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
Add Dec. 2023 Cholla Closure Cost	182M	3	2,344,579	SG	26.070%	611,240	8.13.2
Adjustment to Tax:							
Property tax Reg asset amort - Sch M	SCHMAT	3	519,052	OR	Situs	519,052	
Property tax Reg asset amort - Def Inc Tax	41110	3	(127,618)	OR	Situs	(127,618)	
Property tax Reg asset amort - ADIT	283	3	(56,568)	OR	Situs	(56,568)	
Closure Cost Reg asset amort - Sch M	SCHMAT	3	937,832	SG	26.070%	244,496	
Closure Cost Reg asset amort - Def Inc Tax	41110	3	(230,581)	SG	26.070%	(60,113)	
Closure Cost Reg asset amort - ADIT	283	3	(576,453)	SG	26.070%	(150,283)	
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.

PacifiCorp
Oregon General Rate Case - December 2023
Cholla Unit 4 Retirement
Cholla Unit 4 - Non-EPIS Booked Balances

	FERC account	Factor	12 ME June 2021
O&M Expenses	506	SG	$ **14,648,254**
			Ref 8.13

	FERC account		EOP June 2021
Material & Supplies	154	SG	$ **5,341,897**
			Ref 8.13

	FERC account		EOP June 2021
Reg Asset-Cholla U4-Nonunion Severance	182M	SG	$ **2,700,000**
Reg Asset-Cholla U4-Safe Harbor Lease	182M	SG	$ **836,167**
Contra Reg Asset-Cholla U4 Closure-OR	182M	OR	$ **(920,203)**
			Ref 8.13

PacifiCorp
Oregon General Rate Case - December 2023
Cholla Unit 4 Retirement
Treatment of Cholla Unrecovered Closure Items

	Uncrecovered Costs	13 Mo. Avg. Dec 2023	
Safe Harbor Lease Payment	113,495	94,579	**below**
Nonunion Severance	2,700,000	2,250,000	**below**
Total Unrecovered Closure Items	2,813,495	**2,344,579**	
		Ref. 8.13	

	Beg Bal		Amortization				
	Nonunion Severance	Safe Harbor Lease Pmt	Nonunion Severance	Safe Harbor Lease Pmt	Total	End Bal	
Dec-22						2,813,495	**Above**
Jan-23	2,700,000	113,495	(75,000)	(3,153)	(78,153)	2,735,343	
Feb-23	2,625,000	110,343	(75,000)	(3,153)	(78,153)	2,657,190	
Mar-23	2,550,000	107,190	(75,000)	(3,153)	(78,153)	2,579,037	
Apr-23	2,475,000	104,037	(75,000)	(3,153)	(78,153)	2,500,885	
May-23	2,400,000	100,885	(75,000)	(3,153)	(78,153)	2,422,732	
Jun-23	2,325,000	97,732	(75,000)	(3,153)	(78,153)	2,344,579	
Jul-23	2,250,000	94,579	(75,000)	(3,153)	(78,153)	2,266,427	
Aug-23	2,175,000	91,427	(75,000)	(3,153)	(78,153)	2,188,274	
Sep-23	2,100,000	88,274	(75,000)	(3,153)	(78,153)	2,110,121	
Oct-23	2,025,000	85,121	(75,000)	(3,153)	(78,153)	2,031,969	
Nov-23	1,950,000	81,969	(75,000)	(3,153)	(78,153)	1,953,816	
Dec-23	1,875,000	78,816	(75,000)	(3,153)	(78,153)	1,875,663	**13 Mo. Avg.**
			Amort exp. 12 ME Dec-23		**(937,832)**		**2,344,579**
					Ref. 8.13		

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

	12 ME June 2021	12 ME Dec 2023	Difference
Cholla Property Taxes Expense	(299,058)	219,065	**518,123**
			Ref. 8.13

	Date	Beg Bal	Amortization	Interest*	End Bal
	Dec-22				639,589
	Jan-23	639,589	(18,255)	956	622,290
	Feb-23	622,290	(18,255)	930	604,964
	Mar-23	604,964	(18,255)	904	587,612
	Apr-23	587,612	(18,255)	877	570,234
	May-23	570,234	(18,255)	851	552,830
	Jun-23	552,830	(18,255)	825	535,399
	Jul-23	535,399	(18,255)	798	517,942
	Aug-23	517,942	(18,255)	772	500,458
	Sep-23	500,458	(18,255)	745	482,948
	Oct-23	482,948	(18,255)	719	465,411
	Nov-23	465,411	(18,255)	692	447,848
	Dec-23	447,848	(18,255)	665	430,258
Amort exp. 12 months ending December 2023			**(219,065)**		

PacifiCorp
Oregon General Rate Case - December 2023
Cholla Unit 4 Retirement
Treatment of Cholla Property Taxes

Oregon Property Tax Deferral 2021 **639,589**

Date	Beg Bal	Deferral	Interest*	End Bal
Jan-21		52,015	27	52,042
Feb-21	52,042	52,015	81	104,137
Mar-21	104,137	52,015	134	156,287
Apr-21	156,287	52,015	188	208,490
May-21	208,490	52,015	242	260,747
Jun-21	260,747	52,015	296	313,058
Jul-21	313,058	52,015	350	365,423
Aug-21	365,423	52,015	404	417,843
Sep-21	417,843	52,015	459	470,316
Oct-21	470,316	52,015	513	522,844
Nov-21	522,844	52,015	567	575,426
Dec-21	575,426	52,015	621	628,062
Jan-22	628,062	-	953	629,015
Feb-22	629,015	-	954	629,969
Mar-22	629,969	-	955	630,924
Apr-22	630,924	-	957	631,881
May-22	631,881	-	958	632,839
Jun-22	632,839	-	960	633,799
Jul-22	633,799	-	961	634,761
Aug-22	634,761	-	963	635,723
Sep-22	635,723	-	964	636,687
Oct-22	636,687	-	966	637,653
Nov-22	637,653	-	967	638,620
Dec-22	638,620	-	969	**639,589**
				Ref. 8.13.3

*MBT Rate 2021 1.240%
*MBT Rate 2022 1.820%

PacifiCorp
Oregon General Rate Case - December 2023
Wind Project Deferrals Amortization

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Cedar Springs II Amort.	407	3	256,632	OR	Situs	256,632	8.14.1
TB Flats Amort.	407	3	6,140,445	OR	Situs	6,140,445	8.14.4
			6,397,077			6,397,077	
Adjustment to Tax:							
Cedar Springs II Amort - Sch M	SCHMAT	3	256,632	OR	Situs	256,632	
Cedar Springs II Amort - Ditexp	41110	3	(63,096)	OR	Situs	(63,096)	
TB Flats Amort - Sch M	SCHMAT	3	6,140,445	OR	Situs	6,140,445	
TB Flats Amort - Ditexp	41110	3	(1,509,732)	OR	Situs	(1,509,732)	

Description of Adjustment:

This adjustment adds into test period results the amortization of deferred revenue requirement associated with Cedar Springs II wind project, which went into service in December 2020, one month prior to new rates from the 2021 Oregon General Rate Case (GRC) became effective. Cedar Springs II was part of EV 2020 wind projects determined to be prudent in the 2021 GRC (Order 20-473). The Company has a pending application for deferral treatment (Docket No. UM 2134) of the revenue requirement for Cedar Springs II in front of the Commission, for the approximately one month period that the facility is in service and serving customers, but its costs were not yet reflected in customer rates.

This adjustment also adds into test period results the amortization deferred revenue requirement, net of net power cost and production tax credit benefits, associated with TB Flats. TB Flats was also part of the EV 2020 wind projects determined to be prudent in the 2021 GRC. A portion of the project that was complete and in service by 12/30/2021 is already reflected in rates. Upon the completion of the remainder of the project in July 2021, the Company filed a request for deferral treatment of the revenue requirement for TB Flats (Docket No. UM 2186).

This adjustments proposes a three-year amortization period, starting January 1, 2023, for deferred net revenue requirement associated with these wind projects not having been or is being recovered in customer rates.

PacifiCorp
Oregon General Rate Case - December 2023
Wind Project Deferrals Amortization
Cedar Springs II - Amortization Summary

	Amortization
Base Period Amount (below)	-
Pro Forma Amount (below)	256,632
Adjustment:	**256,632**
	Ref. 8.14

In-Service Date 12/8/2020

		Opening Bal.	Accrual[1]	Amortization	Interest[2,3]	Ending Bal.		
	December	-	647,365	-	1,525	648,890		
2021	January	648,890	-	-	3,859	652,749		
	February	652,749	-	-	3,882	656,632		
	March	656,632	-	-	3,905	660,537		
	April	660,537	-	-	3,929	664,466		
	May	664,466	-	-	3,952	668,418		
	June	668,418	-	-	3,976	672,393		
	July	672,393	-	-	3,999	676,392		
	August	676,392	-	-	4,023	680,415		
	September	680,415	-	-	4,047	684,462		
	October	684,462	-	-	4,071	688,533		
	November	688,533	-	-	4,095	692,628		
	December	692,628	-	-	4,120	696,748		
2022	January	696,748	-	-	4,144	700,892		
	February	700,892	-	-	4,169	705,061		
	March	705,061	-	-	4,193	709,254		
	April	709,254	-	-	4,218	713,472		
	May	713,472	-	-	4,243	717,716		
	June	717,716	-	-	4,269	721,985		
	July	721,985	-	-	4,294	726,279		
	August	726,279	-	-	4,320	730,598		
	September	730,598	-	-	4,345	734,944		
	October	734,944	-	-	4,371	739,315		
	November	739,315	-	-	4,397	743,712	**SCHMDT**	**41010**
	December	743,712	-	-	4,423	748,136		
2023	January	748,136	-	21,386	1,151	727,900	21,386	(5,258)
	February	727,900	-	21,386	1,120	707,635	21,386	(5,258)
	March	707,635	-	21,386	1,089	687,338	21,386	(5,258)
	April	687,338	-	21,386	1,059	667,011	21,386	(5,258)
	May	667,011	-	21,386	1,028	646,653	21,386	(5,258)
	June	646,653	-	21,386	997	626,264	21,386	(5,258)
	July	626,264	-	21,386	966	605,844	21,386	(5,258)
	August	605,844	-	21,386	935	585,393	21,386	(5,258)
	September	585,393	-	21,386	904	564,911	21,386	(5,258)
	October	564,911	-	21,386	873	544,398	21,386	(5,258)
	November	544,398	-	21,386	842	523,854	21,386	(5,258)
	December	523,854	-	21,386	811	503,278	21,386	(5,258)
			Pro Forma Amort =	256,632			**256,632**	**(63,096)**
							Ref 8.14	**Ref 8.14**

Note:
1. Ref Page 8.14.2
2. 2020 Interest rate is approved WACC from UE-263. 2021 Interest rate is approved WACC from UE-374.
3. Interest rate in amortization period per UM-1147, MBT Rate, approved January 14, 2022.

PacifiCorp PAGE 8.14.2
Oregon General Rate Case - December 2023
Wind Project Deferrals Amortization
Cedar Springs II Revenue Requirement Summary

		Cedar Springs II Deferral		
		Total Company	**2020 Allocation %**	**Oregon Allocated**
Revenue Requirement	**Factor**			
Capital Investment				
Wind Generation	SG	244,911,084	26.456%	64,793,297
Transmission	SG	81,206,115	26.456%	21,483,764
General	SG	1,389,974	26.456%	367,729
Depreciation Reserve				
Wind Generation	SG	(337,223)	26.456%	(89,215)
Transmission	SG	(59,211)	26.456%	(15,665)
General	SG	(2,029)	26.456%	(537)
Accumulated DIT Balance	SG	(3,173,785)	26.456%	(839,652)
Net Rate Base		323,934,925		85,699,722
Pre-Tax Rate of Return		9.296%		9.296%
Pre-Tax Return on Rate Base		30,111,712		7,966,308
Dec 2020 Pre-Tax Return		2,509,309		663,859
Operation & Maintenance	SG	135,552	26.456%	35,861
Depreciation				
Wind Generation	SG	337,223	26.456%	89,215
Transmission	SG	59,211	26.456%	15,665
General	SG	2,029	26.456%	537
Deferred Income Tax Expense	SG	4	26.456%	1
Property Taxes	GPS	246,537	27.337%	67,397
Dec 2020 Rev. Reqt. Before Gross-up		33,401,577		872,535
Revenue Requirement for Deferral (12/8/2020 - 12/31/2020)				**647,365**

PacifiCorp
Oregon General Rate Case - December 2023
Wind Project Deferrals Amortization
Cedar Springs II Wind Project Capital Additions
Deferral Application - UM 2134

In-Service Date Dec-20

Cedar Springs Wind Project 200 MW 2020

	Gross Plant In Service		
	Wind Generation	Transmission	General
Dec-20	244,911,084	22,842,576	1,375,138

	Accumulated Depreciation		
	Wind Generation	Transmission	General
Dec-20	(337,223)	(16,656)	(2,007)

	Depreciation Expense		
	Wind Generation	Transmission	General
Dec-20	337,223	16,656	2,007
Depreciation Rate	*3.305%*	*1.750%*	*3.503%*

	O&M Expenses
Dec-20	135,552

Q712 Cedar Springs Wind 1

	Gross Plant In Service	
	Transmission	General
Dec-20	58,363,539	14,836

	Accumulated Reserves	
	Transmission	General
Dec-20	(42,555)	(22)

	Depreciation Expense	
	Transmission	General
Dec-20	42,555	22
Depreciation Rate	*1.750%*	*3.503%*

	Tax: Wind and Transmission				
	SCHMAT	SCHMDT	Def Inc Tax Exp	Flow-thru	ADIT
Dec-20	398,463	(13,309,827)	3,174,466	4	(3,173,785)

PacifiCorp
Oregon General Rate Case - December 2023
Wind Project Deferrals Amortization
TB Flats - Amortization Summary

	Amortization
Base Period Amount (below)	-
Pro Forma Amount (below)	6,140,445
Adjustment:	**6,140,445**
	Ref. 8.14

In-Service Date 7/26/2021

		Opening Bal.	Accrual[1]	Amortization	Interest[2,3]	Ending Bal.	SCHMDT	41010
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	511,704	(125,811)
	February	17,416,496	-	511,704	26,803	16,931,595	511,704	(125,811)
	March	16,931,595	-	511,704	26,068	16,445,959	511,704	(125,811)
	April	16,445,959	-	511,704	25,331	15,959,587	511,704	(125,811)
	May	15,959,587	-	511,704	24,593	15,472,476	511,704	(125,811)
	June	15,472,476	-	511,704	23,855	14,984,627	511,704	(125,811)
	July	14,984,627	-	511,704	23,115	14,496,038	511,704	(125,811)
	August	14,496,038	-	511,704	22,374	14,006,708	511,704	(125,811)
	September	14,006,708	-	511,704	21,632	13,516,636	511,704	(125,811)
	October	13,516,636	-	511,704	20,888	13,025,820	511,704	(125,811)
	November	13,025,820	-	511,704	20,144	12,534,261	511,704	(125,811)
	December	12,534,261	-	511,704	19,398	12,041,955	511,704	(125,811)
			Pro Forma Amort =	6,140,445			**6,140,445**	**(1,509,732)**

Note:
1. Ref Page 8.14.5
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
Wind Project Deferrals Amortization
TB Flats Revenue Requirement Summary

		TB Flats Deferral - Year 1		
		Total Company	2021 Allocation %	Oregon Allocated
Revenue Requirement	**Factor**			
Capital Investment				
Wind Generation	SG	401,588,103	26.023%	104,503,797
Transmission	SG	46,176,918	26.023%	12,016,450
General	SG	1,507,051	26.023%	392,174
Depreciation Reserve				
Wind Generation	SG	(16,092,843)	26.023%	(4,187,781)
Transmission	SG	(974,922)	26.023%	(253,700)
General	SG	(57,399)	26.023%	(14,937)
Accumulated DIT Balance	SG	(17,812,765)	26.023%	(4,635,350)
Net Rate Base		414,334,144		107,820,652
Pre-Tax Rate of Return		8.686%		8.686%
Pre-Tax Return on Rate Base		35,989,339		9,365,373
NPC/PTC Benefits	OR	(3,814,062)	100.000%	(3,814,062)
Depreciation				
Wind Generation	SG	19,457,695	26.023%	5,063,404
Transmission	SG	865,794	26.023%	225,302
General	SG	51,546	26.023%	13,414
Deferred Income Tax Expense	SG	156,816	26.023%	40,808
Annual Rev. Reqt. Before Gross-up		52,707,128		10,894,240
Monthly Rev. Reqt. Before Gross-up				**907,853**
				Ref 8.14.4

		TB Flats Deferral - Year 2		
		Total Company	2021 Allocation %	Oregon Allocated
Revenue Requirement	**Factor**			
Capital Investment				
Wind Generation	SG	405,463,030	26.023%	105,512,155
Transmission	SG	46,176,918	26.023%	12,016,450
General	SG	1,507,051	26.023%	392,174
Depreciation Reserve				
Wind Generation	SG	(35,687,599)	26.023%	(9,286,853)
Transmission	SG	(1,407,819)	26.023%	(366,352)
General	SG	(83,172)	26.023%	(21,643)
Accumulated DIT Balance	SG	(41,794,183)	26.023%	(10,875,947)
Net Rate Base		374,174,227		97,369,984
Pre-Tax Rate of Return		8.686%		8.686%
Pre-Tax Return on Rate Base		32,501,022		8,457,622
NPC/PTC Benefits*	OR	-	26.023%	-
Depreciation				
Wind Generation	SG	19,613,230	26.023%	5,103,879
Transmission	SG	865,794	26.023%	225,302
General	SG	51,546	26.023%	13,414
Deferred Income Tax Expense	SG	156,816	26.023%	40,808
Annual Rev. Reqt. Before Gross-up		53,188,408		13,841,024
Monthly Rev. Reqt. Before Gross-up				**1,153,419**
				Ref 8.14.4

**CY 2022 TAM reflects full NPC/PTC benefit of TB Flats being online - no adjustment required*

PacifiCorp
Oregon General Rate Case - December 2023
Wind Project Deferrals Amortization
TB Flats Wind Project Capital Additions
Deferral Application - UM 2186

In-Service Date Jul-21

Year 1 - July 2021 through July 2022

	Gross Plant In Service			Accumulated Depreciation				Depreciation Expense		
	Wind*	**Trans.**	**General**	**Wind**	**Trans.**	**General**		**Wind**	**Trans.**	**General**
Jul-21	381,883,656	46,176,918	1,507,051	(6,423,289)	(542,025)	(31,626)	Jul-21	1,477,678	72,150	4,295
Aug-21	386,245,687	46,176,918	1,507,051	(7,971,467)	(614,174)	(35,922)	Aug-21	1,548,178	72,150	4,295
Sep-21	397,900,696	46,176,918	1,507,051	(9,551,928)	(686,324)	(40,217)	Sep-21	1,580,461	72,150	4,295
Oct-21	405,453,030	46,176,918	1,507,051	(11,171,102)	(758,473)	(44,513)	Oct-21	1,619,174	72,150	4,295
Nov-21	405,458,030	46,176,918	1,507,051	(12,805,508)	(830,623)	(48,808)	Nov-21	1,634,406	72,150	4,295
Dec-21	405,463,030	46,176,918	1,507,051	(14,439,933)	(902,772)	(53,104)	Dec-21	1,634,426	72,150	4,295
Jan-22	405,463,030	46,176,918	1,507,051	(16,074,369)	(974,922)	(57,399)	Jan-22	1,634,436	72,150	4,295
Feb-22	405,463,030	46,176,918	1,507,051	(17,708,805)	(1,047,071)	(61,694)	Feb-22	1,634,436	72,150	4,295
Mar-22	405,463,030	46,176,918	1,507,051	(19,343,241)	(1,119,221)	(65,990)	Mar-22	1,634,436	72,150	4,295
Apr-22	405,463,030	46,176,918	1,507,051	(20,977,677)	(1,191,370)	(70,285)	Apr-22	1,634,436	72,150	4,295
May-22	405,463,030	46,176,918	1,507,051	(22,612,112)	(1,263,520)	(74,581)	May-22	1,634,436	72,150	4,295
Jun-22	405,463,030	46,176,918	1,507,051	(24,246,548)	(1,335,669)	(78,876)	Jun-22	1,634,436	72,150	4,295
Jul-22	405,463,030	46,176,918	1,507,051	(25,880,984)	(1,407,819)	(83,172)	Jul-22	1,634,436	72,150	4,295
13 Mo. Avg.	**401,588,103**	**46,176,918**	**1,507,051**	**(16,092,843)**	**(974,922)**	**(57,399)**	**12-mo ending**	**19,457,695**	**865,794**	**51,546**
							Depreciation Rate	*4.837%*	*1.875%*	*3.420%*

Year 2 - July 2022 through July 2023

	Gross Plant In Service			Accumulated Depreciation				Depreciation Expense		
	Wind	**Trans.**	**General**	**Wind**	**Trans.**	**General**		**Wind**	**Trans.**	**General**
Jul-22	405,463,030	46,176,918	1,507,051	(25,880,984)	(1,407,819)	(83,172)	Jul-22	1,634,436	72,150	4,295
Aug-22	405,463,030	46,176,918	1,507,051	(27,515,420)	(1,407,819)	(83,172)	Aug-22	1,634,436	72,150	4,295
Sep-22	405,463,030	46,176,918	1,507,051	(29,149,856)	(1,407,819)	(83,172)	Sep-22	1,634,436	72,150	4,295
Oct-22	405,463,030	46,176,918	1,507,051	(30,784,291)	(1,407,819)	(83,172)	Oct-22	1,634,436	72,150	4,295
Nov-22	405,463,030	46,176,918	1,507,051	(32,418,727)	(1,407,819)	(83,172)	Nov-22	1,634,436	72,150	4,295
Dec-22	405,463,030	46,176,918	1,507,051	(34,053,163)	(1,407,819)	(83,172)	Dec-22	1,634,436	72,150	4,295
Jan-23	405,463,030	46,176,918	1,507,051	(35,687,599)	(1,407,819)	(83,172)	Jan-23	1,634,436	72,150	4,295
Feb-23	405,463,030	46,176,918	1,507,051	(37,322,035)	(1,407,819)	(83,172)	Feb-23	1,634,436	72,150	4,295
Mar-23	405,463,030	46,176,918	1,507,051	(38,956,470)	(1,407,819)	(83,172)	Mar-23	1,634,436	72,150	4,295
Apr-23	405,463,030	46,176,918	1,507,051	(40,590,906)	(1,407,819)	(83,172)	Apr-23	1,634,436	72,150	4,295
May-23	405,463,030	46,176,918	1,507,051	(42,225,342)	(1,407,819)	(83,172)	May-23	1,634,436	72,150	4,295
Jun-23	405,463,030	46,176,918	1,507,051	(43,859,778)	(1,407,819)	(83,172)	Jun-23	1,634,436	72,150	4,295
Jul-23	405,463,030	46,176,918	1,507,051	(45,494,214)	(1,407,819)	(83,172)	Jul-23	1,634,436	72,150	4,295
13 Mo. Avg.	**405,463,030**	**46,176,918**	**1,507,051**	**(35,687,599)**	**(1,407,819)**	**(83,172)**	**12-mo ending**	**19,613,230**	**865,794**	**51,546**

*Gross plant excludes portion of TB Flats that was included in rates effective 1/1/2021

PacifiCorp
Oregon General Rate Case - December 2023
Wind Project Deferrals Amortization
TB Flats Wind Project Tax Balances Summary

In-Service Date Jul-21

Tax: Wind and Transmission	Tax SCHMAT	Tax SCHMDT	Def Inc Tax Exp	Flow-thru	ADIT
Jul-21	1,554,123	(19,340,076)	4,372,961	6,534	(3,035,199)
Aug-21	1,624,623	(19,667,228)	4,436,063	13,068	(7,484,330)
Sep-21	1,656,906	(17,918,977)	3,998,290	13,068	(11,495,689)
Oct-21	1,695,619	(6,210,154)	1,109,971	13,068	(12,618,728)
Nov-21	1,710,851	(6,210,154)	1,106,226	13,068	(13,738,022)
Dec-21	1,710,871	(6,210,154)	1,106,221	13,068	(14,857,311)
Jan-22	1,710,881	(11,003,046)	2,284,627	13,068	(17,155,007)
Feb-22	1,710,881	(11,003,046)	2,284,627	13,068	(19,452,703)
Mar-22	1,710,881	(11,003,046)	2,284,627	13,068	(21,750,399)
Apr-22	1,710,881	(11,003,046)	2,284,627	13,068	(24,048,095)
May-22	1,710,881	(11,003,046)	2,284,627	13,068	(26,345,791)
Jun-22	1,710,881	(11,003,046)	2,284,627	13,068	(28,643,487)
Jul-22	1,710,881	(11,003,046)	2,284,627	13,068	(30,941,183)
12-mo ending	**20,375,035**	**(133,237,989)**	**27,749,160**	**156,816**	
				13-mo average	**(17,812,765)**

Tax: Wind and Transmission	Tax SCHMAT	Tax SCHMDT	Def Inc Tax Exp	Flow-thru	ADIT
Jul-22	1,710,881	(11,003,046)	2,284,627	13,068	(30,941,183)
Aug-22	1,710,881	(11,003,046)	2,284,627	13,068	(33,238,879)
Sep-22	1,710,881	(11,003,046)	2,284,627	13,068	(35,536,575)
Oct-22	1,710,881	(11,003,046)	2,284,627	13,068	(37,834,271)
Nov-22	1,710,881	(11,003,046)	2,284,627	13,068	(40,131,967)
Dec-22	1,710,881	(11,003,046)	2,284,627	13,068	(42,429,662)
Jan-23	1,710,881	(6,715,121)	1,230,373	13,068	(43,567,494)
Feb-23	1,710,881	(6,715,121)	1,230,373	13,068	(44,609,939)
Mar-23	1,710,881	(6,715,121)	1,230,373	13,068	(45,546,778)
Apr-23	1,710,881	(6,715,121)	1,230,373	13,068	(46,381,416)
May-23	1,710,881	(6,715,121)	1,230,373	13,068	(47,110,446)
Jun-23	1,710,881	(6,715,121)	1,230,373	13,068	(47,737,276)
Jul-23	1,710,881	(6,715,121)	1,230,373	13,068	(48,258,498)
12-mo ending	**20,530,570**	**(102,021,077)**	**20,035,746**	**156,816**	
				13-mo average	**(41,794,183)**

PacifiCorp
Oregon General Rate Case - December 2021
Wind Project Deferrals Amortization
TB Flats - NPC/PTC Benefits Pro-ration

PAGE 8.14.8

	TB Flats
Actual Online Date	7/27/2021
2021 TAM Online Date	6/30/2021
EV2020 TAM Benefit (TB Flats & Pryor Mountain)	$ (6,410,832) [1]
TB Flats Proration	69.66%
2021 TAM - Days in Service	185
Daily Benefit in 2021 TAM	$ (24,140)
Actual Days in Service	158
Benefit Adjustment (Rate Decrease)	$ (3,814,062)

Proration for Rate Update	Increased MWh[2]	
Pryor Mountain	132,754,459	30.34%
TB Flats II	304,811,858	69.66%
	437,566,317	100.00%

Footnotes:
1 Benefit represents Oregon allocated dollar amount as quantified in 2021 TAM.
2 Increased in generation forecasted in TAM with Pryor Mountain & TB Flats II being fully online.
2021 TAM assumed 6/30/2021 full online date.

PacifiCorp
Oregon General Rate Case - December 2023
Wind Project Deferrals Amortization
Revenue Requirement Variables

Capital Cost and Structure
From Oregon Results of Operations 12 ME Dec 2018
Reference UE-369, PAC/404 - Oregon 2020 Renewable Adjustment Clause

	Capital Structure	Embedded Cost	Weighted Cost	Pre-Tax Bump-up	Pre-Tax Revenue Requirement
Debt	47.89%	5.27%	2.525%		2.525%
Preferred	0.02%	6.75%	0.001%	132.60%	0.002%
Common	52.09%	9.80%	5.105%	132.60%	6.769%
Total	100.00%		7.631%		9.296%

Merged Effective Tax Rate	24.587%
Tax Gross-up factor for PTC = (1/(1 - tax rate))	132.60%

2017 Protocol Allocation Factors

Forecast 2020 SG Factor [1]	26.4558%
Oregon GPS Factor [2]	27.3374%

Property Tax Calculation

Total Company	151,139,518
Oregon GPS Factor [2]	27.3374%
Oregon Property Taxes	41,317,669
Oregon Gross EPIS	7,699,300,653
Oregon Accum. Depr.	(2,979,098,163)
Oregon Accum. Amort.	(171,186,979)
Oregon Net EPIS	4,549,015,511
Estimated Oregon Property Tax Rate	0.908%

Capital Cost and Structure
Ordered from Oregon 2021 General Rate Case
Reference UE-374, Compliance Filing

	Capital Structure	Embedded Cost	Weighted Cost	Pre-Tax Bump-up	Pre-Tax Revenue Requirement
Debt	49.99%	4.77%	2.387%		2.387%
Preferred	0.01%	6.75%	0.001%	1.326	0.001%
Common	50.00%	9.50%	4.750%	1.326	6.299%
TOTAL			7.137%		8.686%

Merged Effective Tax Rate	24.587%
Tax Gross-up factor for PTC = (1/(1 - tax rate))	132.60%

2020 Protocol Allocation Factors

Approved 2021 SG Factor [3]	26.0226%

Footnotes:
1 SG Factor from 2020 TAM filing
2 Results of Operations, December 2018, Page 9.2
3 Oregon General Rate Case Docket No. UE 374 Compliance Filing Jurisdictional Allocation Model (JAM)

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	(29,210,086)	SE	25.068%	(7,322,424)	8.15.1
1 - Fuel Stock - Working Capital Deposit	25316	3	3,000	SE	25.068%	752	8.15.1
1 - Fuel Stock - Working Capital Deposit	25317	3	34,169	SE	25.068%	8,566	8.15.1
2 - Prepaid Overhauls	186M	3	(16,949,013)	SG	26.070%	(4,418,666)	8.15.1

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 an increase 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.

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	47,165,373	13,000,966	
Cholla	151	SE	(0)	(0)	-	
Colstrip	151	SE	1,907,941	2,019,347	111,406	
Craig	151	SE	611,228	3,609,917	2,998,689	
Hayden	151	SE	4,236,263	1,946,527	(2,289,736)	
Hunter	151	SE	71,160,227	47,584,144	(23,576,084)	
Huntington	151	SE	23,856,872	20,802,902	(3,053,970)	
Dave Johnston	151	SE	11,802,796	9,993,677	(1,809,119)	
Naughton	151	SE	24,588,118	9,995,879	(14,592,238)	
Rock Garden	151	SE	31,430,017	31,430,017	-	
Total			203,757,869	174,547,782	**(29,210,086)**	**Ref. 8.15**

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**
DPEC Working Capital Deposit	25317	SE	(2,675,522)	(2,641,353)	**34,169**	**Ref. 8.15**

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**

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	26.070%	(3,008,271)	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	26.070%	(899,080)	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	26.070%	118,044	

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.

PacifiCorp
Oregon General Rate Case - December 2023
Carbon Plant Closure

On January 1, 2014 new depreciation rates for the Carbon Plant became effective in Utah, Idaho, and Wyoming. The difference in the depreciation in these rates due to the retirement of the Carbon Plant was deferred in those states, to be amortized to expense after the plant was retired. This deferral and amortization of depreciation expense was booked on a company system factor. It should have been allocated situs to Utah, Idaho, and Wyoming, as appropriate. The accounting detail is provided below.

Year	Posting period	Account Number	Amount	Text	FERC Account	FERC Location	Actual Allocation
2020	7	565131	39,887	Amortize ID Deferred Carbon Depreciation	4032000	106	SG
2020	7	565131	96,516	Amortize WY Deferred Carbon Depreciation	4032000	114	SG
2020	7	565131	287,053	Amortize UT Deferred Carbon Depreciation	4032000	109	SG
2020	7	565131	37,209	Amortize WY Deferred Carbon Decomm	4032000	114	SG
2020	8	565131	39,887	Amortize ID Deferred Carbon Depreciation	4032000	106	SG
2020	8	565131	96,516	Amortize WY Deferred Carbon Depreciation	4032000	114	SG
2020	8	565131	287,053	Amortize UT Deferred Carbon Depreciation	4032000	109	SG
2020	8	565131	37,209	Amortize WY Deferred Carbon Decomm	4032000	114	SG
2020	9	565131	39,887	Amortize ID Deferred Carbon Depreciation	4032000	106	SG
2020	9	565131	96,516	Amortize WY Deferred Carbon Depreciation	4032000	114	SG
2020	9	565131	287,053	Amortize UT Deferred Carbon Depreciation	4032000	109	SG
2020	9	565131	37,209	Amortize WY Deferred Carbon Decomm	4032000	114	SG
2020	10	565131	39,887	Amortize ID Deferred Carbon Depreciation	4032000	106	SG
2020	10	565131	96,516	Amortize WY Deferred Carbon Depreciation	4032000	114	SG
2020	10	565131	287,053	Amortize UT Deferred Carbon Depreciation	4032000	109	SG
2020	10	565131	37,209	Amortize WY Deferred Carbon Decomm	4032000	114	SG
2020	11	565131	39,887	Amortize ID Deferred Carbon Depreciation	4032000	106	SG
2020	11	565131	96,516	Amortize WY Deferred Carbon Depreciation	4032000	114	SG
2020	11	565131	287,053	Amortize UT Deferred Carbon Depreciation	4032000	109	SG
2020	11	565131	37,209	Amortize WY Deferred Carbon Decomm	4032000	114	SG
2020	12	565131	37,209	Amortize WY Deferred Carbon Decomm	4032000	114	SG
2020	12	565131	96,516	Amortize WY Deferred Carbon Depreciation	4032000	114	SG
2020	12	565131	287,053	Amortize UT Deferred Carbon Depreciation	4032000	109	SG
2020	12	565131	39,887	Amortize ID Deferred Carbon Depreciation	4032000	106	SG
2020	12	565131	8,775,068	Buy down Utah deferred decomm	4032000	109	SG
			11,539,055				

PacifiCorp
Oregon General Rate Case - December 2023
Carbon Plant Closure
Closing Costs in Pro Forma Period

This amortization schedule of the excess decomissioning costs, net of obsolete materials and supplies, over a five -year period was approved in the Company's general rate case Docket No. UE374, in Order 20-473.

Closure Cost	Total Company	*Allocation	OR Allocated
M&S Obsolete Inventory	3,448,669	26.023%	897,435
Decommissioning Reserve			(8,976,188)
Total Closure Cost			(8,078,754)

*Allocation on approved SG factor from UE-374 OR GRC

Date	Beg Bal	Amortization	End Bal	
Dec-20			(8,976,188)	
Jan-21	(8,976,188)	149,603	(8,826,585)	
Feb-21	(8,826,585)	149,603	(8,676,982)	
Mar-21	(8,676,982)	149,603	(8,527,379)	
Apr-21	(8,527,379)	149,603	(8,377,776)	
May-21	(8,377,776)	149,603	(8,228,173)	
Jun-21	(8,228,173)	149,603	(8,078,569)	
Jul-21	(8,078,569)	149,603	(7,928,966)	
Aug-21	(7,928,966)	149,603	(7,779,363)	
Sep-21	(7,779,363)	149,603	(7,629,760)	
Oct-21	(7,629,760)	149,603	(7,480,157)	
Nov-21	(7,480,157)	149,603	(7,330,554)	
Dec-21	(7,330,554)	149,603	(7,180,951)	
Jan-22	(7,180,951)	149,603	(7,031,347)	
Feb-22	(7,031,347)	149,603	(6,881,744)	
Mar-22	(6,881,744)	149,603	(6,732,141)	
Apr-22	(6,732,141)	149,603	(6,582,538)	
May-22	(6,582,538)	149,603	(6,432,935)	
Jun-22	(6,432,935)	149,603	(6,283,332)	
Jul-22	(6,283,332)	149,603	(6,133,729)	
Aug-22	(6,133,729)	149,603	(5,984,125)	
Sep-22	(5,984,125)	149,603	(5,834,522)	
Oct-22	(5,834,522)	149,603	(5,684,919)	
Nov-22	(5,684,919)	149,603	(5,535,316)	
Dec-22	(5,535,316)	149,603	(5,385,713)	
Jan-23	(5,385,713)	149,603	(5,236,110)	
Feb-23	(5,236,110)	149,603	(5,086,507)	
Mar-23	(5,086,507)	149,603	(4,936,904)	
Apr-23	(4,936,904)	149,603	(4,787,300)	
May-23	(4,787,300)	149,603	(4,637,697)	
Jun-23	(4,637,697)	149,603	(4,488,094)	
Jul-23	(4,488,094)	149,603	(4,338,491)	
Aug-23	(4,338,491)	149,603	(4,188,888)	
Sep-23	(4,188,888)	149,603	(4,039,285)	
Oct-23	(4,039,285)	149,603	(3,889,682)	
Nov-23	(3,889,682)	149,603	(3,740,078)	13MA Bal.
Dec-23	(3,740,078)	149,603	(3,590,475)	(4,488,094)
Amort exp. 12 months ending Dec. 2023		**1,795,238**	**below**	

Net Rate Base Reduction	**(4,039,377)**	**Ref 8.16**
12 ME June-21 Amort. Exp	**89,744**	
12 ME Dec-23 Amort. Exp.	**1,615,751**	**above**
Adjustment	**1,705,494**	**Ref 8.16**

Date	Beg Bal	Amortization	End Bal		Tax Impacts: SCHMDT	41010	ADIT - 190
Dec-20			897,435				1,986,291
Jan-21	897,435	(14,957)	882,477		134,646	33,105	1,953,186
Feb-21	882,477	(14,957)	867,520		134,646	33,105	1,920,081
Mar-21	867,520	(14,957)	852,563		134,646	33,105	1,886,976
Apr-21	852,563	(14,957)	837,606		134,646	33,105	1,853,871
May-21	837,606	(14,957)	822,648		134,646	33,105	1,820,766
Jun-21	822,648	(14,957)	807,691		134,646	33,105	1,787,661
Jul-21	807,691	(14,957)	792,734		134,646	33,105	1,754,556
Aug-21	792,734	(14,957)	777,777		134,646	33,105	1,721,451
Sep-21	777,777	(14,957)	762,819		134,646	33,105	1,688,346
Oct-21	762,819	(14,957)	747,862		134,646	33,105	1,655,241
Nov-21	747,862	(14,957)	732,905		134,646	33,105	1,622,136
Dec-21	732,905	(14,957)	717,948		134,646	33,105	1,589,031
Jan-22	717,948	(14,957)	702,990		134,646	33,105	1,555,926
Feb-22	702,990	(14,957)	688,033		134,646	33,105	1,522,821
Mar-22	688,033	(14,957)	673,076		134,646	33,105	1,489,716
Apr-22	673,076	(14,957)	658,119		134,646	33,105	1,456,611
May-22	658,119	(14,957)	643,161		134,646	33,105	1,423,506
Jun-22	643,161	(14,957)	628,204		134,646	33,105	1,390,401
Jul-22	628,204	(14,957)	613,247		134,646	33,105	1,357,296
Aug-22	613,247	(14,957)	598,290		134,646	33,105	1,324,191
Sep-22	598,290	(14,957)	583,332		134,646	33,105	1,291,086
Oct-22	583,332	(14,957)	568,375		134,646	33,105	1,257,981
Nov-22	568,375	(14,957)	553,418		134,646	33,105	1,224,876
Dec-22	553,418	(14,957)	538,461		134,646	33,105	1,191,771
Jan-23	538,461	(14,957)	523,503		134,646	33,105	1,158,666
Feb-23	523,503	(14,957)	508,546		134,646	33,105	1,125,561
Mar-23	508,546	(14,957)	493,589		134,646	33,105	1,092,456
Apr-23	493,589	(14,957)	478,632		134,646	33,105	1,059,351
May-23	478,632	(14,957)	463,675		134,646	33,105	1,026,246
Jun-23	463,675	(14,957)	448,717		134,646	33,105	993,141
Jul-23	448,717	(14,957)	433,760		134,646	33,105	960,036
Aug-23	433,760	(14,957)	418,803		134,646	33,105	926,931
Sep-23	418,803	(14,957)	403,846		134,646	33,105	893,826
Oct-23	403,846	(14,957)	388,888		134,646	33,105	860,721
Nov-23	388,888	(14,957)	373,931	13MA Bal.	134,646	33,105	827,616
Dec-23	373,931	(14,957)	358,974	448,717	134,646	33,105	794,511
Amort exp. 12 months ending Dec. 2023		**(179,487)**	**below**				

ADIT 13MA Bal.	SCHMDT	41010
993,141	**1,705,494**	**(419,323)**
Ref. 8.16	**Ref. 8.16**	**Ref. 8.16**

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	26.070%	(23,424,771)	
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)			(63,974,678)	8.17.1
Adjustment to Depreciation Reserve:							
Transmission Plant	108TP	1	755,195	SG	26.070%	196,882	
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			802,349	8.17.1
Adjustment to Tax:							
Schedule M Deduction - SG - Tax Depr	SCHMDT	1	(8,535,960)	SG	26.070%	(2,225,354)	
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)			(5,152,646)	
Deferred Inc Tax Exp - SG - Tax Depr	41010	1	(2,098,702)	SG	26.070%	(547,139)	
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)			(1,266,861)	
ADIT - SG	282	1	2,632,090	SG	26.070%	686,195	
ADIT - OR	282	1	753,915	OR	Situs	753,915	
ADIT - CA	282	1	153,510	CA	Situs	-	
			3,539,515			1,440,110	

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.

PacifiCorp
Oregon General Rate Case - December 2023
Remove Labor Day Wildfire Restoration
Base Period Capital Project Balances

Capital Placed In-Service - EOP June 2021

Project	State	Function	Factor	EOP Jun-21
Archie Creek Fire Damage Repair	OR	Distribution	OR	13,737,335
Archie Creek Fire Damage Repair	OR	Transmission	SG	27,270,264
Slater Fire (Happy Camp) Fire Damage	CA	Distribution	CA	9,031,995
Slater Fire (Happy Camp) Fire Damage	OR	Distribution	OR	2,048,231
Slater Fire (Happy Camp) Fire Damage	CA	Transmission	SG	39,742,224
Slater Fire (Happy Camp) Fire Damage	OR	Transmission	SG	1,021,952
Almeda Fire Damage Repair	OR	Distribution	OR	5,827,614
Almeda Fire Damage Repair	OR	General	SO	-
Almeda Fire Damage Repair	OR	Transmission	SG	970,516
Beachie Creek Fire Damage Repair	OR	Distribution	OR	2,520,677
Two Four Two Fire Damage Repair	OR	Transmission	SG	16,054
Two Four Two Fire Damage Repair	OR	Distribution	OR	6,260,467
S. Obenchain Fire Damage Repair	OR	Transmission	SG	70,242
S. Obenchain Fire Damage Repair	OR	Distribution	OR	503,891
Echo Mountain Fire Damage Repair	OR	Distribution	OR	9,651,692
Echo Mountain Fire Damage Repair	OR	Transmission	SG	20,760,931
Total				**139,434,083**
				Ref 8.17

Accumulated Depreciation Reseve

Project	State	Function	Factor	EOP Jun-21
Archie Creek Fire Damage Repair	OR	Distribution	OR	(233,903)
Archie Creek Fire Damage Repair	OR	Transmission	SG	(282,887)
Slater Fire (Happy Camp) Fire Damage	CA	Distribution	CA	(153,156)
Slater Fire (Happy Camp) Fire Damage	OR	Distribution	OR	(8,657)
Slater Fire (Happy Camp) Fire Damage	CA	Transmission	SG	(430,809)
Slater Fire (Happy Camp) Fire Damage	OR	Transmission	SG	(6,274)
Almeda Fire Damage Repair	OR	Distribution	OR	(66,189)
Almeda Fire Damage Repair	OR	General	SO	-
Almeda Fire Damage Repair	OR	Transmission	SG	(10,666)
Beachie Creek Fire Damage Repair	OR	Distribution	OR	(46,608)
Two Four Two Fire Damage Repair	OR	Transmission	SG	(133)
Two Four Two Fire Damage Repair	OR	Distribution	OR	(112,789)
S. Obenchain Fire Damage Repair	OR	Transmission	SG	(1,446)
S. Obenchain Fire Damage Repair	OR	Distribution	OR	(6,863)
Echo Mountain Fire Damage Repair	OR	Distribution	OR	(130,460)
Echo Mountain Fire Damage Repair	OR	Transmission	SG	(22,980)
Total				**(1,513,819)**
				Ref 8.17

Tab 7 - Bwl_kga CAB

OREGON
ANNUAL EMBEDDED COSTS
Twelve Months Ending December 31, 2023
YEAR END BALANCE

Company Owned Hydro - West

Account	Description	Amount	Mwh	$/Mwh	Differential
535 - 545	Hydro Operation & Maintenance Expense	35,671,725			
403HP	Hydro Depreciation Expense	24,769,019			
404IP / 404HP	Hydro Relicensing Amortization	3,070,608			
	Total West Hydro Operating Expense	**63,511,353**			
330 - 336	Hydro Electric Plant in Service	1,011,178,647			
302 & 182M	Hydro Relicensing	177,482,844			
108HP	Hydro Accumulated Depreciation Reserve	(432,579,140)			
111IP	Hydro Relicensing Accumulated Reserve	(118,482,024)			
154	Materials and Supplies	7,954			
	West Hydro Net Rate Base	**637,608,281**			
	Pre-tax Return	8.88%			
	Rate Base Revenue Requirement	**56,631,184**			
	Annual Embedded Cost				
	West Hydro-Electric Resources	**120,142,537**	3,261,314	36.84	(44,885,867)

Mid C Contracts

Account	Description	Amount	Mwh	$/Mwh	Differential
555	Annual Mid-C Contracts Costs	2,265,569	93,452	24.24	(2,463,291)
	Grant Reasonable Portion	-			-
		2,265,569			(2,463,291)

Qualified Facilities

Account	Description	Amount	Mwh	$/Mwh	Differential
555	Utah Annual Qualified Facilities Costs				
555	Oregon Annual Qualified Facilities Costs				
555	Idaho Annual Qualified Facilities Costs				
555	WYU Annual Qualified Facilities Costs				
555	WYP Annual Qualified Facilities Costs				
555	California Annual Qualified Facilities Costs				
555	Washington Annual Qualified Facilities Costs				
	Total Qualified Facilities Costs	-	-		-

All Other Generation Resources
(Excl. West Hydro, Mid C, and QF)

Account	Description	Amount	Mwh	$/Mwh
500 - 514	Steam Operation & Maintenance Expense	934,375,741		
535 - 545	East Hydro Operation & Maintenance Expense	10,657,563		
546 - 554	Other Generation Operation & Maintenance Expense	50,781,968		
555	Other Purchased Power Contracts	0		
40910	Production Tax Credit	0		
4118	SO2 Emission Allowances	(47)		
456	James River / Little Mountain Offset	0		
456	REC Revenues	0		
403SP	Steam Depreciation Expense	275,464,212		
403HP	East Hydro Depreciation Expense	10,129,580		
403OP	Other Generation Depreciation Expense	12,052,676		
403MP	Mining Depreciation Expense	0		
404IP	East Hydro Relicensing Amortization	328,490		
406	Amortization of Plant Acquisition Costs	0		
	Total All Other Operating Expenses	**1,293,790,182**		
310 - 316	Steam Electric Plant in Service	6,873,501,850		
330 - 336	East Hydro Electric Plant in Service	222,560,115		
302 & 186M	East Hydro Relicensing	10,223,926		
340 - 346	Other Electric Plant in Service	269,160,334		
399	Mining	50,741,701		
108SP	Steam Accumulated Depreciation Reserve	(4,673,052,979)		
108OP	Other Generation Accumulated Depreciation Reserve	(142,858,162)		
108MP	Other Accumulated Depreciation Reserve	0		
108HP	East Hydro Accumulated Depreciation Reserve	(105,983,333)		
111IP	East Hydro Relicensing Accumulated Reserve	(6,359,021)		
114	Electric Plant Acquisition Adjustment	141,186,242		
115	Accumulated Provision Acquisition Adjustment	(137,303,921)		
151	Fuel Stock	176,033,332		
253.16 - 253.19	Joint Owner WC Deposit	(5,717,354)		
253.98	SO2 Emission Allowances	0		
154	Materials & Supplies	85,247,211		
154	East Hydro Materials & Supplies			
	Total Net Rate Base	**2,757,379,941**		
	Pre-tax Return	8.88%		
	Rate Base Revenue Requirement	**244,905,370**		
	Annual Embedded Cost			
	All Other Generation Resources	**1,538,695,552**	30,407,910	50.60
	Total Annual Embedded Costs	**1,661,103,658**	**33,762,676**	**49.20**

Tab 10 - 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	1.4673%	26.0703%	7.8389%	44.3949%	6.0059%	14.1933%	0.0293%	0.0000%	0.0000%	Pg 10.16
Divisional Generation - Pac. Power	DGP	3.1128%	55.3072%	16.6300%	0.0000%	0.0000%	24.9499%	0.0000%	0.0000%	0.0000%	Pg 10.16
Divisional Generation - R.M.P.	DGU	0.0000%	0.0000%	0.0000%	83.9816%	11.3613%	4.6017%	0.0554%	0.0000%	0.0000%	Pg 10.16
System Capacity	SC	1.4853%	26.4044%	7.9926%	44.4439%	5.8665%	13.7796%	0.0277%	0.0000%	0.0000%	Pg 10.16
System Energy	SE	1.4133%	25.0681%	7.3781%	44.2480%	6.4241%	15.4344%	0.0340%	0.0000%	0.0000%	Pg 10.16
System Overhead	SO	2.2051%	27.1731%	7.6767%	43.9355%	5.8423%	13.1469%	0.0206%	0.0000%	0.0000%	Pg 10.7
Gross Plant-System	GPS	2.2051%	27.1731%	7.6767%	43.9355%	5.8423%	13.1469%	0.0206%	0.0000%	0.0000%	Pg 10.6
System Net Plant	SNP	2.0832%	25.5986%	7.4574%	45.7605%	5.9211%	13.1477%	0.0210%	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	2.0425%	48.4851%	14.7131%	28.6331%	5.3944%	0.7318%	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	1.4737%	26.1849%	7.7872%	44.1781%	6.0909%	14.2557%	0.0294%	0.0000%	0.0000%	Pg 10.3
System Net Transmission Plant	SNPT	1.4673%	26.0703%	7.8389%	44.3949%	6.0059%	14.1933%	0.0293%	0.0000%	0.0000%	Pg 10.4
System Net Production Plant	SNPP	1.5045%	24.2823%	8.0141%	45.4126%	6.1746%	14.5537%	0.0300%	0.0282%	0.0000%	Pg 10.4
System Net Hydro Plant	SNPPH	1.4628%	25.9912%	7.8152%	44.2602%	5.9877%	14.1503%	0.0292%	0.3034%	0.0000%	Pg 10.3
System Net Other Production Plant	SNPPO	1.5243%	23.1918%	8.1434%	46.1265%	6.2391%	14.7445%	0.0304%	0.0000%	0.0000%	Pg 10.4
System Net General Plant	SNPG	2.6778%	28.0469%	6.3177%	41.8563%	6.5308%	14.5586%	0.0120%	0.0000%	0.0000%	Pg 10.5
System Net Intangible Plant	SNPI	1.8850%	26.6419%	7.7896%	43.5059%	6.3827%	13.7735%	0.0214%	0.0000%	0.0000%	Pg 10.6
Trojan Plant Allocator	TROJP	1.4591%	25.9181%	7.7689%	44.3726%	6.0694%	14.3819%	0.0300%	0.0000%	0.0000%	Pg 10.12
Trojan Decommissioning Allocator	TROJD	1.4576%	25.8912%	7.7566%	44.3687%	6.0806%	14.4152%	0.0301%	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	1.7753%	22.6477%	6.6681%	37.9597%	5.0550%	11.6599%	0.0197%	14.2146%	0.0000%	Pg 10.12
System Generation Cholla Transaction	SGCT	1.4677%	26.0780%	7.8412%	44.4079%	6.0077%	14.1975%	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	101,912,184	1,810,735,721	544,460,031	3,083,484,225	417,144,788	985,807,771	2,032,437	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	101,912,184	1,810,735,721	544,460,031	3,083,484,225	417,144,788	985,807,771	2,032,437	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)	(10,993,303)	(195,324,698)	(58,731,095)	(332,616,526)	(44,997,555)	-106,339,430	(219,240)	0	0	
	DGU	(719,880,716)	(10,562,782)	(187,675,365)	(56,431,059)	(319,590,551)	(43,235,354)	-102,174,951	(210,654)	0	0	
	SG	(3,397,616,381)	(49,853,093)	(885,770,211)	(266,337,307)	(1,508,369,467)	(204,057,623)	-482,234,457	(994,222)	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)	(71,409,178)	(1,268,770,274)	(383,284,269)	(2,169,103,359)	(291,077,457)	(690,748,839)	(1,424,115)	0	0	
TOTAL NET STEAM PLANT		2,069,759,666	30,503,006	541,965,446	161,175,761	914,380,866	126,067,331	295,058,932	608,322	0	0	
SNPPS												
SYSTEM NET PLANT PRODUCTION STEAM		100.0000%	1.4737%	26.1849%	7.7872%	44.1781%	6.0909%	14.2557%	0.0294%	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	1,233,738,762	18,102,601	321,639,915	96,712,113	547,717,479	74,097,182	175,108,451	361,021	0	0	
		1,233,738,762	18,102,601	321,639,915	96,712,113	547,717,479	74,097,182	175,108,451	361,021	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)	(2,484,959)	(44,151,776)	(13,275,751)	(75,185,629)	(10,171,381)	(24,037,281)	(49,558)	0	0	
	DGU	(31,496,322)	(462,144)	(8,211,199)	(2,468,980)	(13,982,771)	(1,891,639)	(4,470,373)	(9,217)	0	0	
	SG	(341,316,594)	(5,008,125)	(88,982,403)	(26,755,623)	(151,527,268)	(20,499,151)	(48,444,146)	(99,877)	0	0	
		(540,064,787)	(7,955,228)	(141,345,378)	(42,500,354)	(240,695,668)	(32,562,172)	(76,951,800)	(158,651)	2,104,465	0	
TOTAL NET HYDRO PRODUCTION PLANT		693,673,975	10,147,373	180,294,537	54,211,759	307,021,811	41,535,010	98,156,652	202,369	2,104,465	0	
SNPPH												
SYSTEM NET PLANT PRODUCTION HYDRO		100.0000%	1.4628%	25.9912%	7.8152%	44.2602%	5.9877%	14.1503%	0.0292%	0.3034%	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	77,654,031	1,379,726,371	414,862,232	2,349,522,601	317,851,831	751,155,988	1,548,656	0	0	
	SSGCT	0	0	0	0	0	0	0	0	0	0	
		5,293,070,474	77,654,031	1,380,116,672	414,862,232	2,349,881,063	317,851,831	751,155,988	1,548,656	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	2,967,230	52,720,573	15,852,255	89,777,350	12,145,401	28,702,339	59,176	0	0	
	DGU	0	0	0	0	0	0	0	0	0	0	
	SG	(570,089,603)	(8,364,903)	(148,624,309)	(44,689,015)	(253,090,889)	(34,239,042)	(80,914,623)	(166,821)	0	0	
	SSGCT	(43,837,829)	(643,231)	(11,428,672)	(3,436,424)	(19,461,774)	(2,632,859)	(6,222,042)	(12,828)	0	0	
		(594,903,358)	(6,040,904)	(290,527,875)	(32,273,184)	(182,780,096)	(24,726,499)	(58,434,326)	(120,474)	0	0	
TOTAL NET OTHER PRODUCTION PLANT		4,698,167,116	71,613,127	1,089,588,797	382,589,048	2,167,100,967	293,125,332	692,721,661	1,428,183	0	0	
SNPPO												
SYSTEM NET PLANT PRODUCTION OTHER		100.0000%	1.5243%	23.1918%	8.1434%	46.1265%	6.2391%	14.7445%	0.0304%	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	13,471,637,631	197,668,816	3,512,102,007	1,056,034,376	5,980,724,306	809,093,802	1,912,072,210	3,942,115	0	0	
	SSGCH	0	0	0	0	0	0	0	0	0	0	
	SSGCT	0	0	0	0	0	0	0	0	0	0	
		13,472,386,393	197,668,816	3,512,492,308	1,056,034,376	5,981,082,767	809,093,802	1,912,072,210	3,942,115	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	(5,820,591,304)	(85,405,310)	(1,517,448,061)	(456,272,999)	(2,584,047,526)	(349,579,203)	(826,134,965)	(1,703,240)	0	0	
	SSGCH	0	0	0	0	0	0	0	0	0	0	
	SSGCT	0	0	0	0	0	0	0	0	0	0	
		(6,010,785,637)	(85,405,310)	(1,700,643,528)	(458,057,807)	(2,592,579,123)	(348,366,128)	(826,134,965)	(1,703,240)	2,104,465	0	
TOTAL NET PRODUCTION PLANT		7,461,600,757	112,263,506	1,811,848,780	597,976,569	3,388,503,644	460,727,674	1,085,937,245	2,238,874	2,104,465	0	
SNPP												
SYSTEM NET PRODUCTION PLANT		100.0000%	1.5045%	24.2823%	8.0141%	45.4126%	6.1746%	14.5537%	0.0300%	0.0282%	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	8,043,847,692	118,027,065	2,097,058,605	630,552,863	3,571,060,677	483,105,877	1,141,688,787	2,353,817	0	0	
		8,043,847,692	118,027,065	2,097,058,605	630,552,863	3,571,060,677	483,105,877	1,141,688,787	2,353,817	0	0	
LESS ACCUMULATED DEPRECIATION												
	DGP	(353,157,214)	(5,181,862)	(92,069,293)	(27,683,803)	(156,783,903)	(21,210,288)	(50,124,722)	(103,342)	0	0	
	DGU	(426,788,101)	(6,262,245)	(111,265,118)	(33,455,688)	(189,472,285)	(25,632,489)	(60,575,387)	(124,888)	0	0	
	SG	(1,394,500,313)	(20,461,449)	(363,551,001)	(109,314,124)	(619,087,460)	(83,752,369)	(197,925,848)	(408,063)	0	0	
		(2,174,445,627)	(31,905,556)	(566,885,412)	(170,453,615)	(965,343,648)	(130,595,146)	(308,625,957)	(636,293)	0	0	
TOTAL NET TRANSMISSION PLANT		5,869,402,064	86,121,509	1,530,173,193	460,099,248	2,605,717,029	352,510,731	833,062,830	1,717,524	0	0	
SNPT												
SYSTEM NET PLANT TRANSMISSION		100.0000%	1.4673%	26.0703%	7.8389%	44.3949%	6.0059%	14.1933%	0.0293%	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	765,688,819	23,960,387	245,798,256	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	43,112	764,714	225,072	1,349,803	195,969	470,834	1,037		
	SG	324,821,855	4,766,098	84,682,168	25,462,609	144,204,440	19,508,493	46,102,995	95,050		
	SO	406,724,719	8,968,614	110,519,641	31,222,891	178,696,358	23,761,896	53,471,621	83,699		
	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)	(144,981)	(4,188,634)	(774,554)	(6,942,398)	(593,434)	(1,402,420)	(2,891)		
		1,501,742,497	37,956,695	442,381,405	106,860,240	605,093,318	98,415,872	210,858,071	176,896		
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)	(10,495)	(186,466)	(56,067)	(317,531)	(42,957)	(101,517)	(209)		
	DGU	(1,951,711)	(28,637)	(508,818)	(152,994)	(866,461)	(117,218)	(277,012)	(571)		
	SE	(1,494,391)	(21,120)	(374,616)	(110,258)	(661,238)	(96,001)	(230,651)	(508)		
	SG	(138,970,814)	(2,039,113)	(36,230,166)	(10,893,847)	(61,695,998)	(8,346,455)	(19,724,568)	(40,666)		
	SO	(127,417,065)	(2,809,651)	(34,623,143)	(9,781,380)	(55,981,268)	(7,444,030)	(16,751,372)	(26,221)		
	CN	(6,909,506)	(161,962)	(2,141,251)	(472,901)	(3,337,151)	(293,145)	(503,097)	0		
	SSGCT	(130,406)	(1,913)	(33,997)	(10,222)	(57,894)	(7,832)	(18,509)	(38)		
	SSGCH	0	0	0	0	0	0	0	0		
		(594,338,157)	(13,658,112)	(187,882,849)	(49,533,513)	(225,287,626)	(39,155,132)	(78,752,711)	(68,214)		
TOTAL NET GENERAL PLANT		907,404,339	24,298,582	254,498,557	57,326,727	379,805,692	59,260,740	132,105,360	108,682		
SNPG											
SYSTEM NET GENERAL PLANT		100.0000%	2.6778%	28.0469%	6.3177%	41.8563%	6.5308%	14.5586%	0.0120%		
MINING :		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**		

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.
GENERAL MINING PLANT											
	SE	50,741,701	717,118	12,719,998	3,743,773	22,452,176	3,259,688	7,831,691	17,257		
LESS ACCUMULATED DEPRECIATION											
	SE	0	0	0	0	0	0	0	0		
		50,741,701	717,118	12,719,998	3,743,773	22,452,176	3,259,688	7,831,691	17,257		
SNPM											
SYSTEM NET PLANT MINING		100.0000%	1.4133%	25.0681%	7.3781%	44.2480%	6.4241%	15.4344%	0.0340%		
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)	(909)	(16,125)	(4,746)	(28,462)	(4,132)	(9,928)	(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	5,828,941	103,566,342	31,140,786	176,362,115	23,858,898	56,383,990	116,247		
	SO	476,788,634	10,513,580	129,558,166	36,601,462	209,479,258	27,855,208	62,682,842	98,118		
	SSGCT	0	0	0	0	0	0	0	0		
	SSGCH	0	0	0	0	0	0	0	0		
		1,078,469,287	21,830,438	303,922,649	84,396,010	462,820,731	65,143,232	140,141,885	214,342		
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)	(5,826)	(103,514)	(31,125)	(176,274)	(23,847)	(56,356)	(116)		
	SE	84,709	1,197	21,235	6,250	37,482	5,442	13,074	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)	(3,521,949)	(62,576,611)	(18,815,812)	(106,561,101)	(14,415,967)	(34,068,202)	(70,238)		
	SO	(339,134,793)	(7,478,200)	(92,153,375)	(26,034,239)	(149,000,416)	(19,813,120)	(44,585,653)	(69,790)		
	SSGCT	0	0	0	0	0	0	0	0		
	SSGCH	0	0	0	0	0	0	0	0		
		(731,862,209)	(15,296,879)	(211,580,064)	(57,396,715)	(312,026,116)	(43,020,514)	(92,401,806)	(140,116)		
TOTAL NET INTANGIBLE PLANT		346,607,078	6,533,558	92,342,586	26,999,296	150,794,614	22,122,718	47,740,079	74,227		
SNPI											
SYSTEM NET INTANGIBLE PLANT		100.0000%	1.8850%	26.6419%	7.7896%	43.5059%	6.3827%	13.7735%	0.0214%		
GROSS PLANT :		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**Other**	**Non-Utility**
PRODUCTION PLANT		13,472,386,393	197,668,816	3,512,492,308	1,056,034,376	5,981,082,767	809,093,802	1,912,072,210	3,942,115	0	0
TRANSMISSION PLANT		8,043,847,692	118,027,065	2,097,058,605	630,552,863	3,571,060,677	483,105,877	1,141,688,787	2,353,817	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		1,552,484,198	38,673,812	455,101,404	110,604,013	627,545,494	101,675,560	218,689,762	194,152	0	0
INTANGIBLE PLANT		1,078,469,287	21,830,438	303,922,649	84,396,010	462,820,731	65,143,232	140,141,885	214,342	0	0
TOTAL GROSS PLANT		32,579,238,234	718,398,912	8,852,783,093	2,500,998,697	14,313,836,688	1,903,362,212	4,283,154,205	6,704,427	0	0
GPS											
GROSS PLANT-SYSTEM FACTOR		100.0000%	2.2051%	27.1731%	7.6767%	43.9355%	5.8423%	13.1469%	0.0206%	0.0000%	0.0000%
ACCUMULATED DEPRECIATION AND AMORTIZATION											
PRODUCTION PLANT		(6,010,785,637)	(85,405,310)	(1,700,643,528)	(458,057,807)	(2,592,579,123)	(348,366,128)	(826,134,965)	(1,703,240)	2,104,465	0
TRANSMISSION PLANT		(2,174,445,627)	(31,905,556)	(566,885,412)	(170,453,615)	(965,343,648)	(130,595,146)	(308,625,957)	(636,293)	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)	(13,658,112)	(187,882,849)	(49,533,513)	(225,287,626)	(39,155,132)	(78,752,711)	(68,214)	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.
INTANGIBLE PLANT		(731,862,209)	(15,296,879)	(211,580,064)	(57,396,715)	(312,026,116)	(43,020,514)	(92,401,806)	(140,116)	0	0	
		(12,799,571,202)	(306,357,428)	(3,789,473,120)	(1,025,944,066)	(5,262,568,021)	(732,196,177)	(1,682,588,991)	(2,547,863)	2,104,465	0	
NET PLANT		19,779,667,032	412,041,484	5,063,309,973	1,475,054,632	9,051,268,667	1,171,166,034	2,600,565,215	4,156,563	2,104,465	0	
SNP												
SYSTEM NET PLANT FACTOR (SNP)		100.0000%	2.0832%	25.5986%	7.4574%	45.7605%	5.9211%	13.1477%	0.0210%	0.0106%	0.0000%	
NON-UTILITY RELATED INTEREST PERCENTAGE		0.0000%										
INT												
INTEREST FACTOR SNP - NON-UTILITY		100.0000%	2.0832%	25.5986%	7.4574%	45.7605%	5.9211%	13.1477%	0.0210%	0.0106%	0.0000%	
TOTAL GROSS PLANT (LESS SO FACTOR)		31,695,724,881	698,916,719	8,612,705,286	2,433,174,345	13,925,661,073	1,851,745,108	4,166,999,742	6,522,610	0	0	
SO												
SYSTEM OVERHEAD FACTOR (SO)		100.0000%	2.2051%	27.1731%	7.6767%	43.9355%	5.8423%	13.1469%	0.0206%	0.0000%	0	

IBT											
INCOME BEFORE TAXES		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**Other**	**Non-Utility**
INCOME BEFORE STATE TAXES		211,149,047	12,992,336	(35,577,313)	33,446,441	279,930,728	33,044,431	(24,722,110)	11,311,555	(56,303,100)	(42,973,921)
Interest Synchronization		(14,670,379)	(305,607)	(3,755,406)	(1,094,033)	(6,713,234)	(868,642)	(1,928,813)	(3,083)	(1,561)	-
		196,478,668	12,686,729	(39,332,719)	32,352,408	273,217,494	32,175,789	(26,650,923)	11,308,472	(56,304,661)	(42,973,921)
INCOME BEFORE TAXES (FACTOR)		100.0000%	6.4571%	-20.0188%	16.4661%	139.0571%	16.3762%	-13.5643%	5.7556%	-28.6569%	-21.8721%
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

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.
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

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.
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		12,972,501	264,963	6,289,730	1,908,655	3,714,434	699,789	0	0	0	0	
Bad Debts Expense Allocation Factor - BADDEBT			2.0425%	48.4851%	14.7131%	28.6331%	5.3944%	0.7318%	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%	

		Total Company	Idaho - PPL	Idaho - UPL	Idaho Total
IDSIT					
	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			180,214,838	12,402,484	(39,807,739)	31,927,972	267,221,873	31,544,214	(23,599,726)	10,798,010	(69,249,346)	(41,022,905)	
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			180,214,838	12,402,484	(39,807,739)	31,927,972	267,221,873	31,544,214	(23,599,726)	10,798,010	(69,249,346)	(41,022,905)	
Excise Tax (Superfund) Factor - EXCTAX			100.0000%	6.8821%	-22.0890%	17.7166%	148.2796%	17.5037%	-13.0953%	5.9917%	-38.4260%	-22.7633%	
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	249,537	4,433,676	1,333,137	7,550,064	1,021,400	2,413,799	4,977	0	0	
Dec 1991 Reserve			(7,851,432)										
Dec 1992 Reserve			(8,434,030)										
Average	SG		(8,142,731)	(119,478)	(2,122,838)	(638,304)	(3,614,960)	(489,045)	(1,155,724)	(2,383)	0	0	
Postmerger													
Dec 1991 Plant			4,284,960										
Dec 1992 Plant			3,485,613										
Average	SG		3,885,287	57,009	1,012,908	304,566	1,724,871	233,347	551,451	1,137	0	0	
Dec 1991 Reserve			(129,394)										
Dec 1992 Reserve			(240,609)										
Average	SG		(185,002)	(2,715)	(48,231)	(14,502)	(82,132)	(11,111)	(26,258)	(54)	0	0	
Net Plant			12,564,143	184,353	3,275,515	984,896	5,577,843	754,591	1,783,269	3,677	0	0	
Division Net Plant Nuclear Pacific Power	**DNPPNP**		100.0000%	1.4673%	26.0703%	7.8389%	44.3949%	6.0059%	14.1933%	0.0293%	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%	1.4673%	26.0703%	7.8389%	44.3949%	6.0059%	14.1933%	0.0293%	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	250,823	4,456,517	1,340,005	7,588,959	1,026,662	2,426,234	5,002	0	0	
	(108)	SG	(8,434,030)	(123,752)	(2,198,780)	(661,139)	(3,744,282)	(506,540)	(1,197,069)	(2,468)	0	0	
Post-merger	(101)	SG	3,485,613	51,144	908,711	273,235	1,547,436	209,343	494,724	1,020	0	0	
	(108)	SG	(240,609)	(3,530)	(62,728)	(18,861)	(106,818)	(14,451)	(34,150)	(70)	0	0	
	(107)	SG	1,778,549	26,097	463,674	139,419	789,586	106,818	252,435	520	0	0	
	(120)	SE	1,975,759	27,923	495,286	145,773	874,233	126,924	304,947	672	0	0	
	(228)	SG	7,220,849	105,951	1,882,500	566,038	3,205,691	433,677	1,024,878	2,113	0	0	
	(228)	SG	1,472,376	21,604	383,853	115,419	653,660	88,430	208,979	431	0	0	
	(228)	SNNP	3,531,000	51,810	920,544	276,793	1,567,585	212,069	501,166	1,033	0	0	
	(228)	SE	1,743,025	24,634	436,944	128,602	771,253	111,973	269,026	593	0	0	
Total Acct 182.22			29,626,734	432,703	7,686,521	2,305,286	13,147,303	1,794,905	4,251,170	8,846	0	0	
Revised Study	(228)	SNNP	112,680	1,653	29,376	8,833	50,024	6,767	15,993	33	0	0	
	(228)	SE	941,950	13,312	236,129	69,498	416,794	60,512	145,385	320	0	0	
December 1993 Adj.			1,054,630	14,966	265,505	78,331	466,818	67,279	161,378	353	0	0	
Adjusted Acct 182.22			30,681,364	447,668	7,952,026	2,383,617	13,614,121	1,862,184	4,412,548	9,199	0	0	
TROJP			100.0000%	1.4591%	25.9181%	7.7689%	44.3726%	6.0694%	14.3819%	0.0300%	0.0000%	0.0000%	
Trojan Plant Allocator													
Account 228.42			TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC	Other	Non-Utility	
Plant - Premerger		SG	7,220,849	105,951	1,882,500	566,038	3,205,691	433,677	1,024,878	2,113	0	0	
- Postmerger		SG	1,472,376	21,604	383,853	115,419	653,660	88,430	208,979	431	0	0	
Storage Facility		SE	1,743,025	24,634	436,944	128,602	771,253	111,973	269,026	593	0	0	
Transition Costs		SNNP	3,531,000	51,810	920,544	276,793	1,567,585	212,069	501,166	1,033	0	0	
Total Acct 228.42			13,967,250	203,999	3,623,841	1,086,853	6,198,190	846,149	2,004,049	4,170	0	0	
Transition Costs		SNNP	112,680	1,653	29,376	8,833	50,024	6,767	15,993	33	0	0	
Storage Facility		SE	941,950	13,312	236,129	69,498	416,794	60,512	145,385	320	0	0	
December 1993 Adj.			1,054,630	14,966	265,505	78,331	466,818	67,279	161,378	353	0	0	
Adjusted Acct 228.42			15,021,880	218,965	3,889,346	1,165,183	6,665,008	913,428	2,165,427	4,523	0	0	
TROJD			100.0000%	1.4576%	25.8912%	7.7566%	44.3687%	6.0806%	14.4152%	0.0301%	0.0000%	0.0000%	
Trojan Decommissioning Allocator													
SCHMA			TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC	Other	Non-Utility	
Amortization Expense :													
Amortization of Limited Term Plant		Acct 404	58,576,334	1,127,735	15,333,788	4,122,769	24,274,949	2,955,813	6,519,428	9,115	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	26,265	466,658	140,317	1,096,303	107,505	254,060	524	0	0	
Amort of Prop. Losses, Unrecovered Plant, etc.		Acct 407	29,604,150	14,110	27,436,855	75,384	1,758,983	57,756	136,491	281	124,290	0	
Total Amortization Expense :			90,272,115	1,168,110	43,237,301	4,338,470	27,130,234	3,121,074	6,909,979	9,920	4,357,028	0	
Schedule M Amortization Factor			100.0000%	1.2940%	47.8966%	4.8060%	30.0538%	3.4574%	7.6546%	0.0110%	4.8265%	0.0000%	
SCHMD			TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC	Other	Non-Utility	
Depreciation Expense :													
Steam		Acct 403.1	626,491,403	6,540,257	116,204,721	34,940,950	197,883,888	26,770,441	63,264,626	130,433	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	34,898,599	512,066	9,098,184	2,735,682	15,493,209	2,095,977	4,953,269	10,212	0	0	
Other	Acct 403.4	209,943,056	3,080,416	54,731,626	16,456,947	93,206,736	12,608,694	29,797,204	61,433	0	0	
Transmission	Acct 403.5	138,230,148	2,028,246	36,037,072	10,835,786	61,367,180	8,301,972	19,619,443	40,449	0	0	
Distribution	Acct 403.6	209,732,961	9,254,102	56,428,045	16,032,588	93,266,338	11,380,194	23,371,694	0	0	0	
General	Acct 403.7&8	52,330,149	1,160,256	15,494,647	3,791,197	21,488,305	3,123,110	7,264,733	7,902	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 :		1,271,626,317	22,575,342	287,994,295	84,793,152	482,705,656	64,280,387	148,270,968	250,428	180,756,088	0	
Schedule M Depreciation Factor		100.0000%	1.7753%	22.6477%	6.6681%	37.9597%	5.0550%	11.6599%	0.0197%	14.2146%	0.0000%	

	TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC	Other	Non-Utility
Tax Depreciation by Function										
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 (Non-FERC)	OR	WA	UT	ID	WY	FERC	Total
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

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Adjustments for Curtailments, Buy-Throughs and Load No Longer Served (Reductions to Load)

Month	Day	Time	CA (Non-FERC)	OR	WA	UT	ID	WY	FERC	Total
Jan-23	12	8	-	-	-	198	-	-	30	228
Feb-23	7	8	-	-	-	201	-	-	32	233
Mar-23	9	8	-	-	-	202	-	-	32	233
Apr-23	5	8	-	-	-	202	-	-	32	234
May-23	16	16	-	-	-	233	-	-	21	254
Jun-23	22	16	-	-	-	359	170	-	31	560
Jul-23	17	16	-	-	-	385	146	-	32	563
Aug-23	24	16	-	-	-	305	79	-	33	417
Sep-23	7	16	-	-	-	352	-	-	34	386
Oct-23	2	18	-	-	-	220	-	-	33	252
Nov-23	22	18	-	-	-	222	-	-	32	255
Dec-23	13	18	-	-	-	304	-	-	33	337
			-	-	-	3,182	395	-	376	3,953

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COINCIDENTAL PEAK SERVED FROM COMPANY RESOURCES

Month	Day	Time	CA (Non-FERC)	OR	WA	UT	ID	WY	FERC	Total
Jan-23	12	8	148	2,655	838	3,297	469	1,223	3	8,633
Feb-23	7	8	139	2,484	704	3,237	453	1,184	3	8,204
Mar-23	9	8	135	2,379	674	3,093	437	1,167	2	7,886
Apr-23	5	8	117	2,196	576	2,886	426	1,105	2	7,308
May-23	16	16	113	1,917	577	3,842	545	1,095	1	8,090
Jun-23	22	16	129	2,051	684	4,554	599	1,200	2	9,219
Jul-23	17	16	140	2,409	760	4,791	637	1,237	3	9,978
Aug-23	24	16	132	2,474	743	4,728	537	1,202	3	9,818
Sep-23	7	16	116	2,161	660	4,321	556	1,146	2	8,962
Oct-23	2	18	103	1,901	602	3,563	429	1,129	2	7,730
Nov-23	22	18	122	2,196	695	3,508	466	1,236	2	8,225
Dec-23	13	18	136	2,398	726	3,619	494	1,282	3	8,658
			1,531	27,220	8,239	45,441	6,048	14,205	29	102,712

+ plus

Adjustments for Ancillary Services Contracts including Reserves and Direct Access (Additions to Load)

Month	Day	Time	CA (Non-FERC)	OR	WA	UT	ID	WY	FERC	Total
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 (Non-FERC)	OR	WA	UT	ID	WY	FERC	Total
Jan-23	12	8	148	2,655	838	3,327	469	1,223	3	8,663
Feb-23	7	8	139	2,484	704	3,269	453	1,184	3	8,235
Mar-23	9	8	135	2,379	674	3,125	437	1,167	2	7,918
Apr-23	5	8	117	2,196	576	2,919	426	1,105	2	7,341
May-23	16	16	113	1,917	577	3,863	545	1,095	1	8,112
Jun-23	22	16	129	2,051	684	4,585	599	1,200	2	9,251
Jul-23	17	16	140	2,409	760	4,823	637	1,237	3	10,010
Aug-23	24	16	132	2,474	743	4,761	537	1,202	3	9,852
Sep-23	7	16	116	2,161	660	4,355	556	1,146	2	8,996
Oct-23	2	18	103	1,901	602	3,596	429	1,129	2	7,763
Nov-23	22	18	122	2,196	695	3,540	466	1,236	2	8,257
Dec-23	13	18	136	2,398	726	3,652	494	1,282	3	8,691
			1,531	27,220	8,239	45,816	6,048	14,205	29	103,088

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				55,864		-	22,398	78,262
2023	Feb				48,407		-	21,260	69,667
2023	Mar				76,018		-	22,559	98,577
2023	Apr				83,808		-	22,741	106,548
2023	May				81,921		-	22,610	104,531
2023	Jun				80,771		-	21,664	102,435
2023	Jul				85,708		-	23,098	108,807
2023	Aug				92,440		-	23,408	115,848
2023	Sep				94,556		-	23,468	118,024
2023	Oct				96,135		-	23,815	119,950
2023	Nov				96,195		-	23,240	119,434
2023	Dec				70,963		-	24,079	95,041
		-	-	-	962,785	-	-	274,339	1,237,124

= 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	2,242,326	309,560	813,290	2,042	5,322,009
2023	Feb	67,180	1,257,950	370,680	1,988,533	270,310	736,210	1,750	4,692,613
2023	Mar	68,700	1,298,140	362,940	2,057,822	281,240	802,650	1,691	4,873,183
2023	Apr	66,270	1,190,510	327,090	1,968,922	277,990	762,420	1,448	4,594,650
2023	May	71,900	1,181,490	334,590	2,082,049	335,990	765,160	1,462	4,772,642
2023	Jun	75,680	1,179,260	343,070	2,325,589	416,930	783,120	1,490	5,125,139
2023	Jul	82,380	1,329,280	397,920	2,717,472	489,470	785,910	1,996	5,804,428
2023	Aug	78,240	1,311,840	392,590	2,647,640	393,900	820,570	1,991	5,646,771
2023	Sep	67,140	1,173,020	350,790	2,231,884	310,150	759,100	1,577	4,893,661
2023	Oct	62,970	1,187,200	361,320	2,088,935	277,630	780,910	1,570	4,760,535
2023	Nov	66,800	1,289,570	385,440	2,096,105	258,140	779,820	1,690	4,877,566
2023	Dec	77,510	1,474,010	441,550	2,302,987	302,220	837,470	2,062	5,437,810
		863,160	15,310,450	4,506,200	26,750,265	3,923,530	9,426,630	20,771	60,801,006

+ 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	2,264,725	309,560	813,290	2,042	5,344,407
2023	Feb	67,180	1,257,950	370,680	2,009,792	270,310	736,210	1,750	4,713,872
2023	Mar	68,700	1,298,140	362,940	2,080,381	281,240	802,650	1,691	4,895,742
2023	Apr	66,270	1,190,510	327,090	1,991,663	277,990	762,420	1,448	4,617,391
2023	May	71,900	1,181,490	334,590	2,104,660	335,990	765,160	1,462	4,795,252
2023	Jun	75,680	1,179,260	343,070	2,347,253	416,930	783,120	1,490	5,146,803
2023	Jul	82,380	1,329,280	397,920	2,740,570	489,470	785,910	1,996	5,827,526
2023	Aug	78,240	1,311,840	392,590	2,671,048	393,900	820,570	1,991	5,670,179
2023	Sep	67,140	1,173,020	350,790	2,255,352	310,150	759,100	1,577	4,917,129
2023	Oct	62,970	1,187,200	361,320	2,112,749	277,630	780,910	1,570	4,784,349
2023	Nov	66,800	1,289,570	385,440	2,119,345	258,140	779,820	1,690	4,900,805
2023	Dec	77,510	1,474,010	441,550	2,327,066	302,220	837,470	2,062	5,461,888
		863,160	15,310,450	4,506,200	27,024,604	3,923,530	9,426,630	20,771	61,075,345

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	27,024,604	3,923,530	9,426,630	20,771	**61,075,345**	**Ref Page 10.15**
System Energy Factor	1.4133%	25.0681%	7.3781%	44.2480%	6.4241%	15.4344%	0.0340%	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%	82.8793%	12.0327%	5.0243%	0.0637%	100.00%	
System Generation Factor	1.4673%	26.0703%	7.8389%	44.3949%	6.0059%	14.1933%	0.0293%	100.00%	
Divisional Generation - Pacific	3.1128%	55.3072%	16.6300%	0.0000%	0.0000%	24.9499%	0.0000%	100.00%	
Divisional Generation - Utah	0.0000%	0.0000%	0.0000%	83.9816%	11.3613%	4.6017%	0.0554%	100.00%	
System Capacity (kw)									
Accord	1,531.2	27,219.8	8,239.4	45,816.4	6,047.7	14,205.1	28.5	**103,088**	**Ref Page 10.14**
Modified Accord	1,531.2	27,219.8	8,239.4	45,816.4	6,047.7	14,205.1	28.5	**103,088**	**Ref Page 10.14**
Rolled-In	1,531.2	27,219.8	8,239.4	45,816.4	6,047.7	14,205.1	28.5	**103,088**	**Ref Page 10.14**
Rolled-In with Hydro Adj.	1,531.2	27,219.8	8,239.4	45,816.4	6,047.7	14,205.1	28.5	**103,088**	**Ref Page 10.14**
Rolled-In with Off-Sys Adj.	1,531.2	27,219.8	8,239.4	45,816.4	6,047.7	14,205.1	28.5	**103,088**	**Ref Page 10.14**
System Capacity Factor									
Accord	1.4853%	26.4044%	7.9926%	44.4439%	5.8665%	13.7796%	0.0277%	100.00%	
Modified Accord	1.4853%	26.4044%	7.9926%	44.4439%	5.8665%	13.7796%	0.0277%	100.00%	
Rolled-In	1.4853%	26.4044%	7.9926%	44.4439%	5.8665%	13.7796%	0.0277%	100.00%	
Rolled-In with Hydro Adj.	1.4853%	26.4044%	7.9926%	44.4439%	5.8665%	13.7796%	0.0277%	100.00%	
Rolled-In with Off-Sys Adj.	1.4853%	26.4044%	7.9926%	44.4439%	5.8665%	13.7796%	0.0277%	100.00%	
System Energy (kwh)									
Accord	863,160	15,310,450	4,506,200	27,024,604	3,923,530	9,426,630	20,771	61,075,345	
Modified Accord	863,160	15,310,450	4,506,200	27,024,604	3,923,530	9,426,630	20,771	61,075,345	
Rolled-In	863,160	15,310,450	4,506,200	27,024,604	3,923,530	9,426,630	20,771	61,075,345	
Rolled-In with Hydro Adj.	863,160	15,310,450	4,506,200	27,024,604	3,923,530	9,426,630	20,771	61,075,345	
Rolled-In with Off-Sys Adj.	863,160	15,310,450	4,506,200	27,024,604	3,923,530	9,426,630	20,771	61,075,345	
System Energy Factor									
Accord	1.4133%	25.0681%	7.3781%	44.2480%	6.4241%	15.4344%	0.0340%	100.00%	
Modified Accord	1.4133%	25.0681%	7.3781%	44.2480%	6.4241%	15.4344%	0.0340%	100.00%	
Rolled-In	1.4133%	25.0681%	7.3781%	44.2480%	6.4241%	15.4344%	0.0340%	100.00%	
Rolled-In with Hydro Adj.	1.4133%	25.0681%	7.3781%	44.2480%	6.4241%	15.4344%	0.0340%	100.00%	
Rolled-In with Off-Sys Adj.	1.4133%	25.0681%	7.3781%	44.2480%	6.4241%	15.4344%	0.0340%	100.00%	
System Generation Factor									
Accord	1.4673%	26.0703%	7.8389%	44.3949%	6.0059%	14.1933%	0.0293%	100.00%	
Modified Accord	1.4673%	26.0703%	7.8389%	44.3949%	6.0059%	14.1933%	0.0293%	100.00%	
Rolled-In	1.4673%	26.0703%	7.8389%	44.3949%	6.0059%	14.1933%	0.0293%	100.00%	
Rolled-In with Hydro Adj.	1.4673%	26.0703%	7.8389%	44.3949%	6.0059%	14.1933%	0.0293%	100.00%	
Rolled-In with Off-Sys Adj.	1.4673%	26.0703%	7.8389%	44.3949%	6.0059%	14.1933%	0.0293%	100.00%	

B1. REVENUE

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
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	-	-

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	OR	17,786	-	17,786	-	-	-	-	-	-
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	-	-

PACIFICORP

Electric Operations Revenue (Actuals)
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Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
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	-	-	-
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	1,923	578	1,047	3,275	443	2	-
4471300 Total					**7,377**	**108**	**1,923**	**578**	**1,047**	**3,275**	**443**	**2**	**-**
4471400	S/T FIRM WHOLESALE	301406	SHORT-TERM FIRM WHOLESALE SALES	SG	277,598	4,073	72,371	21,761	39,400	123,239	16,672	81	-

PACIFICORP

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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)	(356)	(48)	(0)	-
4471400	S/T FIRM WHOLESALE	301411	BOOKOUT SALES NETTED	SG	(105,787)	(1,552)	(27,579)	(8,293)	(15,015)	(46,964)	(6,353)	(31)	-
4471400	S/T FIRM WHOLESALE	301412	BOOKOUT SALES NETTED-ESTIMATE	SG	1,731	25	451	136	246	768	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	14	240	72	131	409	55	0	-
4471400	S/T FIRM WHOLESALE	303028	LINE LOSS W/S TRADING REVENUES	SG	7,473	110	1,948	586	1,061	3,318	449	2	-
4471400 Total					**181,226**	**2,659**	**47,246**	**14,206**	**25,722**	**80,455**	**10,884**	**53**	**-**
4472000	SLS FOR RESL-SURP	301419	ESTIMATED SALES FOR RESALE REVENUE	SG	(341)	(5)	(89)	(27)	(48)	(151)	(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	772	13,724	4,127	7,472	23,370	3,162	15	-
4472000	SLS FOR RESL-SURP	303199	Non-ASC 606-WS NPC Rev-Derivativ (Recl)	SG	(52,642)	(772)	(13,724)	(4,127)	(7,472)	(23,370)	(3,162)	(15)	-
4472000 Total					**(324)**	**(5)**	**(85)**	**(25)**	**(46)**	**(144)**	**(19)**	**(0)**	**-**
4475000	OFF-SYS - NON FIRM	301408	OFF-SYSTEM WHOLESALE - NON FIRM	SE	(3,707)	(52)	(929)	(274)	(572)	(1,640)	(238)	(1)	-
4475000 Total					**(3,707)**	**(52)**	**(929)**	**(274)**	**(572)**	**(1,640)**	**(238)**	**(1)**	**-**
4476100	BOOKOUTS NETTED-GAIN	304101	BOOKOUTS NETTED-GAIN	SG	15,242	224	3,974	1,195	2,163	6,767	915	4	-
4476100 Total					**15,242**	**224**	**3,974**	**1,195**	**2,163**	**6,767**	**915**	**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)	(48)	(845)	(254)	(460)	(1,438)	(195)	(1)	-
4491800 Total					**(3,240)**	**(48)**	**(845)**	**(254)**	**(460)**	**(1,438)**	**(195)**	**(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)	-	-	-	-	-

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
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)**	**-**	**-**
4512000	TAMPER/RECONNECT	301826	TAMPERING/UNAUTHORIZED RECONNECTION CH	CA	0	0	-	-	-	-	-	-	-
4512000	TAMPER/RECONNECT	301826	TAMPERING/UNAUTHORIZED RECONNECTION CH	OR	4	-	4	-	-	-	-	-	-
4512000	TAMPER/RECONNECT	301826	TAMPERING/UNAUTHORIZED RECONNECTION CH	SO	0	0	0	0	0	0	0	0	-
4512000	TAMPER/RECONNECT	301826	TAMPERING/UNAUTHORIZED RECONNECTION CH	UT	1	-	-	-	-	1	-	-	-
4512000	TAMPER/RECONNECT	301826	TAMPERING/UNAUTHORIZED RECONNECTION CH	WA	0	-	-	0	-	-	-	-	-
4512000	TAMPER/RECONNECT	301826	TAMPERING/UNAUTHORIZED RECONNECTION CH	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	235	71	128	400	54	0	-
4541000	RENTS - COMMON	301860	RENT FROM ELEC PROP	SO	2,540	56	690	195	334	1,116	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	263	35	0	-

PACIFICORP

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Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4541000	RENTS - COMMON	301886	Rent Revenue - Subleases - Operating	SG	116	2	30	9	17	52	7	0	-
4541000 Total					**14,882**	**623**	**5,853**	**1,263**	**1,010**	**5,688**	**444**	**1**	**-**
4543000	MCI FOGWIRE REVENUES	301863	MCI FIBER OPTIC GROUND WIRE REVENUES	SG	3,355	49	875	263	476	1,489	201	1	-
4543000 Total					**3,355**	**49**	**875**	**263**	**476**	**1,489**	**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	563	169	306	958	130	1	-
4561100	Other Wheeling Rev	301963	Ancil Revenue Sch 2-Reactive (C&T)	SG	2,316	34	604	182	329	1,028	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	40	702	211	382	1,196	162	1	-
4561100	Other Wheeling Rev	301969	Ancillary Revenue Sch 3 - Reg&Freq (C&T)	SG	2,356	35	614	185	334	1,046	142	1	-
4561100	Other Wheeling Rev	301973	Ancillary Revenue Sch 5&6-Spin&Supp (C&T	SG	2,118	31	552	166	301	940	127	1	-
4561100	Other Wheeling Rev	301974	Ancil Revenue Sch 3a-Regulation (C&T)	SG	4,430	65	1,155	347	629	1,967	266	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	57	102	320	43	0	-
4561100	Other Wheeling Rev	302982	Transmission Rev-Unreserved Use Charges	SG	466	7	122	37	66	207	28	0	-
4561100	Other Wheeling Rev	302983	Transmission Revenue - Deferral Fees	SG	352	5	92	28	50	156	21	0	-
4561100 Total					**18,065**	**265**	**4,710**	**1,416**	**2,564**	**8,020**	**1,085**	**5**	**-**
4561910	S/T FIRM WHEEL REV	301926	SHORT TERM FIRM WHEELING	SG	3,177	47	828	249	451	1,410	191	1	-
4561910 Total					**3,177**	**47**	**828**	**249**	**451**	**1,410**	**191**	**1**	**-**
4561920	L/T FIRM WHEEL REV	301912	POST-MERGER FIRM WHEELING	SG	15,441	227	4,026	1,210	2,192	6,855	927	5	-
4561920	L/T FIRM WHEEL REV	301916	PRE-MERGER FIRM WHEELING	SG	7,434	109	1,938	583	1,055	3,300	446	2	-
4561920	L/T FIRM WHEEL REV	301917	PRE-MERGER FIRM WHEELING	SG	24,715	363	6,443	1,937	3,508	10,972	1,484	7	-
4561920	L/T FIRM WHEEL REV	302980	Transmisson Point-to-Point Revenue	SG	38,959	572	10,157	3,054	5,530	17,296	2,340	11	-
4561920 Total					**86,548**	**1,270**	**22,563**	**6,784**	**12,284**	**38,423**	**5,198**	**25**	**-**
4561930	NON-FIRM WHEEL REV	301922	NON-FIRM WHEELING REVENUE	SE	26,514	375	6,647	1,956	4,092	11,732	1,703	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**	**375**	**6,649**	**1,957**	**4,094**	**11,736**	**1,704**	**9**	**-**
4561990	TRANSMN REV REFUND	301913	Transmission Tariff True-up	SG	(4,553)	(67)	(1,187)	(357)	(646)	(2,021)	(273)	(1)	-
4561990 Total					**(4,553)**	**(67)**	**(1,187)**	**(357)**	**(646)**	**(2,021)**	**(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	385	116	210	655	89	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	179	3,177	955	1,730	5,411	732	4	-
4562300	MISC OTHER REV	301949	THIRD PARTY TRN O&M REV	SG	636	9	166	50	90	282	38	0	-
4562300	MISC OTHER REV	301951	NON-WHEELING SYS REV	SG	89	1	23	7	13	39	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)	(23)	(41)	(128)	(17)	(0)	-
4562300	MISC OTHER REV	301959	Wind-based Ancillary Services/Revenue	SG	10,822	159	2,821	848	1,536	4,804	650	3	-
4562300	MISC OTHER REV	361000	STEAM SALES	SG	168	2	44	13	24	74	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**	**370**	**6,575**	**1,947**	**3,693**	**11,212**	**1,515**	**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)	(778)	(220)	(376)	(1,258)	(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)**	**(777)**	**(219)**	**(301)**	**2,063**	**(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)	(714)	(215)	(389)	(1,216)	(165)	(1)	-
4562700	RNW ENRGY CRDT SALES	301944	Renewable Energy Credit Sales-Estimate	SG	150	2	39	12	21	66	9	0	-
4562700	RNW ENRGY CRDT SALES	301945	Renewable Energy Credit Sales	SG	8,884	130	2,316	696	1,261	3,944	534	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**	**1,641**	**493**	**893**	**2,795**	**378**	**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**

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
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					**5,521,910**	**108,348**	**1,434,724**	**380,470**	**654,514**	**2,483,484**	**329,923**	**12,608**	**117,840**

B2. O&M EXPENSE

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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
5000000	OPER SUPV & ENG	STEX	Steam O&M Expense	SG	14,521	213	3,786	1,138	2,061	6,447	872	4	-
5000000 Total					**14,521**	**213**	**3,786**	**1,138**	**2,061**	**6,447**	**872**	**4**	**-**
5001000	OPER SUPV & ENG	STEX	Steam O&M Expense	SG	429	6	112	34	61	190	26	0	-
5001000 Total					**429**	**6**	**112**	**34**	**61**	**190**	**26**	**0**	**-**
5010000	FUEL CONSUMED	NPCX	Net Power Cost Expense	SE	2,910	41	730	215	449	1,288	187	1	-
5010000 Total					**2,910**	**41**	**730**	**215**	**449**	**1,288**	**187**	**1**	**-**
5011000	FUEL CONSUMED-COAL	NPCX	Net Power Cost Expense	SE	648,726	9,168	162,623	47,864	100,127	287,048	41,675	221	-
5011000 Total					**648,726**	**9,168**	**162,623**	**47,864**	**100,127**	**287,048**	**41,675**	**221**	**-**
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	357	105	220	629	91	0	-
5011300 Total					**1,422**	**20**	**357**	**105**	**220**	**629**	**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	784	231	483	1,385	201	1	-
5011500 Total					**9,336**	**44**	**5,706**	**231**	**483**	**1,385**	**1,487**	**1**	**-**
5012000	FUEL HAND-COAL	STEX	Steam O&M Expense	SE	6,651	94	1,667	491	1,027	2,943	427	2	-
5012000 Total					**6,651**	**94**	**1,667**	**491**	**1,027**	**2,943**	**427**	**2**	**-**
5013000	START UP FUEL - GAS	NPCX	Net Power Cost Expense	SE	240	3	60	18	37	106	15	0	-
5013000 Total					**240**	**3**	**60**	**18**	**37**	**106**	**15**	**0**	**-**
5013500	FUEL CONSUMED-GAS	NPCX	Net Power Cost Expense	SE	18,261	258	4,578	1,347	2,818	8,080	1,173	6	-
5013500 Total					**18,261**	**258**	**4,578**	**1,347**	**2,818**	**8,080**	**1,173**	**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	57	1,008	297	621	1,779	258	1	-
5014500 Total					**4,021**	**57**	**1,008**	**297**	**621**	**1,779**	**258**	**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	610	10,840	3,259	5,901	18,459	2,497	12	-
5020000 Total					**41,579**	**610**	**10,840**	**3,259**	**5,901**	**18,459**	**2,497**	**12**	**-**
5022000	STM EXP - FLYASH	STEX	Steam O&M Expense	SG	7,447	109	1,942	584	1,057	3,306	447	2	-
5022000 Total					**7,447**	**109**	**1,942**	**584**	**1,057**	**3,306**	**447**	**2**	**-**
5023000	STM EXP BOTTOM ASH	STEX	Steam O&M Expense	SG	1,000	15	261	78	142	444	60	0	-
5023000 Total					**1,000**	**15**	**261**	**78**	**142**	**444**	**60**	**0**	**-**
5024000	STM EXP SCRUBBER	STEX	Steam O&M Expense	SG	11,796	173	3,075	925	1,674	5,237	708	3	-
5024000 Total					**11,796**	**173**	**3,075**	**925**	**1,674**	**5,237**	**708**	**3**	**-**
5029000	STM EXP - OTHER	STEX	Steam O&M Expense	SG	18,300	269	4,771	1,435	2,597	8,124	1,099	5	-
5029000 Total					**18,300**	**269**	**4,771**	**1,435**	**2,597**	**8,124**	**1,099**	**5**	**-**
5030000	STEAM FRM OTH SRCS	NPCX	Net Power Cost Expense	SE	5,120	72	1,283	378	790	2,265	329	2	-
5030000 Total					**5,120**	**72**	**1,283**	**378**	**790**	**2,265**	**329**	**2**	**-**
5050000	ELECTRIC EXPENSES	STEX	Steam O&M Expense	SG	1,120	16	292	88	159	497	67	0	-
5050000 Total					**1,120**	**16**	**292**	**88**	**159**	**497**	**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	1,145	20,348	6,118	11,078	34,651	4,688	23	-
5060000 Total					**78,051**	**1,145**	**20,348**	**6,118**	**11,078**	**34,651**	**4,688**	**23**	**-**
5061000	MISC STM EXP - CON	STEX	Steam O&M Expense	SG	1,717	25	448	135	244	762	103	1	-
5061000 Total					**1,717**	**25**	**448**	**135**	**244**	**762**	**103**	**1**	**-**
5061100	MISC STM EXP PLCLU	STEX	Steam O&M Expense	SG	1,826	27	476	143	259	811	110	1	-
5061100 Total					**1,826**	**27**	**476**	**143**	**259**	**811**	**110**	**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	42	75	236	32	0	-
5061300 Total					**531**	**8**	**138**	**42**	**75**	**236**	**32**	**0**	**-**
5061400	MISC STM EXP OFFIC	STEX	Steam O&M Expense	SG	1,450	21	378	114	206	644	87	0	-
5061400 Total					**1,450**	**21**	**378**	**114**	**206**	**644**	**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	52	916	275	498	1,559	211	1	-
5062000 Total					**3,512**	**52**	**916**	**275**	**498**	**1,559**	**211**	**1**	**-**
5063000	MISC STEAM JVA CR	STEX	Steam O&M Expense	SG	(36,143)	(530)	(9,423)	(2,833)	(5,130)	(16,046)	(2,171)	(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)**	**(530)**	**(9,423)**	**(2,833)**	**(5,130)**	**(16,046)**	**(2,171)**	**(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	187	25	0	-
5065000 Total					**422**	**6**	**110**	**33**	**60**	**187**	**25**	**0**	**-**
5066000	MISC STM EXP -SFTY	STEX	Steam O&M Expense	SG	836	12	218	66	119	371	50	0	-
5066000 Total					**836**	**12**	**218**	**66**	**119**	**371**	**50**	**0**	**-**
5067000	MISC STM EXP TRNNG	STEX	Steam O&M Expense	SG	3,461	51	902	271	491	1,536	208	1	-
5067000 Total					**3,461**	**51**	**902**	**271**	**491**	**1,536**	**208**	**1**	**-**
5069000	MISC STM EXP WTSPY	STEX	Steam O&M Expense	SG	473	7	123	37	67	210	28	0	-
5069000 Total					**473**	**7**	**123**	**37**	**67**	**210**	**28**	**0**	**-**
5069900	MISC STM EXP MISC	STEX	Steam O&M Expense	SG	2,473	36	645	194	351	1,098	149	1	-
5069900 Total					**2,473**	**36**	**645**	**194**	**351**	**1,098**	**149**	**1**	**-**
5070000	RENTS (STEAM GEN)	STEX	Steam O&M Expense	SG	467	7	122	37	66	207	28	0	-
5070000 Total					**467**	**7**	**122**	**37**	**66**	**207**	**28**	**0**	**-**
5100000	MNT SUPERV & ENG	STEX	Steam O&M Expense	SG	2,880	42	751	226	409	1,279	173	1	-
5100000 Total					**2,880**	**42**	**751**	**226**	**409**	**1,279**	**173**	**1**	**-**
5101000	MNTNCE SUPVSN &ENG	STEX	Steam O&M Expense	SG	4,174	61	1,088	327	592	1,853	251	1	-
5101000 Total					**4,174**	**61**	**1,088**	**327**	**592**	**1,853**	**251**	**1**	**-**
5110000	MNT OF STRUCTURES	STEX	Steam O&M Expense	SG	4,320	63	1,126	339	613	1,918	259	1	-
5110000 Total					**4,320**	**63**	**1,126**	**339**	**613**	**1,918**	**259**	**1**	**-**
5111000	MNT OF STRUCTURES	STEX	Steam O&M Expense	SG	4,005	59	1,044	314	568	1,778	241	1	-
5111000 Total					**4,005**	**59**	**1,044**	**314**	**568**	**1,778**	**241**	**1**	**-**
5111100	MNT STRCT PMP PLNT	STEX	Steam O&M Expense	SG	839	12	219	66	119	372	50	0	-
5111100 Total					**839**	**12**	**219**	**66**	**119**	**372**	**50**	**0**	**-**
5111200	MNT STRCT WASTE WT	STEX	Steam O&M Expense	SG	611	9	159	48	87	271	37	0	-
5111200 Total					**611**	**9**	**159**	**48**	**87**	**271**	**37**	**0**	**-**
5112000	STRUCTURAL SYSTEMS	STEX	Steam O&M Expense	SG	10,335	152	2,694	810	1,467	4,588	621	3	-
5112000 Total					**10,335**	**152**	**2,694**	**810**	**1,467**	**4,588**	**621**	**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	476	64	0	-
5117000 Total					**1,071**	**16**	**279**	**84**	**152**	**476**	**64**	**0**	**-**
5118000	MNT STRCT-GROUNDS	STEX	Steam O&M Expense	SG	627	9	163	49	89	278	38	0	-
5118000 Total					**627**	**9**	**163**	**49**	**89**	**278**	**38**	**0**	**-**
5119000	MNT OF STRCT-HVAC	STEX	Steam O&M Expense	SG	1,921	28	501	151	273	853	115	1	-
5119000 Total					**1,921**	**28**	**501**	**151**	**273**	**853**	**115**	**1**	**-**
5119900	MNT OF STRCT-MISC	STEX	Steam O&M Expense	SG	740	11	193	58	105	328	44	0	-
5119900 Total					**740**	**11**	**193**	**58**	**105**	**328**	**44**	**0**	**-**
5120000	MANT OF BOILR PLNT	STEX	Steam O&M Expense	SG	12,615	185	3,289	989	1,790	5,600	758	4	-
5120000 Total					**12,615**	**185**	**3,289**	**989**	**1,790**	**5,600**	**758**	**4**	**-**
5121000	MNT BOILR-AIR HTR	STEX	Steam O&M Expense	SG	5,103	75	1,330	400	724	2,266	307	1	-
5121000 Total					**5,103**	**75**	**1,330**	**400**	**724**	**2,266**	**307**	**1**	**-**
5121100	MNT BOILR-CHEM FD	STEX	Steam O&M Expense	SG	166	2	43	13	24	74	10	0	-
5121100 Total					**166**	**2**	**43**	**13**	**24**	**74**	**10**	**0**	**-**
5121200	MNT BOILR-CL HANDL	STEX	Steam O&M Expense	SG	4,249	62	1,108	333	603	1,886	255	1	-
5121200 Total					**4,249**	**62**	**1,108**	**333**	**603**	**1,886**	**255**	**1**	**-**
5121400	MNT BOIL-DEMINERLZ	STEX	Steam O&M Expense	SG	413	6	108	32	59	183	25	0	-
5121400 Total					**413**	**6**	**108**	**32**	**59**	**183**	**25**	**0**	**-**
5121500	MNT BOIL-EXTRC STM	STEX	Steam O&M Expense	SG	322	5	84	25	46	143	19	0	-
5121500 Total					**322**	**5**	**84**	**25**	**46**	**143**	**19**	**0**	**-**
5121600	MNT BOILR-FLYASH	STEX	Steam O&M Expense	SG	3,656	54	953	287	519	1,623	220	1	-
5121600 Total					**3,656**	**54**	**953**	**287**	**519**	**1,623**	**220**	**1**	**-**
5121700	MNT BOIL-FUEL OIL	STEX	Steam O&M Expense	SG	618	9	161	48	88	274	37	0	-
5121700 Total					**618**	**9**	**161**	**48**	**88**	**274**	**37**	**0**	**-**
5121800	MNT BOIL-FEEDWATR	STEX	Steam O&M Expense	SG	3,610	53	941	283	512	1,603	217	1	-
5121800 Total					**3,610**	**53**	**941**	**283**	**512**	**1,603**	**217**	**1**	**-**
5121900	MNT BOIL-FRZ PRTEC	STEX	Steam O&M Expense	SG	78	1	20	6	11	34	5	0	-
5121900 Total					**78**	**1**	**20**	**6**	**11**	**34**	**5**	**0**	**-**
5122000	MNT BOILR-AUX SYST	STEX	Steam O&M Expense	SG	451	7	118	35	64	200	27	0	-
5122000 Total					**451**	**7**	**118**	**35**	**64**	**200**	**27**	**0**	**-**
5122100	MNT BOILR-MAIN STM	STEX	Steam O&M Expense	SG	2,197	32	573	172	312	975	132	1	-

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
5122100 Total					**2,197**	**32**	**573**	**172**	**312**	**975**	**132**	**1**	**-**
5122200	MNT BOIL-PLVRZD CL	STEX	Steam O&M Expense	SG	6,187	91	1,613	485	878	2,747	372	2	-
5122200 Total					**6,187**	**91**	**1,613**	**485**	**878**	**2,747**	**372**	**2**	**-**
5122300	MNT BOIL-PRECIP/BAG	STEX	Steam O&M Expense	SG	3,011	44	785	236	427	1,337	181	1	-
5122300 Total					**3,011**	**44**	**785**	**236**	**427**	**1,337**	**181**	**1**	**-**
5122400	MNT BOIL-PRTRT WTR	STEX	Steam O&M Expense	SG	287	4	75	22	41	127	17	0	-
5122400 Total					**287**	**4**	**75**	**22**	**41**	**127**	**17**	**0**	**-**
5122500	MNT BOIL-RV OSMSIS	STEX	Steam O&M Expense	SG	154	2	40	12	22	68	9	0	-
5122500 Total					**154**	**2**	**40**	**12**	**22**	**68**	**9**	**0**	**-**
5122600	MNT BOIL-RHEAT ST	STEX	Steam O&M Expense	SG	465	7	121	36	66	206	28	0	-
5122600 Total					**465**	**7**	**121**	**36**	**66**	**206**	**28**	**0**	**-**
5122800	MNT BOIL-SOOTBLWG	STEX	Steam O&M Expense	SG	2,008	29	523	157	285	891	121	1	-
5122800 Total					**2,008**	**29**	**523**	**157**	**285**	**891**	**121**	**1**	**-**
5122900	MNT BOILR-SCRUBBER	STEX	Steam O&M Expense	SG	6,072	89	1,583	476	862	2,696	365	2	-
5122900 Total					**6,072**	**89**	**1,583**	**476**	**862**	**2,696**	**365**	**2**	**-**
5123000	MNT BOILR-BOTM ASH	STEX	Steam O&M Expense	SG	2,632	39	686	206	374	1,168	158	1	-
5123000 Total					**2,632**	**39**	**686**	**206**	**374**	**1,168**	**158**	**1**	**-**
5123100	MNT BOIL-WTR TRTMT	STEX	Steam O&M Expense	SG	432	6	113	34	61	192	26	0	-
5123100 Total					**432**	**6**	**113**	**34**	**61**	**192**	**26**	**0**	**-**
5123200	MNT BOIL-CNTL SUPT	STEX	Steam O&M Expense	SG	777	11	203	61	110	345	47	0	-
5123200 Total					**777**	**11**	**203**	**61**	**110**	**345**	**47**	**0**	**-**
5123300	MAINT GEO GATH SYS	STEX	Steam O&M Expense	SG	260	4	68	20	37	115	16	0	-
5123300 Total					**260**	**4**	**68**	**20**	**37**	**115**	**16**	**0**	**-**
5123400	MAINT OF BOILERS	STEX	Steam O&M Expense	SG	1,715	25	447	134	243	761	103	1	-
5123400 Total					**1,715**	**25**	**447**	**134**	**243**	**761**	**103**	**1**	**-**
5124000	MNT BOILR-CONTROLS	STEX	Steam O&M Expense	SG	1,130	17	295	89	160	502	68	0	-
5124000 Total					**1,130**	**17**	**295**	**89**	**160**	**502**	**68**	**0**	**-**
5125000	MNT BOILER-DRAFT	STEX	Steam O&M Expense	SG	2,644	39	689	207	375	1,174	159	1	-
5125000 Total					**2,644**	**39**	**689**	**207**	**375**	**1,174**	**159**	**1**	**-**
5126000	MNT BOILR-FIRESIDE	STEX	Steam O&M Expense	SG	1,430	21	373	112	203	635	86	0	-
5126000 Total					**1,430**	**21**	**373**	**112**	**203**	**635**	**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	1,600	481	871	2,724	369	2	-
5128000 Total					**6,137**	**90**	**1,600**	**481**	**871**	**2,724**	**369**	**2**	**-**
5129000	MNT BOIL-COMP AIR	STEX	Steam O&M Expense	SG	326	5	85	26	46	145	20	0	-
5129000 Total					**326**	**5**	**85**	**26**	**46**	**145**	**20**	**0**	**-**
5129900	MAINT BOILER-MISC	STEX	Steam O&M Expense	SG	366	5	95	29	52	162	22	0	-
5129900 Total					**366**	**5**	**95**	**29**	**52**	**162**	**22**	**0**	**-**
5130000	MAINT ELEC PLANT	STEX	Steam O&M Expense	SG	4,008	59	1,045	314	569	1,779	241	1	-
5130000 Total					**4,008**	**59**	**1,045**	**314**	**569**	**1,779**	**241**	**1**	**-**
5131000	MAINT ELEC AC	STEX	Steam O&M Expense	SG	15,840	232	4,130	1,242	2,248	7,032	951	5	-
5131000 Total					**15,840**	**232**	**4,130**	**1,242**	**2,248**	**7,032**	**951**	**5**	**-**
5131100	MAINT/LUBE-OIL SYS	STEX	Steam O&M Expense	SG	656	10	171	51	93	291	39	0	-
5131100 Total					**656**	**10**	**171**	**51**	**93**	**291**	**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	1,280	385	697	2,179	295	1	-
5131400 Total					**4,908**	**72**	**1,280**	**385**	**697**	**2,179**	**295**	**1**	**-**
5132000	MAINT ALARMS/INFO	STEX	Steam O&M Expense	SG	1,476	22	385	116	209	655	89	0	-
5132000 Total					**1,476**	**22**	**385**	**116**	**209**	**655**	**89**	**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	454	61	0	-
5135000 Total					**1,022**	**15**	**266**	**80**	**145**	**454**	**61**	**0**	**-**
5137000	MAINT-COOLING TOWR	STEX	Steam O&M Expense	SG	1,835	27	479	144	261	815	110	1	-
5137000 Total					**1,835**	**27**	**479**	**144**	**261**	**815**	**110**	**1**	**-**
5138000	MAINT-CIRCUL WATER	STEX	Steam O&M Expense	SG	1,101	16	287	86	156	489	66	0	-
5138000 Total					**1,101**	**16**	**287**	**86**	**156**	**489**	**66**	**0**	**-**
5139000	MAINT-ELECT - DC	STEX	Steam O&M Expense	SG	242	4	63	19	34	107	15	0	-
5139000 Total					**242**	**4**	**63**	**19**	**34**	**107**	**15**	**0**	**-**
5139900	MNT ELEC PLT-MISC	STEX	Steam O&M Expense	SG	25	0	6	2	4	11	1	0	-

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
5139900 Total					**25**	**0**	**6**	**2**	**4**	**11**	**1**	**0**	**-**
5140000	MAINT MISC STM PLN	STEX	Steam O&M Expense	SG	4,710	69	1,228	369	668	2,091	283	1	-
5140000 Total					**4,710**	**69**	**1,228**	**369**	**668**	**2,091**	**283**	**1**	**-**
5141000	MISC STM-COMP AIR	STEX	Steam O&M Expense	SG	1,526	22	398	120	217	677	92	0	-
5141000 Total					**1,526**	**22**	**398**	**120**	**217**	**677**	**92**	**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	199	27	0	-
5145000 Total					**449**	**7**	**117**	**35**	**64**	**199**	**27**	**0**	**-**
5146000	MAINT/PAGING SYS	STEX	Steam O&M Expense	SG	237	3	62	19	34	105	14	0	-
5146000 Total					**237**	**3**	**62**	**19**	**34**	**105**	**14**	**0**	**-**
5147000	MAINT/PLANT EQUIP	STEX	Steam O&M Expense	SG	1,206	18	314	95	171	535	72	0	-
5147000 Total					**1,206**	**18**	**314**	**95**	**171**	**535**	**72**	**0**	**-**
5148000	MAINT/PLT-VEHICLES	STEX	Steam O&M Expense	SG	1,987	29	518	156	282	882	119	1	-
5148000 Total					**1,987**	**29**	**518**	**156**	**282**	**882**	**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	375	113	204	639	86	0	-
5149500 Total					**1,439**	**21**	**375**	**113**	**204**	**639**	**86**	**0**	**-**
5350000	OPER SUPERV & ENG	HYEX	Hydro O&M Expense	SG-P	9,462	139	2,467	742	1,343	4,200	568	3	-
5350000	OPER SUPERV & ENG	HYEX	Hydro O&M Expense	SG-U	1,638	24	427	128	232	727	98	0	-
5350000 Total					**11,099**	**163**	**2,894**	**870**	**1,575**	**4,928**	**667**	**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	713	214	388	1,214	164	1	-
5370000 Total					**2,734**	**40**	**713**	**214**	**388**	**1,214**	**164**	**1**	**-**
5371000	HYDRO/FISH & WILD	HYEX	Hydro O&M Expense	SG-P	539	8	141	42	77	239	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**	**93**	**290**	**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	89	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**	**59**	**18**	**32**	**100**	**13**	**0**	**-**
5379000	HYDRO EXPENSE-OTH	HYEX	Hydro O&M Expense	SG-P	490	7	128	38	70	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**	**175**	**53**	**95**	**298**	**40**	**0**	**-**
5390000	MSC HYD PWR GEN EX	HYEX	Hydro O&M Expense	SG-P	11,779	173	3,071	923	1,672	5,229	707	3	-
5390000	MSC HYD PWR GEN EX	HYEX	Hydro O&M Expense	SG-U	6,544	96	1,706	513	929	2,905	393	2	-
5390000 Total					**18,323**	**269**	**4,777**	**1,436**	**2,601**	**8,134**	**1,100**	**5**	**-**
5400000	RENTS (HYDRO GEN)	HYEX	Hydro O&M Expense	SG-P	1,430	21	373	112	203	635	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**	**389**	**117**	**212**	**663**	**90**	**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	194	58	105	330	45	0	-
5420000	MAINT OF STRUCTURE	HYEX	Hydro O&M Expense	SG-U	73	1	19	6	10	32	4	0	-
5420000 Total					**815**	**12**	**213**	**64**	**116**	**362**	**49**	**0**	**-**
5430000	MNT DAMS & WTR SYS	HYEX	Hydro O&M Expense	SG-P	694	10	181	54	98	308	42	0	-
5430000	MNT DAMS & WTR SYS	HYEX	Hydro O&M Expense	SG-U	355	5	93	28	50	158	21	0	-
5430000 Total					**1,049**	**15**	**273**	**82**	**149**	**466**	**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	269	81	146	458	62	0	-
5441000	PRIME MOVERS & GEN	HYEX	Hydro O&M Expense	SG-U	98	1	25	8	14	43	6	0	-
5441000 Total					**1,129**	**17**	**294**	**88**	**160**	**501**	**68**	**0**	**-**
5442000	ACCESS ELEC EQUIP	HYEX	Hydro O&M Expense	SG-P	597	9	156	47	85	265	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**	**295**	**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	45	81	252	34	0	-
5451000 Total					**568**	**8**	**148**	**45**	**81**	**252**	**34**	**0**	**-**

Exhibit PAC/1002
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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
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	240	72	130	408	55	0	-
5455000	MAINT-RDS/TRAIL/BR	HYEX	Hydro O&M Expense	SG-U	441	6	115	35	63	196	26	0	-
5455000 Total					**1,360**	**20**	**355**	**107**	**193**	**604**	**82**	**0**	**-**
5459000	MAINT HYDRO-OTHER	HYEX	Hydro O&M Expense	SG	33,000	484	8,603	2,587	4,684	14,650	1,982	10	-
5459000	MAINT HYDRO-OTHER	HYEX	Hydro O&M Expense	SG-P	1,417	21	369	111	201	629	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**	**511**	**9,076**	**2,729**	**4,941**	**15,455**	**2,091**	**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	84	25	45	142	19	0	-
5460000 Total					**320**	**5**	**84**	**25**	**45**	**142**	**19**	**0**	**-**
5471000	NATURAL GAS	NPCX	Net Power Cost Expense	SE	291,053	4,113	72,961	21,474	44,922	128,785	18,697	99	-
5471000 Total					**291,053**	**4,113**	**72,961**	**21,474**	**44,922**	**128,785**	**18,697**	**99**	**-**
5480000	GENERATION EXP	OPEX	Other Production O&M Expense	SG	18,033	265	4,701	1,414	2,559	8,006	1,083	5	-
5480000 Total					**18,033**	**265**	**4,701**	**1,414**	**2,559**	**8,006**	**1,083**	**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	2,223	668	1,210	3,785	512	2	-
5490000 Total					**8,558**	**125**	**2,255**	**668**	**1,210**	**3,785**	**512**	**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	110	1,946	585	1,059	3,314	448	2	-
5500000 Total					**7,842**	**110**	**2,324**	**585**	**1,059**	**3,314**	**448**	**2**	**-**
5520000	MAINT OF STRUCTURE	OPEX	Other Production O&M Expense	SG	2,353	35	614	184	334	1,045	141	1	-
5520000 Total					**2,353**	**35**	**614**	**184**	**334**	**1,045**	**141**	**1**	**-**
5530000	MNT GEN & ELEC PLT	OPEX	Other Production O&M Expense	SG	15,161	222	3,953	1,188	2,152	6,731	911	4	-
5530000 Total					**15,161**	**222**	**3,953**	**1,188**	**2,152**	**6,731**	**911**	**4**	**-**
5540000	MNT MSC OTH PWR GN	OPEX	Other Production O&M Expense	SG	1,128	17	294	88	160	501	68	0	-
5540000 Total					**1,128**	**17**	**294**	**88**	**160**	**501**	**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	514	154	280	875	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**	**514**	**154**	**280**	**875**	**118**	**1**	**-**
5550000	PURCHASED POWER	PSEX	Power Supply Expense	SG	674	10	176	53	96	299	41	0	-
5550000 Total					**674**	**10**	**176**	**53**	**96**	**299**	**41**	**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	887	15,738	4,632	9,690	27,780	4,033	21	-
5552500 Total					**62,782**	**887**	**15,738**	**4,632**	**9,690**	**27,780**	**4,033**	**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	3,671	65,218	19,610	35,506	111,058	15,024	73	-
5555900 Total					**250,160**	**3,671**	**65,218**	**19,610**	**35,506**	**111,058**	**15,024**	**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	6,594	117,168	35,230	63,789	199,524	26,992	132	-
5556300 Total					**449,429**	**6,594**	**117,168**	**35,230**	**63,789**	**199,524**	**26,992**	**132**	**-**
5556400	FIRM DEMAND PURCH	NPCX	Net Power Cost Expense	SG	35,434	520	9,238	2,778	5,029	15,731	2,128	10	-
5556400 Total					**35,434**	**520**	**9,238**	**2,778**	**5,029**	**15,731**	**2,128**	**10**	**-**
5556700	POST-MERG FIRM PUR	NPCX	Net Power Cost Expense	SG	(51,310)	(753)	(13,377)	(4,022)	(7,283)	(22,779)	(3,082)	(15)	-
5556700 Total					**(51,310)**	**(753)**	**(13,377)**	**(4,022)**	**(7,283)**	**(22,779)**	**(3,082)**	**(15)**	**-**
5556710	EIM - FIRM PURCHASES	NPCX	Net Power Cost Expense	SG	(64,885)	(952)	(16,916)	(5,086)	(9,209)	(28,806)	(3,897)	(19)	-
5556710 Total					**(64,885)**	**(952)**	**(16,916)**	**(5,086)**	**(9,209)**	**(28,806)**	**(3,897)**	**(19)**	**-**
5558000	PUR PWR-UNDR CAP LEA	NPCX	Net Power Cost Expense	SG	1,507	22	393	118	214	669	91	0	-
5558000 Total					**1,507**	**22**	**393**	**118**	**214**	**669**	**91**	**0**	**-**
5560000	SYS CTRL & LD DISP	PSEX	Power Supply Expense	SG	596	9	155	47	85	265	36	0	-
5560000 Total					**596**	**9**	**155**	**47**	**85**	**265**	**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	513	9,123	2,743	4,967	15,535	2,102	10	-
5570000 Total					**35,001**	**514**	**9,125**	**2,744**	**4,968**	**15,539**	**2,102**	**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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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
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	132	2,342	704	1,275	3,989	540	3	-
5600000 Total					8,985	132	2,342	704	1,275	3,989	540	3	-
5612000	LD - MONITOR & OPER	TNEX	Transmission O&M Expense	SG	7,132	105	1,859	559	1,012	3,166	428	2	-
5612000 Total					7,132	105	1,859	559	1,012	3,166	428	2	-
5614000	SCHED, SYS CTR & DSP	TNEX	Transmission O&M Expense	SG	327	5	85	26	46	145	20	0	-
5614000 Total					327	5	85	26	46	145	20	0	-
5614010	EIM - SCHEDULING,SYS	TNEX	Transmission O&M Expense	SG	754	11	196	59	107	335	45	0	-
5614010 Total					754	11	196	59	107	335	45	0	-
5615000	REL PLAN & STDS DEV	TNEX	Transmission O&M Expense	SG	2,396	35	625	188	340	1,064	144	1	-
5615000 Total					2,396	35	625	188	340	1,064	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	326	98	177	555	75	0	-
5617000 Total					1,250	18	326	98	177	555	75	0	-
5618000	REL PLN & STAND SVCS	TNEX	Transmission O&M Expense	SG	5,785	85	1,508	453	821	2,568	347	2	-
5618000 Total					5,785	85	1,508	453	821	2,568	347	2	-
5620000	STATION EXP(TRANS)	TNEX	Transmission O&M Expense	SG	3,230	47	842	253	458	1,434	194	1	-
5620000 Total					3,230	47	842	253	458	1,434	194	1	-
5630000	OVERHEAD LINE EXP	TNEX	Transmission O&M Expense	SG	961	14	251	75	136	427	58	0	-
5630000 Total					961	14	251	75	136	427	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	34	596	179	325	1,015	137	1	-
5650010 Total					2,287	34	596	179	325	1,015	137	1	-
5651000	S/T FIRM WHEELING	NPCX	Net Power Cost Expense	SG	6,362	93	1,659	499	903	2,824	382	2	-
5651000 Total					6,362	93	1,659	499	903	2,824	382	2	-
5652500	NON-FIRM WHEEL EXP	NPCX	Net Power Cost Expense	SE	15,972	226	4,004	1,178	2,465	7,067	1,026	5	-
5652500 Total					15,972	226	4,004	1,178	2,465	7,067	1,026	5	-
5654600	POST-MRG WHEEL EXP	NPCX	Net Power Cost Expense	SG	124,770	1,831	32,528	9,781	17,709	55,392	7,494	37	-
5654600 Total					124,770	1,831	32,528	9,781	17,709	55,392	7,494	37	-
5660000	MISC TRANS EXPENSE	TNEX	Transmission O&M Expense	SG	3,609	53	941	283	512	1,602	217	1	-
5660000 Total					3,609	53	941	283	512	1,602	217	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	647	195	352	1,102	149	1	-
5670000 Total					2,482	36	647	195	352	1,102	149	1	-
5680000	MNT SUPERV & ENG	TNEX	Transmission O&M Expense	SG	845	12	220	66	120	375	51	0	-
5680000 Total					845	12	220	66	120	375	51	0	-
5690000	MAINT OF STRUCTURE	TNEX	Transmission O&M Expense	SG	95	1	25	7	14	42	6	0	-
5690000 Total					95	1	25	7	14	42	6	0	-
5692000	MAINT-COMP SW TRANS	TNEX	Transmission O&M Expense	SG	700	10	183	55	99	311	42	0	-
5692000 Total					700	10	183	55	99	311	42	0	-
5693000	MAINT-COM EQP TRANS	TNEX	Transmission O&M Expense	SG	4,445	65	1,159	348	631	1,973	267	1	-
5693000 Total					4,445	65	1,159	348	631	1,973	267	1	-
5700000	MAINT STATION EQIP	TNEX	Transmission O&M Expense	SG	10,323	151	2,691	809	1,465	4,583	620	3	-
5700000 Total					10,323	151	2,691	809	1,465	4,583	620	3	-
5710000	MAINT OVHD LINES	TNEX	Transmission O&M Expense	SG	17,663	259	4,605	1,385	2,507	7,841	1,061	5	-
5710000 Total					17,663	259	4,605	1,385	2,507	7,841	1,061	5	-
5720000	MNT UNDERGRD LINES	TNEX	Transmission O&M Expense	SG	170	2	44	13	24	75	10	0	-
5720000 Total					170	2	44	13	24	75	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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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
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	-	-

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
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	-	-	-	-	-

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
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**	**-**	**-**

PACIFICORP

Operations & Maintenance Expense (Actuals)
Sum of Range: 07/2020 - 06/2021
Allocation Method - Factor 2020 Protocol
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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
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	1,686	20,779	5,870	10,053	33,596	4,467	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**	**1,686**	**21,481**	**5,870**	**10,448**	**34,784**	**4,467**	**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	2,236	632	1,082	3,616	481	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**	**186**	**4,074**	**645**	**1,112**	**3,736**	**908**	**2**	**-**
9220000	A&G EXP TRANSF-CR	AGEX	Administrative & General Expense	SO	(37,447)	(826)	(10,175)	(2,875)	(4,923)	(16,452)	(2,188)	(8)	-
9220000 Total					**(37,447)**	**(826)**	**(10,175)**	**(2,875)**	**(4,923)**	**(16,452)**	**(2,188)**	**(8)**	**-**

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
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	303	3,731	1,054	1,805	6,032	802	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**	**3,848**	**1,064**	**2,005**	**6,556**	**803**	**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	2,444	690	1,182	3,951	525	2	-
9239990 Total					**9,105**	**198**	**2,557**	**690**	**1,182**	**3,951**	**525**	**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	1,188	336	575	1,921	255	1	-
9243000 Total					**4,372**	**96**	**1,188**	**336**	**575**	**1,921**	**255**	**1**	**-**
9250000	INJURIES & DAMAGES	AGEX	Administrative & General Expense	SO	153,085	3,376	41,598	11,752	20,126	67,259	8,944	32	-
9250000 Total					**153,085**	**3,376**	**41,598**	**11,752**	**20,126**	**67,259**	**8,944**	**32**	**-**
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)	(652)	(87)	(0)	-
9251000 Total					**-**	**(33)**	**1,081**	**(114)**	**(195)**	**(652)**	**(87)**	**(0)**	**-**
9261200	PEN EXP-OTH NBC	AGEX	Administrative & General Expense	SO	(6,607)	(146)	(1,795)	(507)	(869)	(2,903)	(386)	(1)	-
9261200 Total					**(6,607)**	**(146)**	**(1,795)**	**(507)**	**(869)**	**(2,903)**	**(386)**	**(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)	(781)	(221)	(378)	(1,262)	(168)	(1)	-
9262200 Total					**(2,873)**	**(63)**	**(781)**	**(221)**	**(378)**	**(1,262)**	**(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	752	212	364	1,216	162	1	-
9263200 Total					**2,768**	**61**	**752**	**212**	**364**	**1,216**	**162**	**1**	**-**
9269100	GROSS-UP - PENSION	AGEX	Administrative & General Expense	SO	8,149	180	2,214	626	1,071	3,580	476	2	-
9269100 Total					**8,149**	**180**	**2,214**	**626**	**1,071**	**3,580**	**476**	**2**	**-**
9269200	GROSS-UP - POST-RETR	AGEX	Administrative & General Expense	SO	947	21	257	73	125	416	55	0	-
9269200 Total					**947**	**21**	**257**	**73**	**125**	**416**	**55**	**0**	**-**
9269400	GROSS-UP - MD/DN/V/L	AGEX	Administrative & General Expense	SO	60,432	1,333	16,421	4,639	7,945	26,551	3,531	12	-
9269400 Total					**60,432**	**1,333**	**16,421**	**4,639**	**7,945**	**26,551**	**3,531**	**12**	**-**
9269500	GROSS-UP - 401(K) EX	AGEX	Administrative & General Expense	SO	39,571	873	10,753	3,038	5,202	17,386	2,312	8	-
9269500 Total					**39,571**	**873**	**10,753**	**3,038**	**5,202**	**17,386**	**2,312**	**8**	**-**
9269600	GROSS-UP - POST-EMPL	AGEX	Administrative & General Expense	SO	6,401	141	1,739	491	842	2,812	374	1	-
9269600 Total					**6,401**	**141**	**1,739**	**491**	**842**	**2,812**	**374**	**1**	**-**
9269700	GROSS-UP - OTH BEN E	AGEX	Administrative & General Expense	SO	5,779	127	1,570	444	760	2,539	338	1	-
9269700 Total					**5,779**	**127**	**1,570**	**444**	**760**	**2,539**	**338**	**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	609	172	294	984	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**	**2,629**	**295**	**1,433**	**1,852**	**335**	**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	1,118	336	609	1,904	258	1	-
9283000 Total					**4,290**	**63**	**1,118**	**336**	**609**	**1,904**	**258**	**1**	**-**
9290000	DUPLICATE CHRGS-CR	AGEX	Administrative & General Expense	SO	(3,458)	(76)	(940)	(265)	(455)	(1,519)	(202)	(1)	-
9290000 Total					**(3,458)**	**(76)**	**(940)**	**(265)**	**(455)**	**(1,519)**	**(202)**	**(1)**	**-**
9299100	DUP CHG CR - PENSION	AGEX	Administrative & General Expense	SO	(8,149)	(180)	(2,214)	(626)	(1,071)	(3,580)	(476)	(2)	-
9299100 Total					**(8,149)**	**(180)**	**(2,214)**	**(626)**	**(1,071)**	**(3,580)**	**(476)**	**(2)**	**-**
9299200	DUP CHG CR - POST-RT	AGEX	Administrative & General Expense	SO	(947)	(21)	(257)	(73)	(125)	(416)	(55)	(0)	-
9299200 Total					**(947)**	**(21)**	**(257)**	**(73)**	**(125)**	**(416)**	**(55)**	**(0)**	**-**
9299400	DUP CHG CR - M/D/V/L	AGEX	Administrative & General Expense	SO	(60,432)	(1,333)	(16,421)	(4,639)	(7,945)	(26,551)	(3,531)	(12)	-
9299400 Total					**(60,432)**	**(1,333)**	**(16,421)**	**(4,639)**	**(7,945)**	**(26,551)**	**(3,531)**	**(12)**	**-**
9299500	DUP CHRG CR - 401(K)	AGEX	Administrative & General Expense	SO	(39,571)	(873)	(10,753)	(3,038)	(5,202)	(17,386)	(2,312)	(8)	-
9299500 Total					**(39,571)**	**(873)**	**(10,753)**	**(3,038)**	**(5,202)**	**(17,386)**	**(2,312)**	**(8)**	**-**
9299600	DUP CHG CR - POST-EM	AGEX	Administrative & General Expense	SO	(6,401)	(141)	(1,739)	(491)	(842)	(2,812)	(374)	(1)	-
9299600 Total					**(6,401)**	**(141)**	**(1,739)**	**(491)**	**(842)**	**(2,812)**	**(374)**	**(1)**	**-**
9299700	DUP CHG CR - OTH BEN	AGEX	Administrative & General Expense	SO	(5,779)	(127)	(1,570)	(444)	(760)	(2,539)	(338)	(1)	-
9299700 Total					**(5,779)**	**(127)**	**(1,570)**	**(444)**	**(760)**	**(2,539)**	**(338)**	**(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	605	171	293	979	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**	**606**	**171**	**312**	**982**	**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	560	158	271	905	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**	**1,015**	**169**	**417**	**1,275**	**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	7,091	2,003	3,431	11,466	1,525	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**	**7,250**	**2,079**	**3,446**	**11,512**	**1,532**	**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**	**57,174**	**814,402**	**220,908**	**408,582**	**1,303,434**	**181,333**	**791**	**105,540**

B3.
DEPRECIATION
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	360	49	0	-
4030000	DEPN EXPENSE-ELECT	3110000	STRUCTURES AND IMPROVEMENTS	SG	36,945	542	9,632	2,896	5,244	16,402	2,219	11	-
4030000	DEPN EXPENSE-ELECT	3120000	BOILER PLANT EQUIPMENT	SG	199,347	2,925	51,970	15,627	28,294	88,500	11,973	58	-
4030000	DEPN EXPENSE-ELECT	3140000	TURBOGENERATOR UNITS	SG	41,422	608	10,799	3,247	5,879	18,389	2,488	12	-
4030000	DEPN EXPENSE-ELECT	3150000	ACCESSORY ELECTRIC EQUIPMENT	SG	16,451	241	4,289	1,290	2,335	7,304	988	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	23	400	120	218	681	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	151	20	0	-
4030000	DEPN EXPENSE-ELECT	3312000	STRUCTURES AND IMPROVE-FISH/WILDLIFE	SG-P	9,512	140	2,480	746	1,350	4,223	571	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	234	70	127	398	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	262	79	142	445	60	0	-
4030000	DEPN EXPENSE-ELECT	3321000	"RESERVOIRS, DAMS, & WTRWYS-PRODUCTION"	SG-P	13,169	193	3,433	1,032	1,869	5,847	791	4	-
4030000	DEPN EXPENSE-ELECT	3321000	"RESERVOIRS, DAMS, & WTRWYS-PRODUCTION"	SG-U	3,627	53	946	284	515	1,610	218	1	-
4030000	DEPN EXPENSE-ELECT	3322000	"RESERVOIRS, DAMS, & WTRWYS-FISH/WILDLIF	SG-P	7,790	114	2,031	611	1,106	3,458	468	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)	(65)	(1,149)	(345)	(625)	(1,956)	(265)	(1)	-
4030000	DEPN EXPENSE-ELECT	3330000	"WATER WHEELS, TURB & GENERATORS"	SG-U	2,087	31	544	164	296	927	125	1	-
4030000	DEPN EXPENSE-ELECT	3340000	ACCESSORY ELECTRIC EQUIPMENT	SG-P	(5,370)	(79)	(1,400)	(421)	(762)	(2,384)	(323)	(2)	-
4030000	DEPN EXPENSE-ELECT	3340000	ACCESSORY ELECTRIC EQUIPMENT	SG-U	632	9	165	50	90	281	38	0	-
4030000	DEPN EXPENSE-ELECT	3347000	ACCESSORY ELECT EQUIP - SUPV & ALARM	SG-P	(1,049)	(15)	(273)	(82)	(149)	(466)	(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	189	26	0	-
4030000	DEPN EXPENSE-ELECT	3360000	"ROADS, RAILROADS & BRIDGES"	SG-U	114	2	30	9	16	50	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	105	1,858	559	1,012	3,165	428	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	74	230	31	0	-
4030000	DEPN EXPENSE-ELECT	3430000	PRIME MOVERS	SG	125,254	1,838	32,654	9,819	17,778	55,606	7,523	37	-
4030000	DEPN EXPENSE-ELECT	3440000	GENERATORS	SG	18,779	276	4,896	1,472	2,665	8,337	1,128	5	-
4030000	DEPN EXPENSE-ELECT	3440000	GENERATORS	UT	3	-	-	-	-	3	-	-	-
4030000	DEPN EXPENSE-ELECT	3450000	ACCESSORY ELECTRIC EQUIPMENT	SG	11,241	165	2,930	881	1,595	4,990	675	3	-
4030000	DEPN EXPENSE-ELECT	3450000	ACCESSORY ELECTRIC EQUIPMENT	UT	1	-	-	-	-	1	-	-	-
4030000	DEPN EXPENSE-ELECT	3460000	MISCELLANEOUS PWR PLANT EQUIP	SG	589	9	154	46	84	261	35	0	-
4030000	DEPN EXPENSE-ELECT	3502000	LAND RIGHTS	SG	2,724	40	710	214	387	1,209	164	1	-
4030000	DEPN EXPENSE-ELECT	3520000	STRUCTURES & IMPROVEMENTS	SG	4,190	61	1,092	328	595	1,860	252	1	-
4030000	DEPN EXPENSE-ELECT	3530000	STATION EQUIPMENT	SG	36,727	539	9,575	2,879	5,213	16,305	2,206	11	-
4030000	DEPN EXPENSE-ELECT	3534000	STATION EQUIPMENT, STEP-UP TRANSFORMERS	SG	2,938	43	766	230	417	1,304	176	1	-
4030000	DEPN EXPENSE-ELECT	3537000	STATION EQUIPMENT-SUPERVISORY & ALARM	SG	406	6	106	32	58	180	24	0	-
4030000	DEPN EXPENSE-ELECT	3540000	TOWERS AND FIXTURES	SG	19,676	289	5,130	1,542	2,793	8,735	1,182	6	-
4030000	DEPN EXPENSE-ELECT	3550000	POLES AND FIXTURES	SG	22,835	335	5,953	1,790	3,241	10,138	1,371	7	-
4030000	DEPN EXPENSE-ELECT	3560000	OVERHEAD CONDUCTORS & DEVICES	SG	24,728	363	6,447	1,938	3,510	10,978	1,485	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	-	-	-	-	-

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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	54	16	29	91	12	0	-
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	SO	1,942	43	528	149	255	853	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	76	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	38	68	213	29	0	-
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	SO	9,187	203	2,496	705	1,208	4,036	537	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	-	-	-	-

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	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	241	72	131	410	56	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	5	9	27	4	0	-
4030000	DEPN EXPENSE-ELECT	3950000	LABORATORY EQUIPMENT	SG	321	5	84	25	46	142	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	2,015	606	1,097	3,431	464	2	-
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	SO	4,099	90	1,114	315	539	1,801	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	158	21	0	-
4030000	DEPN EXPENSE-ELECT	3972000	MOBILE RADIO EQUIPMENT	SO	44	1	12	3	6	19	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	62	8	0	-
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	SO	110	2	30	8	14	48	6	0	-

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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**	**17,594**	**225,216**	**65,285**	**114,477**	**368,227**	**48,929**	**183**	**-**
4032000	DEPR - STEAM	565131	DEPR - PROD STEAM NOT CLASSIFIED	SG	9,065	133	2,363	711	1,287	4,024	544	3	-
4032000	DEPR - STEAM	565247	Depr - Prod Steam UT STEP	OTHER	180,756	-	-	-	-	-	-	-	180,756
4032000 Total					**189,821**	**133**	**2,363**	**711**	**1,287**	**4,024**	**544**	**3**	**180,756**
4033000	DEPR - HYDRO	565133	DEPR - PROD HYDRO NOT CLASSIFIED	SG-P	872	13	227	68	124	387	52	0	-
4033000	DEPR - HYDRO	565133	DEPR - PROD HYDRO NOT CLASSIFIED	SG-U	82	1	21	6	12	36	5	0	-
4033000 Total					**954**	**14**	**249**	**75**	**135**	**424**	**57**	**0**	**-**
4034000	DEPR - OTHER	565134	DEPR - PROD OTHER NOT CLASSIFIED	SG	249	4	65	20	35	111	15	0	-
4034000 Total					**249**	**4**	**65**	**20**	**35**	**111**	**15**	**0**	**-**
4035000	DEPR-TRANSMISSION	565141	DEPR - TRANS ASSETS NOT CLASSIFIED	SG	10,800	158	2,816	847	1,533	4,795	649	3	-
4035000 Total					**10,800**	**158**	**2,816**	**847**	**1,533**	**4,795**	**649**	**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	956	287	520	1,627	220	1	-
4037000 Total					**3,666**	**54**	**956**	**287**	**520**	**1,627**	**220**	**1**	**-**
4039999	DEPR EXP-ELEC, OTH	565970	DEPRECIATION-JOINT OWNER BILLED-CREDIT	SG	(222)	(3)	(58)	(17)	(31)	(98)	(13)	(0)	-
4039999 Total					**(222)**	**(3)**	**(58)**	**(17)**	**(31)**	**(98)**	**(13)**	**(0)**	**-**
Grand Total					**1,035,081**	**18,055**	**232,581**	**67,750**	**117,309**	**369,083**	**49,356**	**191**	**180,756**

B4. AMORTIZATION EXPENSE

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	165	49	90	280	38	0	-
4040000	AMOR LTD TRM PLNT	3020000	FRANCHISES AND CONSENTS	SG-P	2,680	39	699	210	380	1,190	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	260	78	141	442	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	1,077	304	521	1,742	232	1	-
4040000	AMOR LTD TRM PLNT	3032130	PROD & TRANS PLANT	SG	109	2	28	9	15	48	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	56	8	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	15	2	0	-
4040000	AMOR LTD TRM PLNT	3032640	TIBCO SOFTWARE	SO	392	9	106	30	51	172	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	128	36	62	206	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	113	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	505	143	244	816	109	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	130	17	0	-
4040000	AMOR LTD TRM PLNT	3033090	STEAM PLANT INTANGIBLE ASSETS	SG	2,823	41	736	221	401	1,253	170	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	806	228	390	1,303	173	1	-
4040000	AMOR LTD TRM PLNT	3033230	VREALIZE VMWARE - SHARED	SO	202	4	55	16	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	618	174	299	999	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	160	2,834	852	1,543	4,827	653	3	-
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	SO	484	11	132	37	64	213	28	0	-
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	UT	4	-	-	-	-	4	-	-	-

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	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	138	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**	**931**	**13,623**	**3,693**	**5,876**	**21,769**	**2,638**	**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	1,694	509	922	2,884	390	2	-
4061000	EL PLNT ACQ ADJ-CM	566920	AMORT ELEC PLANT ACQ ADJ	UT	302	-	-	-	-	302	-	-	-
4061000 Total					**6,798**	**95**	**1,694**	**509**	**922**	**3,186**	**390**	**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**	**1,023**	**16,306**	**4,182**	**6,761**	**26,172**	**3,013**	**11**	**4,357**

B5. TAXES OTHER THAN INCOME

PACIFICORP

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)	(125)	(35)	(60)	(202)	(27)	(0)	-
4081000 Total					**(459)**	**(10)**	**(125)**	**(35)**	**(60)**	**(202)**	**(27)**	**(0)**	**-**
4081500	PROPERTY TAXES	579000	PROPERTY TAX	GPS	161,965	3,571	44,011	12,434	21,293	71,160	9,462	33	-
4081500	PROPERTY TAXES	579012	Property Tax Exp - Reg Deferral/Amortz	OR	(299)	-	(299)	-	-	-	-	-	-
4081500 Total					**161,666**	**3,571**	**43,712**	**12,434**	**21,293**	**71,160**	**9,462**	**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	3,713	1,049	1,796	6,003	798	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	94	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	24	68	10	0	-
4081990	MISC TAXES - OTHER	583273	Wyoming Wind Generation Tax	SG	2,232	33	582	175	317	991	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	115	34	71	203	29	0	-
4081990 Total					**18,402**	**347**	**6,018**	**1,311**	**2,343**	**7,389**	**990**	**4**	**-**
Grand Total					**212,197**	**5,132**	**79,098**	**13,710**	**25,439**	**78,356**	**10,425**	**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)	(1,847)	(32,824)	(9,870)	(17,870)	(55,896)	(7,562)	(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)**	**(1,848)**	**(32,836)**	**(9,873)**	**(17,878)**	**(55,917)**	**(7,565)**	**(37)**	**-**
4191000	AFUDC - OTHER	0	AFUDC - EQUITY	SNP	(79,166)	(1,649)	(20,265)	(5,904)	(10,408)	(36,227)	(4,687)	(17)	(8)
4191000 Total					**(79,166)**	**(1,649)**	**(20,265)**	**(5,904)**	**(10,408)**	**(36,227)**	**(4,687)**	**(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)	(610)	(172)	(295)	(986)	(131)	(0)	-
4211000 Total					**(1,734)**	**(49)**	**(99)**	**(172)**	**(295)**	**(986)**	**(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	7,688	94,477	27,523	48,525	168,890	21,853	78	39
4270000	INT ON LNG-TRM DBT	585002	INTEREST EXPENSE - LONG-TERM DEBT - MTNS	SNP	31,567	658	8,081	2,354	4,150	14,445	1,869	7	3
4270000	INT ON LNG-TRM DBT	585004	INTEREST EXPENSE - LT DEBT - PCRBS VARIA	SNP	314	7	80	23	41	143	19	0	0
4270000	INT ON LNG-TRM DBT	585005	INTEREST EXPENSE - LT DEBT - PCRB FEES &	SNP	774	16	198	58	102	354	46	0	0
4270000 Total					**401,728**	**8,369**	**102,837**	**29,959**	**52,818**	**183,833**	**23,787**	**84**	**43**
4280000	AMT DBT DISC & EXP	586160	AMORTIZATION - DEBT DISCOUNT	SNP	1,122	23	287	84	148	514	66	0	0
4280000	AMT DBT DISC & EXP	586170	AMORTIZATION - DEBT ISSUANCE EXP	SNP	3,398	71	870	253	447	1,555	201	1	0
4280000 Total					**4,521**	**94**	**1,157**	**337**	**594**	**2,069**	**268**	**1**	**0**
4281000	AMORTZN OF LOSS	586190	AMORTIZATION - LOSS ON REQACQUIRED DEBT	SNP	582	12	149	43	77	267	34	0	0
4281000 Total					**582**	**12**	**149**	**43**	**77**	**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	2,254	657	1,158	4,029	521	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**	**2,252**	**656**	**1,156**	**4,025**	**521**	**2**	**1**
4313000	INT EXP ON REG LIAB	0	INTEREST EXPENSE ON REG LIABILITIES	SNP	9,753	203	2,497	727	1,282	4,463	577	2	1
4313000 Total					**9,753**	**203**	**2,497**	**727**	**1,282**	**4,463**	**577**	**2**	**1**
4320000	AFUDC - BORROWED	585800	INTEREST CAPITALIZED (SEE OTH INCOME)	SNP	(44,281)	(922)	(11,335)	(3,302)	(5,822)	(20,263)	(2,622)	(9)	(5)
4320000	AFUDC - BORROWED	585860	INTEREST EXPENSE - AFUDC MANUAL ADJ	SNP	5,966	124	1,527	445	784	2,730	353	1	1
4320000 Total					**(38,315)**	**(798)**	**(9,808)**	**(2,857)**	**(5,038)**	**(17,533)**	**(2,269)**	**(8)**	**(4)**

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
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	538	152	260	870	116	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	22	37	123	16	0	0
SCHMAP	130755	Nondeductible Parking Costs	SO	830	18	226	64	109	365	49	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**	**965**	**273**	**470**	**1,564**	**208**	**1**	**21**
SCHMAT	105100	Capitalized Labor Costs	SO	4,075	90	1,107	313	536	1,791	238	1	0
SCHMAT	105120	Book Depreciation	SCHMDEXP	859,860	15,265	194,739	57,336	100,259	326,400	43,466	169	122,225
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	224	3,978	1,171	2,449	7,021	1,019	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	1,512	18,584	5,414	9,545	33,222	4,299	15	8
SCHMAT	105146	Capitalization of Test Energy	SG	2,663	39	694	209	378	1,182	160	1	0
SCHMAT	210200	Prepaid Taxes-property taxes	GPS	(4,930)	(109)	(1,340)	(378)	(648)	(2,166)	(288)	(1)	0
SCHMAT	220100	Bad Debts Allowance - Cash Basis	BADDEBT	3,554	73	1,723	523	26	1,018	192	0	0
SCHMAT	320270	Reg Asset FAS 158 Pension Liab Adj	SO	18,426	406	5,007	1,415	2,422	8,096	1,077	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	1,006	284	487	1,627	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	256	4,536	1,335	2,793	8,006	1,162	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	816	240	502	1,440	209	1	0
SCHMAT	505400	Bonus Liability	SO	(643)	(14)	(175)	(49)	(85)	(282)	(38)	(0)	0
SCHMAT	505450	Accrued Payroll Taxes	SO	16,954	374	4,607	1,301	2,229	7,449	990	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	10	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	209	61	128	368	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	77	267	34	0	0
SCHMAT	910245	Contra Receivable from Joint Owners	SO	(744)	(16)	(202)	(57)	(98)	(327)	(43)	(0)	0
SCHMAT	910905	Bridger Coal Company Underground Mine Co	SE	1,250	18	313	92	193	553	80	0	0
SCHMAT	920110	PMIWY Extraction Tax	SE	(303)	(4)	(76)	(22)	(47)	(134)	(19)	(0)	0
SCHMAT Total				**1,257,858**	**23,193**	**405,264**	**78,957**	**133,710**	**704,859**	**77,225**	**206**	**(165,556)**
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	7	0	0
SCHMDP	910900	PMIDepletion	SE	6,401	90	1,605	472	988	2,832	411	2	0
SCHMDP Total				**6,520**	**93**	**1,635**	**481**	**1,004**	**2,887**	**418**	**2**	**0**
SCHMDT	105122	Repair Deduction	SG	154,035	2,260	40,157	12,075	21,863	68,384	9,251	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	816	240	503	1,441	209	1	0
SCHMDT	105137	Capitalized Depreciation	SO	7,807	172	2,121	599	1,026	3,430	456	2	0
SCHMDT	1051411	AFUDC - DEBT	SNP	38,222	796	9,784	2,850	5,025	17,491	2,263	8	4
SCHMDT	1051412	AFUDC - Equity	SNP	78,974	1,645	20,216	5,889	10,383	36,139	4,676	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	2,636	32,480	9,176	15,715	52,517	6,983	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	1,733	21,359	6,034	10,334	34,535	4,592	16	0
SCHMDT	1052203	Cholla SHL-NOPA (Lease Amortization)	SG	2,076	30	541	163	295	922	125	1	0
SCHMDT	105470	Book Gain/Loss on Land Sales	GPS	2,100	46	571	161	276	923	123	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)	(83)	(1,465)	(431)	(902)	(2,586)	(375)	(2)	0
SCHMDT	205200	Coal M&S Inventory Write-Off	SNPD	1,063	38	281	68	102	517	56	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
SCHMDT	205205	Inventory Reserve - PMI	SE	(984)	(14)	(247)	(73)	(152)	(435)	(63)	(0)	0
SCHMDT	205411	PMISEC 263A Adjustment	SE	775	11	194	57	120	343	50	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)	(73)	(227)	(31)	(0)	0
SCHMDT	210175	Prepaid - FSA O&M - East	SG	960	14	250	75	136	426	58	0	0
SCHMDT	210180	OTHER PREPAIDS	SO	1,615	36	439	124	212	710	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	535	6,591	1,862	3,189	10,657	1,417	5	0
SCHMDT	415410	Reg Asset - Energy West Mining	SE	3,264	46	818	241	504	1,444	210	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	2,541	31,317	8,847	15,152	50,636	6,733	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)	(419)	(126)	(228)	(713)	(97)	(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

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
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)	(10)	(169)	(50)	(104)	(299)	(43)	(0)	0
SCHMDT	6101001	AMORT NOPAS 99-00 RAR	SO	28	1	8	2	4	12	2	0	0
SCHMDT	610111	Bridger Coal Company Gain/Loss on Assets	SE	(37)	(1)	(9)	(3)	(6)	(16)	(2)	(0)	0
SCHMDT	610114	PMI EITF Pre Stripping Costs	SE	(893)	(13)	(224)	(66)	(138)	(395)	(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)	(350)	(99)	(169)	(565)	(75)	(0)	0
SCHMDT	720500	Severance Accrual	SO	(2,802)	(62)	(762)	(215)	(368)	(1,231)	(164)	(1)	0
SCHMDT	720800	FAS 158 Pension Liability	SO	24,712	545	6,715	1,897	3,249	10,857	1,444	5	0
SCHMDT	720810	FAS 158 Post-Retirement Liability	SO	3,180	70	864	244	418	1,397	186	1	0
SCHMDT	720815	FAS 158 Post Retirement Liability	SO	(1,430)	(32)	(389)	(110)	(188)	(628)	(84)	(0)	0
SCHMDT	910530	Injuries and Damages Reserve	SO	(251,916)	(5,555)	(68,453)	(19,339)	(33,119)	(110,680)	(14,718)	(52)	0
SCHMDT Total				**1,617,837**	**30,252**	**427,137**	**85,497**	**210,734**	**704,087**	**100,198**	**385**	**21,187**
Grand Total				**2,885,795**	**53,616**	**835,001**	**165,209**	**345,917**	**1,413,397**	**178,050**	**594**	**(144,348)**

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	556	9,873	2,969	5,375	16,813	2,275	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	201	59	124	354	51	0	-
4101000	105137	Capitalized Depreciation	SO	1,920	42	522	147	252	843	112	0	-
4101000	105141	AFUDC Debt	SNP	9,398	196	2,406	701	1,236	4,300	556	2	1
4101000	1051411	AFUDC Equity	SNP	19,417	404	4,970	1,448	2,553	8,885	1,150	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	648	7,986	2,256	3,864	12,912	1,717	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	5,251	1,484	2,541	8,491	1,129	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)	(360)	(106)	(222)	(636)	(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)	(61)	(18)	(37)	(107)	(16)	(0)	-
4101000	205411	190PMISec263A	SE	190	3	48	14	29	84	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	62	19	34	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	132	1,621	458	784	2,620	348	1	-
4101000	415410	Reg Asset - Energy West Mining	SE	803	11	201	59	124	355	52	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	-	-	-	-	-

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	415815	Insurance Reserve	SO	28,336	625	7,700	2,175	3,725	12,450	1,655	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)	(175)	(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)	(42)	(12)	(26)	(73)	(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)	(97)	(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)	(42)	(139)	(18)	(0)	-
4101000	720500	190Severance	SO	(689)	(15)	(187)	(53)	(91)	(303)	(40)	(0)	-
4101000	720800	190FAS 158 Pension Liability	SO	6,076	134	1,651	466	799	2,669	355	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)	(96)	(27)	(46)	(154)	(21)	(0)	-
4101000	910530	190Injuries & Damages	SO	(61,938)	(1,366)	(16,830)	(4,755)	(8,143)	(27,213)	(3,619)	(13)	-
4101000 Total				**397,771**	**7,438**	**105,018**	**21,021**	**51,812**	**173,111**	**24,635**	**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)	(132)	(440)	(59)	(0)	-

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
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)	(3,753)	(47,880)	(14,097)	(24,650)	(80,251)	(10,687)	(42)	(30,051)
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)	(978)	(288)	(602)	(1,726)	(251)	(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)	(372)	(4,569)	(1,331)	(2,347)	(8,168)	(1,057)	(4)	(2)
4111000	105146	Capitalization of Test Energy	SG	(655)	(10)	(171)	(51)	(93)	(291)	(39)	(0)	-
4111000	105220	282CHOLLA TAX LEASE	SG	(1,109)	(16)	(289)	(87)	(157)	(492)	(67)	(0)	-
4111000	210200	283Prepaid Taxes-Property Taxes	GPS	1,212	27	329	93	159	533	71	0	-
4111000	220100	190Bad Debt Allowance	BADDEBT	(874)	(18)	(424)	(129)	(6)	(250)	(47)	-	-
4111000	320270	Reg Asset FAS 158 Pension Liab	SO	(4,530)	(100)	(1,231)	(348)	(596)	(1,990)	(265)	(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)	(120)	(400)	(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)	(63)	(1,115)	(328)	(687)	(1,968)	(286)	(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)	-	-

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
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)	(201)	(59)	(123)	(354)	(51)	(0)	-
4111000	505400	190Bonus Liability	SO	158	3	43	12	21	69	9	0	-
4111000	505450	Accrued Payroll Taxes	SO	(4,168)	(92)	(1,133)	(320)	(548)	(1,831)	(244)	(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)	(32)	(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

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
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	80	11	0	-
4111000	910905	283PMI BCC Underground Mine Cost Deplet	SE	(307)	(4)	(77)	(23)	(47)	(136)	(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)**	**(9,179)**	**(126,631)**	**(23,916)**	**(51,389)**	**(257,671)**	**(36,169)**	**(239)**	**42,523**
Grand Total				**(64,901)**	**(1,741)**	**(21,613)**	**(2,896)**	**423**	**(84,560)**	**(11,534)**	**(144)**	**47,732**

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	Utah	Idaho	FERC	Other
4114000	DEF ITC-EL-FED-CR	0	DEF ITC CREDIT FED	DGU	(1,703)	-	-	-	(78)	(1,431)	(194)	(1)	-
4114000 Total					**(1,703)**	**-**	**-**	**-**	**(78)**	**(1,431)**	**(194)**	**(1)**	**-**
Grand Total					**(1,703)**	**-**	**-**	**-**	**(78)**	**(1,431)**	**(194)**	**(1)**	**-**

B8. PLANT IN SERVICE

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	3,431	1,032	1,868	5,842	790	4	-
1010000	ELEC PLANT IN SERV	3020000	FRANCHISES AND CONSENTS	SG-P	177,567	2,605	46,292	13,919	25,203	78,831	10,664	52	-
1010000	ELEC PLANT IN SERV	3020000	FRANCHISES AND CONSENTS	SG-U	10,492	154	2,735	823	1,489	4,658	630	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	741	13,161	3,957	7,165	22,411	3,032	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	3,057	864	1,479	4,942	657	2	-
1010000	ELEC PLANT IN SERV	3031080	FUEL MANAGEMENT SYSTEM	SO	3,293	73	895	253	433	1,447	192	1	-
1010000	ELEC PLANT IN SERV	3031230	AUTOMATE POLE CARD SYSTEM	SO	4,410	97	1,198	339	580	1,937	258	1	-
1010000	ELEC PLANT IN SERV	3031680	DISTRIBUTION AUTOMATION PILOT PROJECT	SO	13,886	306	3,773	1,066	1,826	6,101	811	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	4,030	49,657	14,028	24,025	80,288	10,676	38	-
1010000	ELEC PLANT IN SERV	3032130	PROD & TRANS PLANT	SG	2,705	40	705	212	384	1,201	162	1	-
1010000	ELEC PLANT IN SERV	3032140	MINING PLANT	SO	1,881	41	511	144	247	827	110	0	-
1010000	ELEC PLANT IN SERV	3032150	HYDRO PLANT	SO	5,048	111	1,372	387	664	2,218	295	1	-
1010000	ELEC PLANT IN SERV	3032220	ENTERPRISE DATA WRHSE - BI RPTG TOOL	SO	1,660	37	451	127	218	729	97	0	-
1010000	ELEC PLANT IN SERV	3032270	ENTERPRISE DATA WAREHOUSE	SO	5,877	130	1,597	451	773	2,582	343	1	-
1010000	ELEC PLANT IN SERV	3032330	FIELDNET PRO METER READING SYST -HRP REP	SO	2,908	64	790	223	382	1,278	170	1	-
1010000	ELEC PLANT IN SERV	3032340	FACILITY INSPECTION REPORTING SYSTEM	SO	2,020	45	549	155	266	888	118	0	-
1010000	ELEC PLANT IN SERV	3032360	2002 GRID NET POWER COST MODELING	SO	8,960	198	2,435	688	1,178	3,936	523	2	-
1010000	ELEC PLANT IN SERV	3032450	MID OFFICE IMPROVEMENT PROJECT	SO	10,561	233	2,870	811	1,388	4,640	617	2	-
1010000	ELEC PLANT IN SERV	3032510	OPERATIONS MAPPING SYSTEM	SO	10,386	229	2,822	797	1,365	4,563	607	2	-
1010000	ELEC PLANT IN SERV	3032530	POLE ATTACHMENT MGMT SYSTEM	SO	1,892	42	514	145	249	831	111	0	-
1010000	ELEC PLANT IN SERV	3032590	SUBSTATION/CIRCUIT HISTORY OF OPERATIONS	SO	2,416	53	656	185	318	1,061	141	0	-
1010000	ELEC PLANT IN SERV	3032600	SINGLE PERSON SCHEDULING	SO	13,242	292	3,598	1,017	1,741	5,818	774	3	-
1010000	ELEC PLANT IN SERV	3032640	TIBCO SOFTWARE	SO	6,474	143	1,759	497	851	2,845	378	1	-
1010000	ELEC PLANT IN SERV	3032680	TRANSMISSION WHOLESALE BILLING SYSTEM	SG	1,600	23	417	125	227	710	96	0	-
1010000	ELEC PLANT IN SERV	3032690	UTILITY INTERNATIONAL FORECASTING MODEL	SO	6,597	145	1,793	506	867	2,898	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	6,048	1,819	3,293	10,300	1,393	7	-
1010000	ELEC PLANT IN SERV	3032770	NORTH UMPQUA - SETTLEMENT AGREEMENT	SG	652	10	170	51	93	290	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	714	202	346	1,155	154	1	-
1010000	ELEC PLANT IN SERV	3032860	WEB SOFTWARE	SO	12,006	265	3,263	922	1,578	5,275	701	2	-
1010000	ELEC PLANT IN SERV	3032900	IDAHO TRANSMISSION CUSTOMER-OWNED ASSETS	SG	8,774	129	2,287	688	1,245	3,895	527	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	1,906	538	922	3,082	410	1	-
1010000	ELEC PLANT IN SERV	3033090	STEAM PLANT INTANGIBLE ASSETS	SG	88,742	1,302	23,135	6,956	12,595	39,397	5,330	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	1,081	305	523	1,748	232	1	-
1010000	ELEC PLANT IN SERV	3033220	MONARCH EMS/SCADA	SO	29,411	649	7,992	2,258	3,867	12,922	1,718	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	82	1,005	284	486	1,625	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	745	210	360	1,204	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	5,795	1,637	2,804	9,370	1,246	4	-
1010000	ELEC PLANT IN SERV	3033320	CAS - CONTROL AREA SCHEDULING (TRANSM)	SG	10,106	148	2,635	792	1,434	4,486	607	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	417	126	227	711	96	0	-
1010000	ELEC PLANT IN SERV	3033390	RMT TRADE SYSTEM	SO	923	20	251	71	121	406	54	0	-
1010000	ELEC PLANT IN SERV	3033410	M365	SO	3,700	82	1,005	284	486	1,626	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	-	-

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	111	1,966	591	1,071	3,348	453	2	-
1010000	ELEC PLANT IN SERV	3034900	MISC - MISCELLANEOUS	SO	47,842	1,055	13,000	3,673	6,290	21,020	2,795	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	455	137	248	775	105	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	337	95	163	545	72	0	-
1010000	ELEC PLANT IN SERV	3100000	LAND & LAND RIGHTS	SG	1,306	19	341	102	185	580	78	0	-
1010000	ELEC PLANT IN SERV	3101000	LAND OWNED IN FEE	SG	12,850	189	3,350	1,007	1,824	5,705	772	4	-
1010000	ELEC PLANT IN SERV	3102000	LAND RIGHTS	SG	41,789	613	10,895	3,276	5,931	18,552	2,510	12	-
1010000	ELEC PLANT IN SERV	3103000	WATER RIGHTS	SG	35,638	523	9,291	2,794	5,058	15,821	2,140	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	14,641	260,133	78,218	141,623	442,978	59,928	292	-
1010000	ELEC PLANT IN SERV	3120000	BOILER PLANT EQUIPMENT	SG	4,337,203	63,640	1,130,724	339,991	615,593	1,925,498	260,488	1,269	-
1010000	ELEC PLANT IN SERV	3140000	TURBOGENERATOR UNITS	SG	945,572	13,874	246,514	74,123	134,208	419,786	56,790	277	-
1010000	ELEC PLANT IN SERV	3150000	ACCESSORY ELECTRIC EQUIPMENT	SG	423,546	6,215	110,420	33,202	60,115	188,033	25,438	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	455	8,081	2,430	4,400	13,762	1,862	9	-
1010000	ELEC PLANT IN SERV	3300000	LAND AND LAND RIGHTS	SG-U	172	3	45	13	24	76	10	0	-
1010000	ELEC PLANT IN SERV	3301000	LAND OWNED IN FEE	SG-P	23,525	345	6,133	1,844	3,339	10,444	1,413	7	-
1010000	ELEC PLANT IN SERV	3301000	LAND OWNED IN FEE	SG-U	5,780	85	1,507	453	820	2,566	347	2	-
1010000	ELEC PLANT IN SERV	3302000	LAND RIGHTS	SG-P	8,035	118	2,095	630	1,140	3,567	483	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	81	24	44	137	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	2,040	613	1,111	3,474	470	2	-
1010000	ELEC PLANT IN SERV	3311000	STRUCTURES AND IMPROVE-PRODUCTION	SG-P	71,873	1,055	18,738	5,634	10,201	31,908	4,317	21	-
1010000	ELEC PLANT IN SERV	3311000	STRUCTURES AND IMPROVE-PRODUCTION	SG-U	8,962	131	2,336	703	1,272	3,979	538	3	-
1010000	ELEC PLANT IN SERV	3312000	STRUCTURES AND IMPROVE-FISH/WILDLIFE	SG-P	159,638	2,342	41,618	12,514	22,658	70,871	9,588	47	-
1010000	ELEC PLANT IN SERV	3312000	STRUCTURES AND IMPROVE-FISH/WILDLIFE	SG-U	364	5	95	29	52	161	22	0	-
1010000	ELEC PLANT IN SERV	3313000	STRUCTURES AND IMPROVE-RECREATION	SG-P	22,814	335	5,948	1,788	3,238	10,128	1,370	7	-
1010000	ELEC PLANT IN SERV	3313000	STRUCTURES AND IMPROVE-RECREATION	SG-U	2,031	30	530	159	288	902	122	1	-
1010000	ELEC PLANT IN SERV	3316000	STRUCTURES - LEASE IMPROVEMENTS	SG-P	14,659	215	3,822	1,149	2,081	6,508	880	4	-
1010000	ELEC PLANT IN SERV	3320000	"RESERVOIRS, DAMS & WATERWAYS"	SG-P	6,552	96	1,708	514	930	2,909	394	2	-
1010000	ELEC PLANT IN SERV	3320000	"RESERVOIRS, DAMS & WATERWAYS"	SG-U	27,538	404	7,179	2,159	3,909	12,226	1,654	8	-
1010000	ELEC PLANT IN SERV	3321000	"RESERVOIRS, DAMS, & WTRWYS-PRODUCTION"	SG-P	402,952	5,912	105,051	31,587	57,192	178,890	24,201	118	-
1010000	ELEC PLANT IN SERV	3321000	"RESERVOIRS, DAMS, & WTRWYS-PRODUCTION"	SG-U	70,893	1,040	18,482	5,557	10,062	31,473	4,258	21	-
1010000	ELEC PLANT IN SERV	3322000	"RESERVOIRS, DAMS, & WTRWYS-FISH/WILDLIF	SG-P	23,797	349	6,204	1,865	3,378	10,565	1,429	7	-
1010000	ELEC PLANT IN SERV	3322000	"RESERVOIRS, DAMS, & WTRWYS-FISH/WILDLIF	SG-U	411	6	107	32	58	182	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	1,407	25,007	7,519	13,615	42,585	5,761	28	-
1010000	ELEC PLANT IN SERV	3330000	"WATER WHEELS, TURB & GENERATORS"	SG-U	50,316	738	13,118	3,944	7,141	22,338	3,022	15	-
1010000	ELEC PLANT IN SERV	3340000	ACCESSORY ELECTRIC EQUIPMENT	SG-P	68,603	1,007	17,885	5,378	9,737	30,456	4,120	20	-
1010000	ELEC PLANT IN SERV	3340000	ACCESSORY ELECTRIC EQUIPMENT	SG-U	14,470	212	3,772	1,134	2,054	6,424	869	4	-
1010000	ELEC PLANT IN SERV	3347000	ACCESSORY ELECT EQUIP - SUPV & ALARM	SG-P	2,896	42	755	227	411	1,285	174	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	14	24	76	10	0	-
1010000	ELEC PLANT IN SERV	3351000	MISC POWER PLANT EQUIP - PRODUCTION	SG-P	2,392	35	624	187	339	1,062	144	1	-
1010000	ELEC PLANT IN SERV	3360000	"ROADS, RAILROADS & BRIDGES"	SG-P	23,207	341	6,050	1,819	3,294	10,303	1,394	7	-
1010000	ELEC PLANT IN SERV	3360000	"ROADS, RAILROADS & BRIDGES"	SG-U	3,068	45	800	240	435	1,362	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	186	3,297	991	1,795	5,615	760	4	-
1010000	ELEC PLANT IN SERV	3402000	LAND RIGHTS	SG	5,680	83	1,481	445	806	2,521	341	2	-
1010000	ELEC PLANT IN SERV	3403000	WATER RIGHTS - OTHER PRODUCTION	SG	32,709	480	8,527	2,564	4,643	14,521	1,964	10	-
1010000	ELEC PLANT IN SERV	3410000	STRUCTURES & IMPROVEMENTS	SG	270,178	3,964	70,436	21,179	38,347	119,945	16,227	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	4,271	1,284	2,325	7,273	984	5	-

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	3430000	PRIME MOVERS	SG	3,969,484	58,244	1,034,858	311,166	563,402	1,762,250	238,403	1,162	-
1010000	ELEC PLANT IN SERV	3440000	GENERATORS	SG	586,547	8,606	152,915	45,979	83,250	260,397	35,227	172	-
1010000	ELEC PLANT IN SERV	3440000	GENERATORS	UT	235	-	-	-	-	235	-	-	-
1010000	ELEC PLANT IN SERV	3450000	ACCESSORY ELECTRIC EQUIPMENT	SG	451,136	6,620	117,613	35,364	64,031	200,282	27,095	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	346	6,144	1,848	3,345	10,463	1,416	7	-
1010000	ELEC PLANT IN SERV	3500000	LAND AND LAND RIGHTS	SG	841	12	219	66	119	373	51	0	-
1010000	ELEC PLANT IN SERV	3501000	LAND OWNED IN FEE	SG	62,585	918	16,316	4,906	8,883	27,784	3,759	18	-
1010000	ELEC PLANT IN SERV	3502000	LAND RIGHTS	SG	246,449	3,616	64,250	19,319	34,979	109,411	14,801	72	-
1010000	ELEC PLANT IN SERV	3520000	STRUCTURES & IMPROVEMENTS	SG	313,031	4,593	81,608	24,538	44,430	138,970	18,800	92	-
1010000	ELEC PLANT IN SERV	3530000	STATION EQUIPMENT	SG	2,151,514	31,569	560,907	168,656	305,371	955,163	129,218	630	-
1010000	ELEC PLANT IN SERV	3534000	STATION EQUIPMENT, STEP-UP TRANSFORMERS	SG	166,982	2,450	43,533	13,090	23,700	74,131	10,029	49	-
1010000	ELEC PLANT IN SERV	3537000	STATION EQUIPMENT-SUPERVISORY & ALARM	SG	23,178	340	6,043	1,817	3,290	10,290	1,392	7	-
1010000	ELEC PLANT IN SERV	3540000	TOWERS AND FIXTURES	SG	1,333,441	19,566	347,633	104,528	189,260	591,980	80,085	390	-
1010000	ELEC PLANT IN SERV	3550000	POLES AND FIXTURES	SG	1,109,258	16,276	289,187	86,954	157,441	492,454	66,621	325	-
1010000	ELEC PLANT IN SERV	3560000	OVERHEAD CONDUCTORS & DEVICES	SG	1,379,079	20,235	359,531	108,105	195,737	612,241	82,826	404	-
1010000	ELEC PLANT IN SERV	3570000	UNDERGROUND CONDUIT	SG	3,858	57	1,006	302	548	1,713	232	1	-
1010000	ELEC PLANT IN SERV	3580000	UNDERGROUND CONDUCTORS & DEVICES	SG	9,081	133	2,367	712	1,289	4,031	545	3	-
1010000	ELEC PLANT IN SERV	3590000	ROADS AND TRAILS	SG	12,146	178	3,167	952	1,724	5,392	729	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	-	-	-	-

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	-	-	-

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	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	2,042	577	988	3,302	439	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	13	223	66	137	393	57	0	-
1010000	ELEC PLANT IN SERV	3900000	STRUCTURES AND IMPROVEMENTS	SG	12,084	177	3,150	947	1,715	5,365	726	4	-
1010000	ELEC PLANT IN SERV	3900000	STRUCTURES AND IMPROVEMENTS	SO	99,576	2,196	27,058	7,644	13,091	43,749	5,817	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	493	139	239	798	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	426	128	232	725	98	0	-
1010000	ELEC PLANT IN SERV	3910000	OFFICE FURNITURE	SO	13,207	291	3,589	1,014	1,736	5,802	772	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	12	2	0	-
1010000	ELEC PLANT IN SERV	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	SG	2,446	36	638	192	347	1,086	147	1	-
1010000	ELEC PLANT IN SERV	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	SO	47,440	1,046	12,891	3,642	6,237	20,843	2,772	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	-	-

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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	235	32	0	-
1010000	ELEC PLANT IN SERV	3920100	1/4 TON MINI-PICKUPS AND VANS	SO	1,212	27	329	93	159	532	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	84	24	40	135	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	2,278	685	1,240	3,879	525	3	-
1010000	ELEC PLANT IN SERV	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	SO	1,363	30	370	105	179	599	80	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	80	12	0	-
1010000	ELEC PLANT IN SERV	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	SG	7,477	110	1,949	586	1,061	3,320	449	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	977	294	532	1,663	225	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	447	134	243	761	103	1	-
1010000	ELEC PLANT IN SERV	3920900	TRAILERS	SO	1,272	28	346	98	167	559	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	361	109	197	615	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	203	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	813	230	394	1,315	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	-	-	-	-	-	-

PACIFICORP

Electric Plant in Service (Actuals)
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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	1,580	475	860	2,691	364	2	-
1010000	ELEC PLANT IN SERV	3930000	STORES EQUIPMENT	SO	249	5	68	19	33	109	15	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	32	9	19	56	8	0	-
1010000	ELEC PLANT IN SERV	3940000	"TLS, SHOP, GAR EQUIPMENT"	SG	21,817	320	5,688	1,710	3,097	9,686	1,310	6	-
1010000	ELEC PLANT IN SERV	3940000	"TLS, SHOP, GAR EQUIPMENT"	SO	1,960	43	533	150	258	861	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	337	99	207	594	86	0	-
1010000	ELEC PLANT IN SERV	3950000	LABORATORY EQUIPMENT	SG	6,462	95	1,685	507	917	2,869	388	2	-
1010000	ELEC PLANT IN SERV	3950000	LABORATORY EQUIPMENT	SO	4,873	107	1,324	374	641	2,141	285	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	172	23	0	-
1010000	ELEC PLANT IN SERV	3960300	"AERIAL LIFT PB TRUCKS, 10000#-16000# GV	SO	3,234	71	879	248	425	1,421	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	321	97	175	547	74	0	-
1010000	ELEC PLANT IN SERV	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	SO	1,566	35	426	120	206	688	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	789	237	429	1,343	182	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	504	8,955	2,693	4,875	15,249	2,063	10	-
1010000	ELEC PLANT IN SERV	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	SO	1,321	29	359	101	174	581	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	26	46	144	20	0	-
1010000	ELEC PLANT IN SERV	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	SO	1,274	28	346	98	167	560	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	37	105	15	0	-
1010000	ELEC PLANT IN SERV	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	SG	6,906	101	1,800	541	980	3,066	415	2	-
1010000	ELEC PLANT IN SERV	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	SO	941	21	256	72	124	413	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	124	18	0	-
1010000	ELEC PLANT IN SERV	3970000	COMMUNICATION EQUIPMENT	SG	178,602	2,621	46,562	14,001	25,350	79,290	10,727	52	-
1010000	ELEC PLANT IN SERV	3970000	COMMUNICATION EQUIPMENT	SO	93,553	2,063	25,421	7,182	12,299	41,103	5,466	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	21	6	13	36	5	0	-
1010000	ELEC PLANT IN SERV	3972000	MOBILE RADIO EQUIPMENT	SG	4,050	59	1,056	317	575	1,798	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	749	225	408	1,275	172	1	-
1010000	ELEC PLANT IN SERV	3980000	MISCELLANEOUS EQUIPMENT	SO	2,229	49	606	171	293	979	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	457	134	281	807	117	1	-
1010000 Total					**30,113,118**	**645,523**	**8,255,450**	**2,316,784**	**3,985,469**	**13,156,757**	**1,746,889**	**6,246**	**-**
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)	(339)	(96)	(164)	(548)	(73)	(0)	-
1019000	ELEC PLT IN SERV-OTH	140139	PRODUCTION PLANT-NON-RECONCILED	SG	(19,189)	(282)	(5,003)	(1,504)	(2,723)	(8,519)	(1,152)	(6)	-
1019000	ELEC PLT IN SERV-OTH	140149	TRANS PLANT NON-RECONCILED	SG	(5,037)	(74)	(1,313)	(395)	(715)	(2,236)	(303)	(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)**	**(768)**	**(8,794)**	**(2,541)**	**(4,403)**	**(13,516)**	**(1,836)**	**(7)**	**-**
1020000	ELEC PL PUR OR SLD	0	ELECTRIC PLANT PURCHASED OR SOLD	SG	(553)	(8)	(144)	(43)	(79)	(246)	(33)	(0)	-
1020000	ELEC PL PUR OR SLD	140708	CONTRA ELEC PLANT PURCH OR SOLD - LOSS	SG	553	8	144	43	79	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	13,644	242,427	72,894	131,983	412,827	55,849	272	-
1062000 Total					**929,896**	**13,644**	**242,427**	**72,894**	**131,983**	**412,827**	**55,849**	**272**	**-**
1063000	PROD COMP CONST NOT	0	PROD COMPLETED CONSTRUCTN NOT CLASSIFIED	SG	75,860	1,113	19,777	5,947	10,767	33,678	4,556	22	-
1063000 Total					**75,860**	**1,113**	**19,777**	**5,947**	**10,767**	**33,678**	**4,556**	**22**	**-**
1064000	GEN COMP CONST NOT	0	GENERAL COMPLETED CONSTRUCTN NOT CLASSIF	SO	62,878	1,387	17,086	4,827	8,267	27,626	3,673	13	-
1064000 Total					**62,878**	**1,387**	**17,086**	**4,827**	**8,267**	**27,626**	**3,673**	**13**	**-**
Grand Total					**31,317,729**	**665,844**	**8,567,379**	**2,408,573**	**4,153,174**	**13,696,568**	**1,819,644**	**6,546**	**-**

B9. CAPITAL LEASE PLANT

PACIFICORP

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	627	177	303	1,013	135	0	-
1011000	PRPTY UND CPTL LSS	3908230	(FINANCE LEASES-GAS)	SG	12,159	178	3,170	953	1,726	5,398	730	4	-
1011000 Total					**17,180**	**229**	**6,511**	**1,130**	**2,029**	**6,411**	**865**	**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)	(627)	(177)	(303)	(1,013)	(135)	(0)	-
1011500	CAP LEASES–ACCM AMRT	3908230	(FINANCE LEASES-GAS)	SG	(2,278)	(33)	(594)	(179)	(323)	(1,011)	(137)	(1)	-
1011500 Total					**(5,686)**	**(84)**	**(2,322)**	**(356)**	**(627)**	**(2,025)**	**(272)**	**(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	1,249	376	680	2,128	288	1	-
1011900 Total					**19,653**	**70**	**4,395**	**376**	**680**	**13,842**	**288**	**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)	(1,249)	(376)	(680)	(2,128)	(288)	(1)	-
1011950 Total					**(17,097)**	**(70)**	**(4,395)**	**(376)**	**(680)**	**(11,286)**	**(288)**	**(1)**	**-**
Grand Total					**14,049**	**145**	**4,189**	**775**	**1,402**	**6,942**	**593**	**3**	**-**

B10.PLANT HELD FOR FUTURE USE

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	2,326	699	1,267	3,961	536	3	-
1050000	EL PLT HLD FTR USE	3501000	LAND OWNED IN FEE	SG	925	14	241	73	131	411	56	0	-
1050000	EL PLT HLD FTR USE	3502000	LAND RIGHTS	SG	755	11	197	59	107	335	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**	**839**	**9,658**	**831**	**1,506**	**10,423**	**637**	**3**	**-**
Grand Total					**23,896**	**839**	**9,658**	**831**	**1,506**	**10,423**	**637**	**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	588	173	362	1,038	151	1	-
1861000	MS DEF DB-OTH WIP	185017	ERCs - Impairment Reserve	SE	(2,040)	(29)	(511)	(151)	(315)	(903)	(131)	(1)	-
1861000 Total					**307**	**4**	**77**	**23**	**47**	**136**	**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**	**34**	**5**	**0**	**2,335**
1865000	DEF COAL MINE COSTS	184414	DEFERRED COAL COSTS - WYODAK SETTLEMENT	SE	503	7	126	37	78	222	32	0	-
1865000 Total					**503**	**7**	**126**	**37**	**78**	**222**	**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	1,013	305	552	1,726	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	200	60	109	341	46	0	-
1868000	MISC DF DR-OTH-CST	185337	POINT-TO-POINT TRANS RESERVATIONS	SG	1,892	28	493	148	268	840	114	1	-
1868000	MISC DF DR-OTH-CST	185359	LT Lake Side 2 Maint. Prepayment	SG	21,225	311	5,533	1,664	3,013	9,423	1,275	6	-
1868000	MISC DF DR-OTH-CST	185360	LT LAKE SIDE MAINT PREPAYMENT	SG	11,807	173	3,078	926	1,676	5,242	709	3	-
1868000	MISC DF DR-OTH-CST	185361	LT CHEHALIS CSA MAINT. PREPAYMENT	SG	23,923	351	6,237	1,875	3,395	10,621	1,437	7	-
1868000	MISC DF DR-OTH-CST	185362	LT Currant Creek CSA Maint Prepayment	SG	23,241	341	6,059	1,822	3,299	10,318	1,396	7	-
1868000	MISC DF DR-OTH-CST	185371	LT Chehalis CSA Prepaid O&M	SG	1,114	16	291	87	158	495	67	0	-
1868000	MISC DF DR-OTH-CST	185551	LT Prepaid-FSA Capital - Dunlap	SG	1,525	22	397	120	216	677	92	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	709	213	386	1,207	163	1	-
1868000	MISC DF DR-OTH-CST	185558	LT Prepaid-FSA Capital - Glenrock III	SG	1,071	16	279	84	152	476	64	0	-
1868000	MISC DF DR-OTH-CST	185561	LT Prepaid-FSA Capital - Goodnoe Hills	SG	1,920	28	501	151	273	852	115	1	-
1868000	MISC DF DR-OTH-CST	185564	LT Prepaid-FSA Capital - High Plains	SG	2,720	40	709	213	386	1,207	163	1	-
1868000	MISC DF DR-OTH-CST	185567	LT Prepaid-FSA Capital - Leaning Juniper	SG	2,761	41	720	216	392	1,226	166	1	-
1868000	MISC DF DR-OTH-CST	185570	LT Prepaid-FSA Capital - Marengo I	SG	2,243	33	585	176	318	996	135	1	-
1868000	MISC DF DR-OTH-CST	185571	LT Prepaid-FSA Capital - Marengo II	SG	1,111	16	290	87	158	493	67	0	-
1868000	MISC DF DR-OTH-CST	185574	LT Prepaid-FSA Capital - McFadden Ridge	SG	783	11	204	61	111	348	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	709	213	386	1,207	163	1	-
1868000	MISC DF DR-OTH-CST	185580	LT Prepaid-FSA Capital - Seven Mile I	SG	2,720	40	709	213	386	1,207	163	1	-
1868000	MISC DF DR-OTH-CST	185581	LT Prepaid-FSA Capital - Seven Mile II	SG	536	8	140	42	76	238	32	0	-
1868000 Total					**110,978**	**1,627**	**28,904**	**8,691**	**15,736**	**49,221**	**6,659**	**32**	**108**
1869000	MISC DF DR-OTH-NC	185334	HERMISTON SWAP	SG	2,590	38	675	203	368	1,150	156	1	-
1869000 Total					**2,590**	**38**	**675**	**203**	**368**	**1,150**	**156**	**1**	**-**
Grand Total					**116,791**	**1,678**	**29,804**	**8,960**	**16,239**	**50,763**	**6,871**	**33**	**2,444**

B13. MATERIALS & SUPPLIES

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
1511120	COAL INVNTRY-HUNTER	0	COAL INVENTORY - HUNTER	SE	71,160	1,006	17,839	5,250	10,983	31,487	4,571	24	-
1511120 Total					**71,160**	**1,006**	**17,839**	**5,250**	**10,983**	**31,487**	**4,571**	**24**	**-**
1511130	COAL INVNTRY-HTG	0	COAL INVENTORY - HUNTINGTON	SE	23,857	337	5,980	1,760	3,682	10,556	1,533	8	-
1511130 Total					**23,857**	**337**	**5,980**	**1,760**	**3,682**	**10,556**	**1,533**	**8**	**-**
1511140	COAL INVNTRY-JB	0	COAL INVENTORY - JIM BRIDGER	SE	34,164	483	8,564	2,521	5,273	15,117	2,195	12	-
1511140 Total					**34,164**	**483**	**8,564**	**2,521**	**5,273**	**15,117**	**2,195**	**12**	**-**
1511160	COAL INVNTRY-NAU	0	COAL INVENTORY - NAUGHTON	SE	24,588	347	6,164	1,814	3,795	10,880	1,580	8	-
1511160 Total					**24,588**	**347**	**6,164**	**1,814**	**3,795**	**10,880**	**1,580**	**8**	**-**
1511300	COAL INVNTRY-COLSTRI	0	COAL INVENTORY - COLSTIP	SE	1,908	27	478	141	294	844	123	1	-
1511300 Total					**1,908**	**27**	**478**	**141**	**294**	**844**	**123**	**1**	**-**
1511400	COAL INVNTRY-CRAIG	0	COAL INVENTORY - CRAIG	SE	611	9	153	45	94	270	39	0	-
1511400 Total					**611**	**9**	**153**	**45**	**94**	**270**	**39**	**0**	**-**
1511600	COAL INVNTRY-DJ	0	COAL INVENTORY - DAVE JOHNSTON	SE	11,803	167	2,959	871	1,822	5,222	758	4	-
1511600 Total					**11,803**	**167**	**2,959**	**871**	**1,822**	**5,222**	**758**	**4**	**-**
1511700	COAL INVNTRY-RG	0	COAL INVENTORY ROCK GARDEN PILE	SE	31,430	444	7,879	2,319	4,851	13,907	2,019	11	-
1511700 Total					**31,430**	**444**	**7,879**	**2,319**	**4,851**	**13,907**	**2,019**	**11**	**-**
1511900	COAL INVNTRY-HAYDEN	0	COAL INVENTORY - HAYDEN	SE	4,236	60	1,062	313	654	1,874	272	1	-
1511900 Total					**4,236**	**60**	**1,062**	**313**	**654**	**1,874**	**272**	**1**	**-**
1512180	NATURAL GAS-CLAY BAS	0	NATURAL GAS - CLAY BASIN	SE	793	11	199	59	122	351	51	0	-
1512180 Total					**793**	**11**	**199**	**59**	**122**	**351**	**51**	**0**	**-**
1514000	FUEL STK-FUEL OIL	0	FUEL STOCK COAL MINE	SE	2,201	31	552	162	340	974	141	1	-
1514000 Total					**2,201**	**31**	**552**	**162**	**340**	**974**	**141**	**1**	**-**
1514300	OIL INVNTRY-COLSTRIP	0	OIL INVENTORY - COLSTRIP	SE	82	1	21	6	13	36	5	0	-
1514300 Total					**82**	**1**	**21**	**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	366	6,499	1,954	3,538	11,067	1,497	7	-
1541000	PLNT M&S STK CNTRL	1515	DAVE JOHNSTON STORE ROOM	SG	18,286	268	4,767	1,433	2,595	8,118	1,098	5	-
1541000	PLNT M&S STK CNTRL	1520	WYODAK STORE ROOM	SG	6,682	98	1,742	524	948	2,966	401	2	-
1541000	PLNT M&S STK CNTRL	1525	GADSBY STORE ROOM	SG	4,424	65	1,153	347	628	1,964	266	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	198	3,518	1,058	1,915	5,990	810	4	-
1541000	PLNT M&S STK CNTRL	1540	HUNTINGTON STORE ROOM	SG	18,984	279	4,949	1,488	2,694	8,428	1,140	6	-
1541000	PLNT M&S STK CNTRL	1545	HUNTER STORE ROOM	SG	26,671	391	6,953	2,091	3,786	11,841	1,602	8	-
1541000	PLNT M&S STK CNTRL	1550	BLUNDELL STORE ROOM	SG	1,084	16	283	85	154	481	65	0	-
1541000	PLNT M&S STK CNTRL	1565	CURRANT CREEK PLANT	SG	4,018	59	1,047	315	570	1,784	241	1	-
1541000	PLNT M&S STK CNTRL	1570	LAKESIDE PLANT	SG	6,502	95	1,695	510	923	2,887	391	2	-
1541000	PLNT M&S STK CNTRL	1580	CHEHALIS PLANT	SG	3,682	54	960	289	523	1,634	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	104	14	0	-
1541000	PLNT M&S STK CNTRL	1705	GOODNOE HILLS WIND	SG	129	2	34	10	18	57	8	0	-
1541000	PLNT M&S STK CNTRL	1715	MARENGO WIND	SG	367	5	96	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	15	258	78	141	440	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	118	35	64	201	27	0	-
1541000	PLNT M&S STK CNTRL	1745	Dunlap Wind Project	SG	573	8	149	45	81	254	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	-

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	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	9	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**	**4,519**	**83,599**	**21,303**	**31,754**	**118,935**	**14,668**	**39**	**-**
1541500	OTHER M&S	0	M&S GLENROCK COAL MINE	SE	198	3	50	15	30	87	13	0	-
1541500	OTHER M&S	120001	OTHER MATERIAL & SUPPLIES - GENERAL STOC	SE	(198)	(3)	(50)	(15)	(30)	(87)	(13)	(0)	-
1541500	OTHER M&S	120001	OTHER MATERIAL & SUPPLIES - GENERAL STOC	SO	137	3	37	11	18	60	8	0	-
1541500 Total					**137**	**3**	**37**	**11**	**18**	**60**	**8**	**0**	**-**
1541900	PLNT M&S GEN JV CUT	120005	JV CUTBACK MATERIAL & SUPPLIES INVENTORY	SG	2,154	32	562	169	306	956	129	1	-
1541900	PLNT M&S GEN JV CUT	120005	JV CUTBACK MATERIAL & SUPPLIES INVENTORY	SO	(1,380)	(30)	(375)	(106)	(181)	(606)	(81)	(0)	-
1541900 Total					**775**	**1**	**187**	**63**	**124**	**350**	**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)	(239)	(72)	(130)	(406)	(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)**	**(67)**	**(640)**	**(169)**	**(277)**	**(1,142)**	**(136)**	**(0)**	**-**
2531600	WORK CAP DEP-UAMPS	289920	WORKING CAPITAL DEPOSIT - UAMPS	SE	(2,806)	(40)	(703)	(207)	(433)	(1,242)	(180)	(1)	-
2531600 Total					**(2,806)**	**(40)**	**(703)**	**(207)**	**(433)**	**(1,242)**	**(180)**	**(1)**	**-**
2531700	WORKG CAP DEP-DG&T	289921	OTH DEF CR - WORKING CAPITAL DEPOS-DG&T	SE	(2,676)	(38)	(671)	(197)	(413)	(1,184)	(172)	(1)	-
2531700 Total					**(2,676)**	**(38)**	**(671)**	**(197)**	**(413)**	**(1,184)**	**(172)**	**(1)**	**-**
2531800	WCD-PROVO-PLNT M&S	289922	OTH DEF CR - WCD - PROVO - PLANT M&S	SG	(273)	(4)	(71)	(21)	(39)	(121)	(16)	(0)	-
2531800 Total					**(273)**	**(4)**	**(71)**	**(21)**	**(39)**	**(121)**	**(16)**	**(0)**	**-**
Grand Total					**474,499**	**7,300**	**133,618**	**36,051**	**62,677**	**207,230**	**27,516**	**107**	**-**

B14. CASH WORKING CAPITAL

PACIFICORP

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	1,260	356	587	2,037	271	1	-
1431000 Total					**4,636**	**102**	**1,260**	**356**	**587**	**2,037**	**271**	**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	91	12	0	-
1431500	INC TAXES RECEIVABLE	116134	InterCo State Tax Rec -(Odd Years)- MEHC	SO	(28)	(1)	(8)	(2)	(4)	(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	362	102	168	585	78	0	-
1433000 Total					**1,331**	**29**	**362**	**102**	**168**	**585**	**78**	**0**	**-**
1436000	OTH ACCT REC	0	OTHER ACCOUNTS RECEIVABLE	SO	27,753	612	7,541	2,130	3,513	12,193	1,621	6	-
1436000 Total					**27,753**	**612**	**7,541**	**2,130**	**3,513**	**12,193**	**1,621**	**6**	**-**
1437000	CSS OAR BILLINGS	0	CSS OAR BILLINGS	SO	6,836	151	1,858	525	865	3,003	399	1	-
1437000 Total					**6,836**	**151**	**1,858**	**525**	**865**	**3,003**	**399**	**1**	**-**
1437100	CSS OAR BILLINGS-WOR	0	OTHER ACCT REC CCS	SO	(2,032)	(45)	(552)	(156)	(257)	(893)	(119)	(0)	-
1437100 Total					**(2,032)**	**(45)**	**(552)**	**(156)**	**(257)**	**(893)**	**(119)**	**(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)	(466)	(137)	(273)	(823)	(119)	(1)	-
2320000	ACCOUNTS PAYABLE	210677	Bronco Utah Operations LLC - Coal	SE	(1,192)	(17)	(299)	(88)	(175)	(527)	(77)	(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)	(605)	(80)	(0)	-
2320000	ACCOUNTS PAYABLE	215080	METLIFE MEDICAL INSURANCE	SO	(3,163)	(70)	(859)	(243)	(400)	(1,390)	(185)	(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)	(868)	(261)	(448)	(1,479)	(200)	(1)	-
2320000	ACCOUNTS PAYABLE	235230	ACCRUAL - ROYALTIES	SE	(64)	(1)	(16)	(5)	(9)	(28)	(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)**	**(229)**	**(3,322)**	**(964)**	**(1,684)**	**(5,562)**	**(760)**	**(3)**	**(19)**
2533000	O DEF CR-MISC PPL	289517	TRAPPER MINE FINAL RECLAMATION	SE	(7,150)	(101)	(1,792)	(528)	(1,048)	(3,164)	(459)	(2)	-
2533000 Total					**(7,150)**	**(101)**	**(1,792)**	**(528)**	**(1,048)**	**(3,164)**	**(459)**	**(2)**	**-**
Grand Total					**15,886**	**522**	**5,384**	**1,475**	**2,159**	**8,249**	**1,038**	**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	2,123	37,725	11,343	20,538	64,242	8,691	42	-
1140000	EL PLT ACQUIST ADJ	1140000	ELECTRIC PLANT ACQUISITION ADJUSTMENTS	UT	11,764	-	-	-	-	11,764	-	-	-
1140000 Total					**156,468**	**2,123**	**37,725**	**11,343**	**20,538**	**76,005**	**8,691**	**42**	**-**
1150000	Ac Prov El Pt Acq Ad	1140000	ACCUM PROV ELECTRIC PLANT ACQUISITION AD	SG	(137,980)	(2,025)	(35,972)	(10,816)	(19,584)	(61,256)	(8,287)	(40)	-
1150000	Ac Prov El Pt Acq Ad	1140000	ACCUM PROV ELECTRIC PLANT ACQUISITION AD	UT	(1,898)	-	-	-	-	(1,898)	-	-	-
1150000 Total					**(139,878)**	**(2,025)**	**(35,972)**	**(10,816)**	**(19,584)**	**(63,154)**	**(8,287)**	**(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	632	7,787	2,200	3,767	12,591	1,674	6	-
1281000 Total					**28,657**	**632**	**7,787**	**2,200**	**3,767**	**12,591**	**1,674**	**6**	**-**
1651000	PREPAY-INSURANCE	132008	PREPAID INSURANCE - PUBLIC LIABILITY & P	SO	801	18	218	61	105	352	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	94	26	45	151	20	0	-
1651000	PREPAY-INSURANCE	132055	PREPAID EMPLOYEE BENEFIT COSTS	SO	8	0	2	1	1	4	0	0	-
1651000 Total					**2,188**	**48**	**595**	**168**	**288**	**961**	**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	30	92	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	15	26	82	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	44	79	247	33	0	-
1652100	PREPAY - OTHER	132567	Prepaid-FSA O&M - Leaning Juniper	SG	282	4	74	22	40	125	17	0	-
1652100	PREPAY - OTHER	132574	Prepaid-FSA O&M - McFadden Ridge	SG	107	2	28	8	15	47	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	73	22	39	123	17	0	-
1652100	PREPAY - OTHER	132580	Prepaid-FSA O&M - Seven Mile I	SG	185	3	48	15	26	82	11	0	-
1652100	PREPAY - OTHER	132581	Prepaid-FSA O&M - Seven Mile II	SG	37	1	10	3	5	16	2	0	-
1652100	PREPAY - OTHER	132620	PREPAYMENTS - WATER RIGHTS LEASE	SG	643	9	168	50	91	286	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	117	16	0	-
1652100	PREPAY - OTHER	132650	PREPAID DUES	SO	3,478	77	945	267	457	1,528	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	589	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	4,041	1,142	1,955	6,534	869	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)	(717)	(203)	(347)	(1,160)	(154)	(1)	-
1652100	PREPAY - OTHER	134000	L/T PREPAY RECLASS	SO	2,667	59	725	205	351	1,172	156	1	-
1652100 Total					**65,187**	**495**	**10,487**	**1,829**	**3,163**	**17,384**	**1,678**	**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)	(5,654)	(69,673)	(19,683)	(33,709)	(112,653)	(14,980)	(53)	-
2282100 Total					**(256,406)**	**(5,654)**	**(69,673)**	**(19,683)**	**(33,709)**	**(112,653)**	**(14,980)**	**(53)**	**-**
2282400	ACCUM PRV FR I&D-OR	288700	Reg Liab - OR Injuries & Damages Reserve	OR	(12,416)	-	(12,416)	-	-	-	-	-	-

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
2282400 Total					**(12,416)**	**-**	**(12,416)**	**-**	**-**	**-**	**-**	**-**	**-**
2282500	Acc Prov I&D-Insur	156909	Insurance Reim Receivable (I&D)-NonCurr	SO	115,250	2,541	31,317	8,847	15,152	50,636	6,733	24	-
2282500 Total					**115,250**	**2,541**	**31,317**	**8,847**	**15,152**	**50,636**	**6,733**	**24**	**-**
2283000	PEN/BENFT-SICK	280349	SUPPL. PENSION BENEFITS (RETIRE ALLOW)	SO	(1,612)	(36)	(438)	(124)	(212)	(708)	(94)	(0)	-
2283000 Total					**(1,612)**	**(36)**	**(438)**	**(124)**	**(212)**	**(708)**	**(94)**	**(0)**	**-**
2283400	POST-RETIREMENT BEN	280329	FAS 106-Contra Liability-Medicare Subsid	SO	22,389	494	6,084	1,719	2,943	9,837	1,308	5	-
2283400	POST-RETIREMENT BEN	280440	FAS 158 PR Liab Medicare Sub (Non-Dedct)	SO	(5,429)	(120)	(1,475)	(417)	(714)	(2,385)	(317)	(1)	-
2283400	POST-RETIREMENT BEN	280454	FAS 158 PR Liab Reg Medicare (Non-Dedct)	SO	5,429	120	1,475	417	714	2,385	317	1	-
2283400	POST-RETIREMENT BEN	280456	FAS 106-Contra Liab-Med.Sub.Claims	SO	(16,960)	(374)	(4,608)	(1,302)	(2,230)	(7,451)	(991)	(3)	-
2283400	POST-RETIREMENT BEN	280457	FAS 158 - CONTRA LIA - Reg Medicare	SO	(5,429)	(120)	(1,475)	(417)	(714)	(2,385)	(317)	(1)	-
2283400 Total					**0**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
2283500	PENSIONS	280350	Pension - Local 57	SO	(515)	(11)	(140)	(40)	(68)	(226)	(30)	(0)	-
2283500	PENSIONS	280355	FAS 158 Pension Liability	SO	(74,432)	(1,641)	(20,226)	(5,714)	(9,786)	(32,702)	(4,349)	(15)	-
2283500	PENSIONS	280365	FAS 158 Pension Liab-Rcls to Current	SO	515	11	140	40	68	226	30	0	-
2283500 Total					**(74,432)**	**(1,641)**	**(20,226)**	**(5,714)**	**(9,786)**	**(32,702)**	**(4,349)**	**(15)**	**-**
2284100	AC MIS OP PR-OTHER	289320	CHEHALIS WA EFSEC C02 MITIGATION OBLIG	SG	(235)	(3)	(61)	(18)	(33)	(104)	(14)	(0)	-
2284100 Total					**(235)**	**(3)**	**(61)**	**(18)**	**(33)**	**(104)**	**(14)**	**(0)**	**-**
2300000	ASSET RETIREMENT OBL	284918	ARO LIAB - TROJAN NUCLEAR PLANT	TROJD	(5,566)	(81)	(1,441)	(432)	(802)	(2,470)	(338)	(2)	-
2300000 Total					**(5,566)**	**(81)**	**(1,441)**	**(432)**	**(802)**	**(2,470)**	**(338)**	**(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)	(1,627)	(28,858)	(8,494)	(17,768)	(50,938)	(7,395)	(39)	-
2533500 Total					**(115,119)**	**(1,627)**	**(28,858)**	**(8,494)**	**(17,768)**	**(50,938)**	**(7,395)**	**(39)**	**-**
2539900	OTH DEF CR - OTHER	0	Fossil Rock Fuels Entries	SE	(5,006)	(71)	(1,255)	(369)	(773)	(2,215)	(322)	(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)	(206)	(3,659)	(1,077)	(2,253)	(6,459)	(938)	(5)	-
2539900	OTH DEF CR - OTHER	289523	Govt Coal Lease Bonus Payment Liability	SE	5,006	71	1,255	369	773	2,215	322	2	-
2539900	OTH DEF CR - OTHER	289540	Westmoreland Kemmerer Payable-NonCurr	SG	(2,239)	(33)	(584)	(175)	(318)	(994)	(134)	(1)	-
2539900	OTH DEF CR - OTHER	289913	MCI - F.O.G. WIRE LEASE	SG	(2,044)	(30)	(533)	(160)	(290)	(907)	(123)	(1)	-
2539900	OTH DEF CR - OTHER	289914	TRANSMISSION SERVICE DEPOSITS - THIRD PA	SG	(1,993)	(29)	(520)	(156)	(283)	(885)	(120)	(1)	-
2539900	OTH DEF CR - OTHER	289925	TRANSM CONST SECURITY DEPOSITS	SG	(11,480)	(168)	(2,993)	(900)	(1,629)	(5,096)	(689)	(3)	-
2539900	OTH DEF CR - OTHER	289927	Transm Deposit - Readiness Fin Security	SG	(43,780)	(642)	(11,414)	(3,432)	(6,214)	(19,436)	(2,629)	(13)	-
2539900	OTH DEF CR - OTHER	289928	Transmission Deposits-Site Control	SG	(260)	(4)	(68)	(20)	(37)	(115)	(16)	(0)	-
2539900	OTH DEF CR - OTHER	289955	Accrued Right-of-Way Obligations	SG	(2,053)	(30)	(535)	(161)	(291)	(911)	(123)	(1)	-
2539900 Total					**(78,468)**	**(1,165)**	**(20,305)**	**(6,082)**	**(11,315)**	**(34,805)**	**(4,772)**	**(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)	(3,044)	(860)	(1,473)	(4,922)	(654)	(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)

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
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)**	**(388,503)**	**(179,496)**	**(294,145)**	**(735,199)**	**(94,432)**	**(2)**	**(103,414)**
Grand Total					**(2,158,808)**	**(46,779)**	**(469,201)**	**(206,590)**	**(345,374)**	**(879,737)**	**(116,823)**	**(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	982	17,423	5,128	10,727	30,754	4,465	24	-
1823700	OTH REGA-ENERGY WEST	186802	Reg Asset-Deer Creek-EPIS Intangibles	SE	1,078	15	270	80	166	477	69	0	-
1823700	OTH REGA-ENERGY WEST	186805	Reg Asset-Deer Creek-CWIP	SE	3,960	56	993	292	611	1,752	254	1	-
1823700	OTH REGA-ENERGY WEST	186806	Reg Asset-Deer Creek-PS&I	SE	1,614	23	405	119	249	714	104	1	-
1823700	OTH REGA-ENERGY WEST	186811	Reg Asset-Deer Creek Sale-EPIS	SE	9,902	140	2,482	731	1,528	4,382	636	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	41	6	0	-
1823700	OTH REGA-ENERGY WEST	186816	Contra RA-DCM PP&E-To Joint Owners	SE	(4,699)	(66)	(1,178)	(347)	(725)	(2,079)	(302)	(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)	(1,117)	(19,808)	(5,830)	(12,196)	(34,963)	(5,076)	(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	1,675	493	1,031	2,957	429	2	-
1823700	OTH REGA-ENERGY WEST	186825	Reg Asset-Deer Creek Mine M&S	SE	4,492	63	1,126	331	693	1,987	289	2	-
1823700	OTH REGA-ENERGY WEST	186826	Reg Asset-Deer Creek-Prepaid Royalties	SE	843	12	211	62	130	373	54	0	-
1823700	OTH REGA-ENERGY WEST	186828	Reg Asset-Deer Creek-Recovery Royalties	SE	14,598	206	3,659	1,077	2,253	6,459	938	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	404	119	249	713	104	1	-
1823700	OTH REGA-ENERGY WEST	186833	Reg Asset-Deer Creek-Nonunion Severance	SE	2,770	39	694	204	428	1,226	178	1	-
1823700	OTH REGA-ENERGY WEST	186835	Reg Asset-Deer Creek-Misc Closure Costs	SE	45,112	638	11,309	3,328	6,963	19,961	2,898	15	-
1823700	OTH REGA-ENERGY WEST	186836	Contra RA-DCM Closure-To Joint Owners	SE	(3,142)	(44)	(788)	(232)	(485)	(1,390)	(202)	(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	747	220	460	1,318	191	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	-	-	-	-

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
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	1,627	28,858	8,494	17,768	50,938	7,395	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**	**1,365**	**37,610**	**9,495**	**16,704**	**58,744**	**8,239**	**66**	**(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	704	212	383	1,199	162	1	-
1823750	OTHER REG A-CHLA U4	185867	Reg Asset-Cholla U4-Safe Harbor Lease	SG	836	12	218	66	119	371	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**	**302**	**277**	**41,893**	**14**	**(594)**	**1**	**-**
1823870	DEFERRED PENSION	187017	FAS 158 Pen Liab Adj	SO	419,696	9,255	114,044	32,219	55,177	184,395	24,520	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)	(3,500)	(989)	(1,693)	(5,658)	(752)	(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	184	2,262	639	1,094	3,657	486	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	3,044	860	1,473	4,922	654	2	-
1823870 Total					**420,914**	**9,274**	**115,851**	**32,069**	**54,639**	**183,750**	**24,908**	**88**	**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	1,126	318	545	1,821	242	1	-
1823910	ENVIR CST UNDR AMORT	103420	ASTORIA YOUNGS BAY CLEANUP	SO	242	5	66	19	32	106	14	0	-
1823910	ENVIR CST UNDR AMORT	103426	SILVER BELL MINE ENVIRONMENTAL REMED	SO	5,239	116	1,424	402	689	2,302	306	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	96	27	46	155	21	0	-
1823910	ENVIR CST UNDR AMORT	103446	Astoria/Unocal (Downtown)	SO	1,023	23	278	79	135	450	60	0	-
1823910	ENVIR CST UNDR AMORT	103447	Big Fork Hydro Plant (MT)	SO	379	8	103	29	50	166	22	0	-
1823910	ENVIR CST UNDR AMORT	103448	Bridger Coal Fuel Oil Spill	SO	471	10	128	36	62	207	28	0	-
1823910	ENVIR CST UNDR AMORT	103449	Bridger FGD Pond 1 Closure	SO	601	13	163	46	79	264	35	0	-
1823910	ENVIR CST UNDR AMORT	103450	Bridger Plant Oil Spills	SO	352	8	96	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	180	51	87	290	39	0	-
1823910	ENVIR CST UNDR AMORT	103453	Eugene MGP (50% PCRP)	SO	307	7	83	24	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	53	90	301	40	0	-
1823910	ENVIR CST UNDR AMORT	103457	Idaho Falls Pole Yard	SO	1,306	29	355	100	172	574	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	168	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	656	185	317	1,060	141	0	-
1823910	ENVIR CST UNDR AMORT	103464	Powerdale Hydro Plant	SO	0	0	0	0	0	0	0	0	-

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
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	1,102	311	533	1,782	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	902	255	436	1,458	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	714	202	345	1,154	154	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	35	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	188	53	91	303	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	413	117	200	667	89	0	-
1823910	ENVIR CST UNDR AMORT	104203	Colstrip Pond	SO	1,543	34	419	118	203	678	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)	-	-	-	-	-

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
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	71	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)	(242)	(68)	(117)	(391)	(52)	(0)	-
1823910 Total					**32,180**	**763**	**9,402**	**236**	**4,549**	**15,202**	**2,021**	**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

PACIFICORP

Regulatory Assests (Actuals)
Year End: 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

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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

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
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

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
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

Regulatory Assests (Actuals)
Year End: 06/2021
Allocation Method - Factor 2020 Protocol
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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

Regulatory Assests (Actuals)
Year End: 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

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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

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
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

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
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

Regulatory Assests (Actuals)
Year End: 06/2021
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

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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

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
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

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
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

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	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	460	135	283	812	118	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)	(273)	(80)	(168)	(483)	(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	51	899	270	489	1,531	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

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
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)	(11)	(187)	(55)	(115)	(330)	(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)

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
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)**	**809**	**529**	**18,565**	**5,675**	**6,563**	**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**	**14,891**	**163,973**	**42,609**	**136,349**	**263,385**	**41,137**	**163**	**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)	(403)	(7,156)	(2,152)	(3,896)	(12,185)	(1,648)	(8)	-
1080000	AC PR DPR EL PL SR	3103000	WATER RIGHTS	SG	(14,473)	(212)	(3,773)	(1,135)	(2,054)	(6,425)	(869)	(4)	-
1080000	AC PR DPR EL PL SR	3110000	STRUCTURES AND IMPROVEMENTS	SG	(555,552)	(8,152)	(144,834)	(43,549)	(78,851)	(246,637)	(33,366)	(163)	-
1080000	AC PR DPR EL PL SR	3120000	BOILER PLANT EQUIPMENT	SG	(2,082,185)	(30,552)	(542,833)	(163,221)	(295,531)	(924,385)	(125,054)	(609)	-
1080000	AC PR DPR EL PL SR	3140000	TURBOGENERATOR UNITS	SG	(456,755)	(6,702)	(119,078)	(35,805)	(64,829)	(202,776)	(27,432)	(134)	-
1080000	AC PR DPR EL PL SR	3150000	ACCESSORY ELECTRIC EQUIPMENT	SG	(237,785)	(3,489)	(61,991)	(18,640)	(33,750)	(105,564)	(14,281)	(70)	-
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)	(3,983)	(1,198)	(2,169)	(6,783)	(918)	(4)	-
1080000	AC PR DPR EL PL SR	3302000	LAND RIGHTS	SG-P	(4,037)	(59)	(1,053)	(316)	(573)	(1,792)	(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)	(27)	(8)	(14)	(45)	(6)	(0)	-
1080000	AC PR DPR EL PL SR	3304000	FLOOD RIGHTS	SG-P	(285)	(4)	(74)	(22)	(40)	(126)	(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)	(82)	(1,451)	(436)	(790)	(2,470)	(334)	(2)	-
1080000	AC PR DPR EL PL SR	3311000	STRUCTURES AND IMPROVE-PRODUCTION	SG-P	(33,764)	(495)	(8,802)	(2,647)	(4,792)	(14,990)	(2,028)	(10)	-
1080000	AC PR DPR EL PL SR	3311000	STRUCTURES AND IMPROVE-PRODUCTION	SG-U	(2,521)	(37)	(657)	(198)	(358)	(1,119)	(151)	(1)	-
1080000	AC PR DPR EL PL SR	3312000	STRUCTURES AND IMPROVE-FISH/WILDLIFE	SG-P	(34,182)	(502)	(8,911)	(2,680)	(4,852)	(15,175)	(2,053)	(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)	(1,995)	(600)	(1,086)	(3,397)	(460)	(2)	-
1080000	AC PR DPR EL PL SR	3313000	STRUCTURES AND IMPROVE-RECREATION	SG-U	(1,208)	(18)	(315)	(95)	(171)	(536)	(73)	(0)	-
1080000	AC PR DPR EL PL SR	3320000	"RESERVOIRS, DAMS & WATERWAYS"	SG-P	(1,648)	(24)	(430)	(129)	(234)	(732)	(99)	(0)	-
1080000	AC PR DPR EL PL SR	3320000	"RESERVOIRS, DAMS & WATERWAYS"	SG-U	(18,728)	(275)	(4,883)	(1,468)	(2,658)	(8,314)	(1,125)	(5)	-
1080000	AC PR DPR EL PL SR	3321000	"RESERVOIRS, DAMS, & WTRWYS-PRODUCTION"	SG-P	(200,863)	(2,947)	(52,366)	(15,746)	(28,509)	(89,173)	(12,064)	(59)	-
1080000	AC PR DPR EL PL SR	3321000	"RESERVOIRS, DAMS, & WTRWYS-PRODUCTION"	SG-U	(33,978)	(499)	(8,858)	(2,664)	(4,823)	(15,084)	(2,041)	(10)	-
1080000	AC PR DPR EL PL SR	3322000	"RESERVOIRS, DAMS, & WTRWYS-FISH/WILDLIF	SG-P	(10,146)	(149)	(2,645)	(795)	(1,440)	(4,504)	(609)	(3)	-
1080000	AC PR DPR EL PL SR	3322000	"RESERVOIRS, DAMS, & WTRWYS-FISH/WILDLIF	SG-U	(302)	(4)	(79)	(24)	(43)	(134)	(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)	(22)	(3)	(0)	-
1080000	AC PR DPR EL PL SR	3330000	"WATER WHEELS, TURB & GENERATORS"	SG-P	(53,190)	(780)	(13,867)	(4,170)	(7,549)	(23,614)	(3,195)	(16)	-
1080000	AC PR DPR EL PL SR	3330000	"WATER WHEELS, TURB & GENERATORS"	SG-U	(21,932)	(322)	(5,718)	(1,719)	(3,113)	(9,737)	(1,317)	(6)	-
1080000	AC PR DPR EL PL SR	3340000	ACCESSORY ELECTRIC EQUIPMENT	SG-P	(35,244)	(517)	(9,188)	(2,763)	(5,002)	(15,646)	(2,117)	(10)	-
1080000	AC PR DPR EL PL SR	3340000	ACCESSORY ELECTRIC EQUIPMENT	SG-U	(7,354)	(108)	(1,917)	(576)	(1,044)	(3,265)	(442)	(2)	-
1080000	AC PR DPR EL PL SR	3347000	ACCESSORY ELECT EQUIP - SUPV & ALARM	SG-P	(2,765)	(41)	(721)	(217)	(393)	(1,228)	(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)	(370)	(111)	(201)	(630)	(85)	(0)	-
1080000	AC PR DPR EL PL SR	3360000	"ROADS, RAILROADS & BRIDGES"	SG-P	(10,459)	(153)	(2,727)	(820)	(1,484)	(4,643)	(628)	(3)	-
1080000	AC PR DPR EL PL SR	3360000	"ROADS, RAILROADS & BRIDGES"	SG-U	(1,242)	(18)	(324)	(97)	(176)	(551)	(75)	(0)	-
1080000	AC PR DPR EL PL SR	3402000	LAND RIGHTS	SG	11,909	175	3,105	934	1,690	5,287	715	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)	(4,573)	(1,375)	(2,489)	(7,787)	(1,053)	(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)	(64)	(1,129)	(340)	(615)	(1,923)	(260)	(1)	-
1080000	AC PR DPR EL PL SR	3430000	PRIME MOVERS	SG	(15,985)	(235)	(4,167)	(1,253)	(2,269)	(7,096)	(960)	(5)	-
1080000	AC PR DPR EL PL SR	3440000	GENERATORS	SG	(93,142)	(1,367)	(24,282)	(7,301)	(13,220)	(41,350)	(5,594)	(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)	(1,088)	(327)	(592)	(1,853)	(251)	(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)	(484)	(146)	(263)	(824)	(111)	(1)	-
1080000	AC PR DPR EL PL SR	3502000	LAND RIGHTS	SG	(46,952)	(689)	(12,241)	(3,681)	(6,664)	(20,844)	(2,820)	(14)	-
1080000	AC PR DPR EL PL SR	3520000	STRUCTURES & IMPROVEMENTS	SG	(56,525)	(829)	(14,736)	(4,431)	(8,023)	(25,094)	(3,395)	(17)	-
1080000	AC PR DPR EL PL SR	3530000	STATION EQUIPMENT	SG	(525,132)	(7,705)	(136,904)	(41,165)	(74,534)	(233,132)	(31,539)	(154)	-
1080000	AC PR DPR EL PL SR	3534000	STATION EQUIPMENT, STEP-UP TRANSFORMERS	SG	(42,709)	(627)	(11,134)	(3,348)	(6,062)	(18,961)	(2,565)	(12)	-
1080000	AC PR DPR EL PL SR	3537000	STATION EQUIPMENT-SUPERVISORY & ALARM	SG	(6,424)	(94)	(1,675)	(504)	(912)	(2,852)	(386)	(2)	-
1080000	AC PR DPR EL PL SR	3540000	TOWERS AND FIXTURES	SG	(382,998)	(5,620)	(99,849)	(30,023)	(54,360)	(170,032)	(23,003)	(112)	-
1080000	AC PR DPR EL PL SR	3550000	POLES AND FIXTURES	SG	(420,047)	(6,163)	(109,508)	(32,927)	(59,619)	(186,479)	(25,228)	(123)	-
1080000	AC PR DPR EL PL SR	3560000	OVERHEAD CONDUCTORS & DEVICES	SG	(515,770)	(7,568)	(134,463)	(40,431)	(73,205)	(228,976)	(30,977)	(151)	-
1080000	AC PR DPR EL PL SR	3570000	UNDERGROUND CONDUIT	SG	(1,356)	(20)	(353)	(106)	(192)	(602)	(81)	(0)	-
1080000	AC PR DPR EL PL SR	3580000	UNDERGROUND CONDUCTORS & DEVICES	SG	(3,312)	(49)	(863)	(260)	(470)	(1,470)	(199)	(1)	-
1080000	AC PR DPR EL PL SR	3590000	ROADS AND TRAILS	SG	(5,205)	(76)	(1,357)	(408)	(739)	(2,311)	(313)	(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)	-	-	-

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	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)	-	-	-	-	-	-	-

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	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)	(60)	(18)	(37)	(105)	(15)	(0)	-
1080000	AC PR DPR EL PL SR	3900000	STRUCTURES AND IMPROVEMENTS	SG	(2,959)	(43)	(771)	(232)	(420)	(1,314)	(178)	(1)	-
1080000	AC PR DPR EL PL SR	3900000	STRUCTURES AND IMPROVEMENTS	SO	(31,737)	(700)	(8,624)	(2,436)	(4,172)	(13,944)	(1,854)	(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)	(215)	(65)	(117)	(366)	(49)	(0)	-
1080000	AC PR DPR EL PL SR	3910000	OFFICE FURNITURE	SO	(6,911)	(152)	(1,878)	(531)	(909)	(3,036)	(404)	(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)	(292)	(88)	(159)	(497)	(67)	(0)	-
1080000	AC PR DPR EL PL SR	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	SO	(24,033)	(530)	(6,530)	(1,845)	(3,160)	(10,559)	(1,404)	(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)	(5)	(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)	(141)	(19)	(0)	-
1080000	AC PR DPR EL PL SR	3920100	1/4 TON MINI-PICKUPS AND VANS	SO	(455)	(10)	(124)	(35)	(60)	(200)	(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)	-	-	-	-	-	-	-

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)	(4)	(7)	(21)	(3)	(0)	-
1080000	AC PR DPR EL PL SR	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	SG	(4,464)	(66)	(1,164)	(350)	(634)	(1,982)	(268)	(1)	-
1080000	AC PR DPR EL PL SR	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	SO	(718)	(16)	(195)	(55)	(94)	(315)	(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)	(68)	(10)	(0)	-
1080000	AC PR DPR EL PL SR	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	SG	(3,604)	(53)	(939)	(282)	(511)	(1,600)	(216)	(1)	-
1080000	AC PR DPR EL PL SR	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	SO	(201)	(4)	(55)	(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)	(1)	(1)	(0)	(0)	-
1080000	AC PR DPR EL PL SR	3920600	DUMP TRUCKS	SG	(2,117)	(31)	(552)	(166)	(300)	(940)	(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)	(103)	(321)	(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)	(182)	(25)	(0)	-
1080000	AC PR DPR EL PL SR	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	SO	(34)	(1)	(9)	(3)	(5)	(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)	(295)	(83)	(143)	(477)	(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)	(695)	(209)	(378)	(1,183)	(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)	(168)	(2,980)	(896)	(1,622)	(5,074)	(686)	(3)	-
1080000	AC PR DPR EL PL SR	3940000	"TLS, SHOP, GAR EQUIPMENT"	SO	(1,461)	(32)	(397)	(112)	(192)	(642)	(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)	(281)	(41)	(0)	-
1080000	AC PR DPR EL PL SR	3950000	LABORATORY EQUIPMENT	SG	(3,621)	(53)	(944)	(284)	(514)	(1,608)	(217)	(1)	-

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	3950000	LABORATORY EQUIPMENT	SO	(2,780)	(61)	(755)	(213)	(365)	(1,221)	(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)	(146)	(20)	(0)	-
1080000	AC PR DPR EL PL SR	3960300	AERIAL LIFT PB TRUCKS, 10000#-16000# GVW	SO	(1,089)	(24)	(296)	(84)	(143)	(479)	(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)	(154)	(46)	(84)	(262)	(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)	(320)	(96)	(174)	(545)	(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)	(130)	(2,304)	(693)	(1,254)	(3,924)	(531)	(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)	(81)	(11)	(0)	-
1080000	AC PR DPR EL PL SR	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	SO	(701)	(15)	(191)	(54)	(92)	(308)	(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)	(657)	(197)	(358)	(1,119)	(151)	(1)	-
1080000	AC PR DPR EL PL SR	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	SO	(264)	(6)	(72)	(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)	(1,136)	(20,178)	(6,067)	(10,986)	(34,362)	(4,649)	(23)	-
1080000	AC PR DPR EL PL SR	3970000	COMMUNICATION EQUIPMENT	SO	(42,483)	(937)	(11,544)	(3,261)	(5,585)	(18,665)	(2,482)	(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)	(790)	(238)	(430)	(1,346)	(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)	-	-	-

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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)	(374)	(113)	(204)	(637)	(86)	(0)	-
1080000	AC PR DPR EL PL SR	3980000	MISCELLANEOUS EQUIPMENT	SO	(1,414)	(31)	(384)	(109)	(186)	(621)	(83)	(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)**	**(251,238)**	**(2,822,212)**	**(790,204)**	**(1,274,573)**	**(3,948,699)**	**(555,331)**	**(1,822)**	**-**
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	339	96	164	548	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)	(1,816)	(546)	(989)	(3,093)	(418)	(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	282	5,003	1,504	2,723	8,519	1,152	6	-
1085000	AC PR DPR-ACCRUAL	145149	TRANSMISSION PLANT ACCUMULATED DEPR NON-	SG	5,037	74	1,313	395	715	2,236	303	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**	**6,824**	**1,949**	**3,331**	**10,171**	**1,374**	**5**	**2,104**
Grand Total					**(9,626,762)**	**(250,581)**	**(2,815,387)**	**(790,040)**	**(1,271,243)**	**(3,947,055)**	**(552,744)**	**(1,816)**	**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)	(81)	(1,434)	(431)	(781)	(2,442)	(330)	(2)	-
1110000	AC PR AMR EL PT SR	3020000	FRANCHISES AND CONSENTS	SG-P	(114,429)	(1,679)	(29,832)	(8,970)	(16,241)	(50,801)	(6,872)	(33)	-
1110000	AC PR AMR EL PT SR	3020000	FRANCHISES AND CONSENTS	SG-U	(6,141)	(90)	(1,601)	(481)	(872)	(2,726)	(369)	(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)	(248)	(4,398)	(1,323)	(2,395)	(7,490)	(1,013)	(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)	(2,997)	(847)	(1,450)	(4,846)	(644)	(2)	-
1110000	AC PR AMR EL PT SR	3031080	FUEL MGMT SYSTEM	SO	(3,293)	(73)	(895)	(253)	(433)	(1,447)	(192)	(1)	-
1110000	AC PR AMR EL PT SR	3031230	AUTOMATE POLE CARD SYSTEM	SO	(4,410)	(97)	(1,198)	(339)	(580)	(1,937)	(258)	(1)	-
1110000	AC PR AMR EL PT SR	3031680	DISTRIBUTION AUTOMATION PILOT	SO	(13,886)	(306)	(3,773)	(1,066)	(1,826)	(6,101)	(811)	(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)	(3,510)	(43,248)	(12,218)	(20,924)	(69,927)	(9,298)	(33)	-
1110000	AC PR AMR EL PT SR	3032130	PROD & TRANS PLANT	SG	(195)	(3)	(51)	(15)	(28)	(86)	(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)	(451)	(127)	(218)	(729)	(97)	(0)	-
1110000	AC PR AMR EL PT SR	3032270	ENTERPRISE DATA WAREHOUSE	SO	(5,877)	(130)	(1,597)	(451)	(773)	(2,582)	(343)	(1)	-
1110000	AC PR AMR EL PT SR	3032330	FIELDNET PRO METER READING SYST -HRP REP	SO	(2,908)	(64)	(790)	(223)	(382)	(1,278)	(170)	(1)	-
1110000	AC PR AMR EL PT SR	3032340	FACILITY INSPECTION REPORTING SYSTEM	SO	(2,000)	(44)	(543)	(154)	(263)	(879)	(117)	(0)	-
1110000	AC PR AMR EL PT SR	3032360	2002 GRID NET POWER COST MODELING	SO	(8,958)	(198)	(2,434)	(688)	(1,178)	(3,936)	(523)	(2)	-
1110000	AC PR AMR EL PT SR	3032450	MID OFFICE IMPROVEMENT PROJECT	SO	(10,561)	(233)	(2,870)	(811)	(1,388)	(4,640)	(617)	(2)	-
1110000	AC PR AMR EL PT SR	3032510	OPERATIONS MAPPING SYSTEM	SO	(10,386)	(229)	(2,822)	(797)	(1,365)	(4,563)	(607)	(2)	-
1110000	AC PR AMR EL PT SR	3032530	POLE ATTACHMENT MGMT SYSTEM	SO	(1,892)	(42)	(514)	(145)	(249)	(831)	(111)	(0)	-
1110000	AC PR AMR EL PT SR	3032590	SUBSTATION/CIRCUIT HISTORY OF OPERATIONS	SO	(2,416)	(53)	(656)	(185)	(318)	(1,061)	(141)	(0)	-
1110000	AC PR AMR EL PT SR	3032600	SINGLE PERSON SCHEDULING	SO	(13,003)	(287)	(3,533)	(998)	(1,709)	(5,713)	(760)	(3)	-
1110000	AC PR AMR EL PT SR	3032640	TIBCO SOFTWARE	SO	(6,371)	(140)	(1,731)	(489)	(838)	(2,799)	(372)	(1)	-
1110000	AC PR AMR EL PT SR	3032680	TRANSMISSION WHOLESALE BILLING SYSTEM	SG	(1,599)	(23)	(417)	(125)	(227)	(710)	(96)	(0)	-
1110000	AC PR AMR EL PT SR	3032690	UTILITY INTERNATIONAL FORECASTING MODEL	SO	(669)	(15)	(182)	(51)	(88)	(294)	(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)	(1,897)	(570)	(1,033)	(3,231)	(437)	(2)	-
1110000	AC PR AMR EL PT SR	3032770	NORTH UMPQUA - SETTLEMENT AGREEMENT	SG	(235)	(3)	(61)	(18)	(33)	(104)	(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)	(701)	(198)	(339)	(1,133)	(151)	(1)	-
1110000	AC PR AMR EL PT SR	3032860	WEB SOFTWARE	SO	(6,320)	(139)	(1,717)	(485)	(831)	(2,777)	(369)	(1)	-
1110000	AC PR AMR EL PT SR	3032900	IDAHO TRANSMISSION CUSTOMER-OWNED ASSET	SG	(3,507)	(51)	(914)	(275)	(498)	(1,557)	(211)	(1)	-
1110000	AC PR AMR EL PT SR	3032990	P8DM - FILENET P8 DOCUMENT MANAGEMENT (E	SO	(5,827)	(128)	(1,583)	(447)	(766)	(2,560)	(340)	(1)	-
1110000	AC PR AMR EL PT SR	3033090	STEAM PLANT INTANGIBLE ASSETS	SG	(31,689)	(465)	(8,261)	(2,484)	(4,498)	(14,068)	(1,903)	(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)	(1,081)	(305)	(523)	(1,748)	(232)	(1)	-
1110000	AC PR AMR EL PT SR	3033220	MONARCH EMS/SCADA	SO	(15,202)	(335)	(4,131)	(1,167)	(1,999)	(6,679)	(888)	(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)	(167)	(557)	(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)	(82)	(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)	(414)	(5,100)	(1,441)	(2,468)	(8,246)	(1,097)	(4)	-
1110000	AC PR AMR EL PT SR	3033320	CAS - CONTROL AREA SCHEDULING (TRANSM)	SG	(9,971)	(146)	(2,599)	(782)	(1,415)	(4,426)	(599)	(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)	(204)	(61)	(111)	(347)	(47)	(0)	-
1110000	AC PR AMR EL PT SR	3033390	RMT TRADE SYSTEM	SO	(923)	(20)	(251)	(71)	(121)	(406)	(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)	-	-

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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)	(402)	(7,144)	(2,148)	(3,889)	(12,165)	(1,646)	(8)	-
1110000	AC PR AMR EL PT SR	3034900	MISC - MISCELLANEOUS	SO	(1,234)	(27)	(335)	(95)	(162)	(542)	(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)	(342)	(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)	(337)	(95)	(163)	(545)	(72)	(0)	-
1110000	AC PR AMR EL PT SR	3316000	STRUCTURES - LEASE IMPROVEMENTS	SG-P	(3,139)	(46)	(818)	(246)	(446)	(1,394)	(189)	(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)	(516)	(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)**	**(14,704)**	**(201,535)**	**(55,407)**	**(91,068)**	**(288,250)**	**(40,579)**	**(133)**	**-**
Grand Total					**(691,674)**	**(14,704)**	**(201,535)**	**(55,407)**	**(91,068)**	**(288,250)**	**(40,579)**	**(133)**	**-**

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	136	1,671	472	808	2,701	359	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	748	211	362	1,210	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	27	470	138	290	830	121	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	400	7,095	2,088	4,369	12,524	1,818	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	-	-	-	-	-	-

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
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	126	37	77	222	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	284	84	175	502	73	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	531	150	257	859	114	0	-
1901000	ACCUM DEF INC TAX	287326	DTA 720.500 Severance Accrual - Cash Ba	SO	848	19	231	65	112	373	50	0	-
1901000	ACCUM DEF INC TAX	287327	DTA 720.300 Pension/Retirement Accrual -	SO	396	9	108	30	52	174	23	0	-
1901000	ACCUM DEF INC TAX	287332	DTA 505.600 Vacation Accrual-Cash Basis	SO	8,479	187	2,304	651	1,115	3,725	495	2	-
1901000	ACCUM DEF INC TAX	287337	DTA 715.105 MCI F.O.G. WIRE LEASE	SG	503	7	131	39	71	223	30	0	-
1901000	ACCUM DEF INC TAX	287338	DTA415.110 Def Reg Asset-Transmission Sr	SG	490	7	128	38	70	218	29	0	-
1901000	ACCUM DEF INC TAX	287340	DTA 220.100 Bad Debts Allowance - Cash B	BADDEBT	4,687	96	2,273	690	34	1,342	253	-	-
1901000	ACCUM DEF INC TAX	287341	DTA 910.530 Injuries & Damages Accrual -	SO	63,041	1,390	17,130	4,839	8,288	27,698	3,683	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	400	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	903	266	556	1,594	231	1	-
1901000	ACCUM DEF INC TAX	287437	DTA Net Operating Loss Carryforwrd-State	SO	66,982	1,477	18,201	5,142	8,806	29,429	3,913	14	-
1901000	ACCUM DEF INC TAX	287441	DTA 605.100 Trojan Decom Cost-Regulatory	TROJD	1,299	19	336	101	187	576	79	0	-
1901000	ACCUM DEF INC TAX	287449	DTA Federal Detriment of State NOL	SO	(14,100)	(311)	(3,831)	(1,082)	(1,854)	(6,195)	(824)	(3)	-
1901000	ACCUM DEF INC TAX	287460	DTA 720.800 FAS 158 Pension Liability	SO	18,300	404	4,973	1,405	2,406	8,040	1,069	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	247	73	152	436	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	572	168	352	1,010	147	1	-
1901000	ACCUM DEF INC TAX	287706	DTL 610.100 COAL MINE DEVT PMI	SE	(506)	(7)	(127)	(37)	(78)	(224)	(32)	(0)	-
1901000	ACCUM DEF INC TAX	287720	DTL 610.100 PMI DEV'T COST AMORT	SE	(264)	(4)	(66)	(19)	(41)	(117)	(17)	(0)	-
1901000	ACCUM DEF INC TAX	287722	DTL 505.510 PMI VAC ACCRUAL	SE	229	3	57	17	35	101	15	0	-
1901000	ACCUM DEF INC TAX	287723	DTL 205.411 PMI SEC. 263A	SE	(405)	(6)	(102)	(30)	(63)	(179)	(26)	(0)	-
1901000	ACCUM DEF INC TAX	287726	DTL PMI PP&E	SE	(6,854)	(97)	(1,718)	(506)	(1,058)	(3,033)	(440)	(2)	-
1901000	ACCUM DEF INC TAX	287735	DTL 910.905 PMI COST DEPLETION	SE	(496)	(7)	(124)	(37)	(77)	(220)	(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	163	48	101	288	42	0	-
1901000	ACCUM DEF INC TAX	287970	DTL 415.815 Insurance Rec Accruals	SO	(28,336)	(625)	(7,700)	(2,175)	(3,725)	(12,450)	(1,655)	(6)	-
1901000 Total					**593,847**	**12,650**	**143,129**	**52,973**	**85,442**	**240,397**	**31,250**	**38**	**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)	(2,172)	(38,585)	(11,602)	(21,007)	(65,706)	(8,889)	(43)	-
2811000 Total					**(148,004)**	**(2,172)**	**(38,585)**	**(11,602)**	**(21,007)**	**(65,706)**	**(8,889)**	**(43)**	**-**
2820000	AC DEF INCTX-PROPT	287704	DTL 105.143/165 Basis Diff - Intangibles	SNP	(962)	(20)	(246)	(72)	(126)	(440)	(57)	(0)	(0)
2820000 Total					**(962)**	**(20)**	**(246)**	**(72)**	**(126)**	**(440)**	**(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)	(654)	(193)	(403)	(1,155)	(168)	(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	51	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)**	**(673,533)**	**(169,150)**	**(401,007)**	**(1,224,637)**	**(162,908)**	**(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)	(922)	(260)	(446)	(1,490)	(198)	(1)	-
2831000	AC DEF IN TX UTIL	286909	DTL 720.815 Post-Retirement Asset	SO	(4,241)	(94)	(1,152)	(326)	(558)	(1,863)	(248)	(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)	(122)	(37)	(66)	(207)	(28)	(0)	-
2831000	AC DEF IN TX UTIL	286919	DTL 210.170 - Prepaid - FSA O&M - West	SG	(124)	(2)	(32)	(10)	(18)	(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)	(556)	(157)	(269)	(899)	(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)	(7,791)	(2,201)	(3,769)	(12,597)	(1,675)	(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)

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	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)	(283)	(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)	(132)	(440)	(59)	(0)	-
2831000	AC DEF IN TX UTIL	287675	DTL 740.100 Post Merger Loss-Reacq Debt	SNP	(762)	(16)	(195)	(57)	(100)	(348)	(45)	(0)	(0)
2831000	AC DEF IN TX UTIL	287708	DTL 210.200 PREPAID PROPERTY TAXES	GPS	(5,113)	(113)	(1,389)	(392)	(672)	(2,246)	(299)	(1)	-
2831000	AC DEF IN TX UTIL	287738	DTL 320.270 Reg Asset FAS 158 Pension	SO	(103,189)	(2,275)	(28,040)	(7,921)	(13,566)	(45,337)	(6,029)	(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)	(974)	(17,280)	(5,086)	(10,639)	(30,500)	(4,428)	(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)	(162)	(46)	(78)	(261)	(35)	(0)	-
2831000	AC DEF IN TX UTIL	287849	DTL 415.424 ContraRA DeerCreekAband	SE	29,952	423	7,509	2,210	4,623	13,253	1,924	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)	(201)	(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)**	**(4,422)**	**(54,287)**	**(11,370)**	**(36,720)**	**(85,959)**	**(12,074)**	**(44)**	**(92,321)**
Grand Total					**(2,565,819)**	**(53,498)**	**(623,522)**	**(134,821)**	**(364,691)**	**(1,124,083)**	**(150,744)**	**(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)**	**-**

B20. CUSTOMER ADVANCES

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)	(447)	(7,943)	(2,388)	(4,325)	(13,527)	(1,830)	(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)	(1,134)	(341)	(617)	(1,931)	(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)	(992)	(17,618)	(5,298)	(9,592)	(30,002)	(4,059)	(20)	-
2520000 Total					**(104,109)**	**(1,502)**	**(28,120)**	**(8,028)**	**(14,534)**	**(45,744)**	**(6,150)**	**(30)**	**0**
Grand Total					**(104,109)**	**(1,502)**	**(28,120)**	**(8,028)**	**(14,534)**	**(45,744)**	**(6,150)**	**(30)**	**0**

REDACTED
Docket No. UE 399
Exhibit PAC/1003
Witness: Sherona L. Cheung

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Exhibit Accompanying Direct Testimony of Sherona L. Cheung

PacifiCorp's Property Tax Estimation Procedure

March 2022

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

REDACTED
Docket No. UE 399
Exhibit PAC/1004
Witness: Sherona L. Cheung

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Exhibit Accompanying Direct Testimony of Sherona L. Cheung

Wage and Employee Benefits Wage Escalators

March 2022

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

REDACTED
Docket No. UE 399
Exhibit PAC/1005
Witness: Sherona L. Cheung

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Exhibit Accompanying Direct Testimony of Sherona L. Cheung

IHS Markit Escalation Indices

March 2022

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REDACTED
Docket No. UE 399
Exhibit PAC/1006
Witness: Sherona L. Cheung

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Exhibit Accompanying Direct Testimony of Sherona L. Cheung

Transmission Wheeling - Facebook Support

March 2022

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

REDACTED
Docket No. UE 399
Exhibit PAC/1007
Witness: Sherona L. Cheung

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Exhibit Accompanying Direct Testimony of Sherona L. Cheung

Bridger Mine Reclamation Support

March 2022

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

REDACTED
Docket No. UE 399
Exhibit PAC/1008
Witness: Sherona L. Cheung

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Exhibit Accompanying Direct Testimony of Sherona L. Cheung

Regulatory Assets & Liabilities Adjustment Support

March 2022

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

Docket No. UE 399
Exhibit PAC/1100
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Robert M. Meredith

March 2022

TABLE OF CONTENTS

ATTACHED EXHIBITS

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 Robert M. Meredith. My business address is 825 NE Multnomah Street, Suite 2000, Portland, Oregon 97232. My present position is Director, Pricing and Tariff Policy.

Q. Briefly describe your education and professional experience.

A. I have a Bachelor of Science degree in Business Administration and a minor in Economics from Oregon State University. In addition to my formal education, I have attended various industry-related seminars. I have worked for the Company for 17 years in various roles of increasing responsibility in the Customer Service, Regulation, and Integrated Resource Planning departments. I have over 11 years of experience preparing cost of service and pricing related analyses for all of the six states that PacifiCorp serves. In March 2016, I became Manager, Pricing and Cost of Service. In February 2022, I assumed my present title.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. What are your responsibilities in these proceedings?

A. I am responsible for the Company's proposed revenue requirement for each of the unbundled service categories, the Company's functionalization procedures, the Oregon Marginal Cost Study and the design of the Company's proposed prices in this proceeding. The proposed tariffs incorporate the Company's proposed price increase and are designed consistent with the Commission's rules under Oregon Administrative Rule (OAR) 860-038-0200. I am sponsoring the Company's Oregon electric tariff schedules submitted for approval in this filing. Exhibit PAC/1101 contains the proposed tariffs.

Q. Please summarize your testimony.

A. The overall rate increase proposed by the Company in this case, including the effect of rebalancing the Rate Mitigation Adjustment (RMA) and eliminating the separate charge for the Oregon Corporate Activity Tax Recovery Adjustment (OCAT) (both discussed later in my testimony), is $82.2 million or 6.6 percent. The Company is proposing a base rate spread that is consistent with the cost of service study in this case. The Company's rate spread proposes continued use of the RMA to achieve a rate increase on January 1, 2023, where no customer rate class will see a rate increase more than double the average percent increase.

For rate design, the Company proposes keeping the same unbundled rate structure amongst prices for all schedules, except residential. For residential customers, the Company proposes increasing the single-family basic charge from $9.50 to $12 per month and replacing the inverted block energy charge structure with seasonal rates where winter prices are lower than summer prices.

III. UNBUNDLED CLASS REVENUE REQUIREMENTS

Q. Please identify Exhibit PAC/1102 and explain what it shows.

A. Exhibit PAC/1102 shows the Company's proposed revenue requirement for each of the unbundled service categories required by OAR 860-038-0200: Generation (also referred to as Production), Transmission, Distribution, Ancillary Services, Consumer Services—Billing, Consumer Services—Metering, Consumer Services—Other, Retail Services, and Investment in Public Purposes.

No revenue requirement is shown for the Retail Services or Investment in Public Purposes categories. The Company separately accounts for the costs associated with unregulated retail activities and is not seeking regulatory cost recovery for these items. Public purpose revenues are collected under a separate tariff.

Q. How was the revenue requirement determined for each of the unbundled categories?

A. Rate base balances, revenues and expenses were either assigned or allocated to unbundled categories in accordance with Oregon regulations.[1] Traditional revenue requirement methodology, (i.e., recovery of costs plus a return on rate base), was then used to determine a revenue requirement for each category. Rate base balances, revenues and expenses are from PacifiCorp's Oregon Results of Operations Report, as prepared under the direction of Ms. Sherona L. Cheung. The application of PacifiCorp's proposed rate increase is shown on page 2 of Exhibit PAC/1102.

Q. Please identify Exhibit PAC/1103 and explain what it shows.

A. Page 1 of Exhibit PAC/1103 is the summary page from PacifiCorp's December 2021 Functionalized Oregon Results of Operations Report (Functionalized Oregon Results of Operations Report) and is the basis for the unbundled revenue requirement in Exhibit PAC/1102. It separates the results of operations into the unbundled categories identified above.

[1] *See* OAR 860-038-0200.

Q. Please explain how the rate base balances, revenues and expenses in the Functionalized Oregon Results of Operations Report were apportioned among the unbundled categories.

A. The detail of PacifiCorp's Functionalized Results of Operations Report by Federal Energy Regulatory Commission (FERC) account is found on pages 2 through 22 of Exhibit PAC/1103. The functionalization procedures in this case are consistent with those approved in Order 01-787 and implemented in Advice No. 01-020. Functional factors employed in the development of these results are provided in Exhibit PAC/1104.

Q. How did PacifiCorp determine the revenue requirement for Ancillary Services?

A. The revenue requirement for Ancillary Services was estimated by applying PacifiCorp's prices for Regulation and Frequency Response Service, Spinning Reserve Service, and Supplemental Reserve Service to the relevant billing determinants of PacifiCorp's total Oregon retail load. This is shown in Exhibit PAC/1105. The costs associated with providing these services are included in the Generation function. The estimated revenue for Ancillary Services is treated as an offsetting revenue credit against the Generation revenue requirement.

Q. Please identify Exhibit PAC/1106.

A. Exhibit PAC/1106 contains a summary from PacifiCorp's State of Oregon December 2023 Marginal Cost Study (Marginal Cost Study). The Marginal Cost Study is described in more detail later in my testimony.

Q. Please identify Exhibit PAC/1107 and explain what it shows.

A. Page 1 of Exhibit PAC/1107 is the derivation of functionalized class revenue requirements and a comparison with current revenues. This exhibit is based on the results of both the Functionalized Oregon Results of Operations Report and the Marginal Cost Study. Present class revenues are shown on line 1 and megawatt-hours (MWh) are shown on line 2. Full long-run marginal costs for each customer class, separated by function, are shown on lines 4 through 12. Lines 14 through 25 show each class' share of total marginal costs for each function as well as each class' share of revenue and MWh. Lines 28 through 40 show the assignment of functional revenue requirement. The total revenue requirement for each unbundled category, as determined earlier, is shown in the total column. The total for each function is then allocated to a particular customer class based on that class' share of total marginal cost for that function. For example, the residential class accounts for 43.20 percent of generation marginal costs and is assigned 43.20 percent of the generation revenue requirement. Regulatory and franchise fees are considered part of the distribution function; however, for the purpose of assigning cost responsibility, the fees have been broken out separately. Regulatory and franchise fees have been assigned on the basis of class revenue. Lines 42 through 50 compare the total revenue requirement by class to the present class revenues collected from base rates as shown on line 1.

Q. Please explain what is shown on pages 2 and 3 of Exhibit PAC/1107.

A. Pages 2 and 3 of Exhibit PAC/1107 provide a reconciliation between Operating Revenues and Target Revenue Requirement, as shown on page 1 of this exhibit, with those shown in Exhibits PAC/1102 and PAC/1103. Not all customer classes are included in the Marginal Cost Study. Page 2 of Exhibit PAC/1107 accounts for all

Oregon test period revenue sources. Page 3 accounts for all revenue sources included in the Target Revenue Requirement.

IV. MARGINAL COST STUDY

Q. Please describe PacifiCorp's Marginal Cost Study that accompanies this filing.

A. The Marginal Cost Study is found in Exhibit PAC/1108. This study shows, by customer class, PacifiCorp's marginal cost of resources required to produce one additional unit of electricity, or to add one additional customer. Exhibit PAC/1108 contains a marginal cost and circuit model procedures narrative, various summary tables, and supporting calculations.

Q. Is this Marginal Cost Study similar to studies the Company has previously filed?

A. Yes. This study is similar to the cost of service study the Company presented in docket UE 374 (2021 Rate Case).

Q. How are marginal costs calculated?

A. One-year marginal costs include only changes in operating costs while 10-year and 20-year marginal costs also include the cost of expanding facilities. The costs of these added facilities result in long-run costs that are higher than short-run costs. Short-run costs include only one year of generation energy costs and some billing costs. They do not include any demand-related generation, transmission or distribution costs. A detailed description of marginal cost procedures is included in pages 1 through 14 of Exhibit PAC/1108.

Q. Please describe the marginal cost summary tables included in pages 15 through 22 of Exhibit PAC/1108.

A. Tables 1 and 2 of Exhibit PAC/1108 summarize the one-year, 10-year and 20-year marginal costs on a mills-per-kilowatt-hour (kWh) or dollars-per-customer basis. Table 3 summarizes the unit costs based on the results of the long-run (20-year) marginal cost study. Unit costs are shown for generation, transmission, distribution, and various customer service functional categories. Table 3 also includes energy usage, peak demand, and number of customers by customer class for the 12-month period ending December 31, 2023 test period. This information is used to calculate the annual long-run marginal costs by class shown at the bottom of Table 3.

Q. Please explain how generation marginal costs are calculated.

A. Marginal generation costs in this study are based on the Company's currently approved Oregon avoided cost calculations. New resource costs are based on the fixed and variable cost of a combined cycle combustion turbine, which operates as a base load unit. Recognizing that base load generation produces the dual products of capacity and energy, capacity costs are determined using the fixed costs of a simple cycle combustion turbine. Generation energy costs are calculated by combining the remaining fixed and all variable costs of the combined cycle turbine plus the marginal cost of Oregon's Renewable Portfolio Standard (RPS) compliance. The marginal cost of RPS compliance is based upon the forecast incremental cost of compliance multiplied by the RPS compliance obligation percentage in each year. The compliance obligation is 20 percent for 2023 to 2024, 27 percent for 2025 to 2029, 35 percent for 2030 to 2034, 45 percent for 2035 to 2039, and 50 percent for 2040 and beyond. Marginal generation capacity and energy costs are summarized on Table 4 of Exhibit PAC/1108.

Q. How are transmission costs calculated?

A. Transmission costs are based on a five-year analysis of forecasted expenditures. Expenditures identified as growth-related are used to develop marginal transmission costs. All of these growth-related transmission investments, except bulk power lines, are classified entirely to demand. Bulk power lines are classified both to demand and energy in the same proportions as the long-run marginal costs of generation resources. Marginal transmission costs are summarized on Table 5 of Exhibit PAC/1108.

Q. Please provide a general overview of how marginal distribution costs are determined.

A. Table 6 of Exhibit PAC/1108 provides a unit cost summary by class and load size of marginal distribution costs. Distribution costs are classified into three components: (1) demand-related, shown in dollars per kilowatt (kW)/year; (2) commitment-related, shown in dollars per customer/year; and (3) billing-related, shown in dollars per customer/year. Commitment-related distribution costs consist of the costs of transformers, poles and conductors that are not determined by the level of demand customers place on the system. Demand-related distribution costs include additional costs of larger transformers, substations, poles and conductors with sufficient capacity to serve the level of demand a customer class places on the system.

Q. Please describe how the marginal costs of distribution line transformers are calculated.

A. Marginal transformer costs are calculated using a least squares regression analysis of the current installed cost versus size of the Company's commonly installed transformers. Commitment and demand costs are separated by the nature of this statistical technique. The regression provides an intercept term, which represents the commitment costs, and a slope, which represents the demand cost per kW. The regression also identifies the additional costs of a three-phase transformer over a single-phase transformer.

Q. Please describe how the marginal costs of distribution circuits are calculated.

A. Marginal costs of distribution poles and wires are calculated using the Company's Distribution Circuit Model. The circuit model focuses on several key characteristics that influence distribution cost of service. Among these are customer density, customer size and usage characteristics, and customer location on the circuit. The hypothetical circuit is constructed with seven branches of equal length using the composite line statistics and current cost estimates for Oregon. Customer locations are based on actual customer distances from the substation. The results are segregated into commitment-related and demand-related costs for each customer class. A detailed description of the updated circuit model is also included in the marginal cost procedures on pages 5 through 14 of Exhibit PAC/1108.

Q. How are substation marginal costs calculated?

A. Marginal substation costs are determined using the per kW cost of substation additions being considered for a five-year period. The cost per kW is determined by dividing the growth-related distribution substation investment in the capital budget horizon by the related increase in substation capacity. Substation marginal costs are classified entirely to demand and are allocated to customer classes based on the distribution peak load for each class weighted by the load of substations peaking in each month.

Q. What is included in the service drop category?

A. The service drop category includes the marginal cost of service drops with associated operation and maintenance (O&M). Current typical installed costs for service drops are determined for each customer load size.

Q. What is included in the metering category?

A. The metering category includes the marginal cost of metering equipment with associated O&M. Current typical installed metering costs are determined for each customer load size by analyzing service requirements, such as single- or three-phase service and voltage level. Meter O&M is based on historical expenditures.

Q. What is included in the billing and customer service/other categories?

A. This category includes the costs of billing, payment processing and debt recovery, meter reading expense, and all the remaining customer accounting and customer service activities. Marginal meter reading expense is assumed to be zero because Advance Metering Infrastructure has been deployed for almost all customers. Customer accounting and customer service expense are based on historical expenditures and are assigned to each customer class based on the various resources required to perform billing, collections, and customer service activities for different types of customers.

V. ALLOCATION OF THE FUNCTIONALIZED REVENUE REQUIREMENT

Q. How is the Company proposing to allocate the functionalized revenue requirement across classes of customers in this proceeding?

A. The Company is allocating the functionalized revenue requirement to classes consistent with the Commission's Direct Access Rules. These rules indicate that "rates for any class of consumer must be based on the unbundled costs to serve that class."[2] In this filing, the Company has allocated the revenue requirement to each rate schedule based on the results of the functionalized class cost of service study. The proposed rates for each rate schedule included in the cost of service study are targeted to collect the cost of service for that rate schedule in the test period. Therefore, the proposed base rates for each class are based on the unbundled costs to serve that class.

Q. Do you have an exhibit that summarizes the functionalized results of the cost of service study?

A. Yes. Pages 1 and 2 of Exhibit PAC/1109 summarize the functionalized results of the cost of service study in column (4). This summary is provided at the level used to design rates. The cost of service for each rate schedule has been summarized into the following components: Transmission & Ancillary Services, System Usage, Distribution, Generation Energy Other Non-Net Power Costs (Non-NPC), and Generation Energy Net Power Costs (NPC).

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[2] OAR 860-038-0240(3)(b).

Q. What is the purpose of including this summary of cost components for the target functionalized revenue requirement?

A. The summary level for revenue requirement shown on pages 1 and 2 of Exhibit PAC/1109 summarizes the cost of service results into the target revenue requirement components used in rate design.

The process of unbundling the Company's proposed prices is consistent with the method the Company first implemented in docket UE 116. For each rate schedule, the functionalized costs are applied to rates as follows: distribution, billing, metering, and customer costs are included in each proposed delivery service schedule's Distribution rates; the FERC regulated transmission and ancillary services are included in each proposed delivery service schedule's Transmission & Ancillary Services rates; non-NPC generation costs are included in Schedule 200, Base Supply Service rates; and NPC are included in Schedule 201, Net Power Costs, Cost-Based Supply Service rates.

Q. Have any adjustments been made to the functionalized revenue requirement by rate schedule resulting from the cost of service study?

A. Yes. Consistent with past cases, the functionalized revenue requirement has been adjusted to remove the proposed changes to NPC collected through Schedule 201. Changes to Schedule 201 are implemented through the transition adjustment mechanism (TAM), which is a separate proceeding from this general rate case, and the Schedule 201 changes will be addressed in that proceeding. The modified cost of service results reflecting this adjustment to remove the NPC increase from the functionalized revenue requirement is shown on pages 1 and 2 of Exhibit PAC/1109.

This exhibit displays the target functionalized revenue requirement used in the design of rates proposed in this general rate case.

Q. Do the Company's proposed rates collect the target functionalized revenues?

A. Yes. The revenues calculated by multiplying the test period billing determinants by the proposed rates are summarized in column (6) on pages 1 and 2 of Exhibit PAC/1109. A direct comparison to the target functionalized revenues shown in column (5) of this exhibit shows that the calculated revenues equal the target revenues with the exception of small differences due to the rounding of rates. The detailed calculation of proposed revenues based on billing determinants and proposed rates is shown on pages 3 through 11 of Exhibit PAC/1109.

Q. Have you prepared an exhibit showing the estimated effects of the prices proposed in this general rate case?

A. Yes. Exhibit PAC/1110 shows the estimated effect of the Company's proposed prices. Table 1110-1 shows the effect of the proposed prices by delivery service rate schedule for the proposed net rate increase on January 1, 2023, of $82.2 million which includes the impact of the $4.5 million RMA rebalancing and the $6.7 million related to the elimination of the separate OCAT (both discussed later in my testimony). This table shows the effect of the price changes on both base revenues and net revenues. Base revenues show the effect before the impacts of any adjustment tariffs. Net revenues include the effect of adjustment tariffs (discussed directly below), the OCAT and the RMA.

The adder columns in Table 1110-1 show revenues from adjustment tariff schedules (Schedules 104, 194, 195, 198, 203, 204, 207, and 299). The adder revenue is added to base revenue to calculate net revenue including adjustment schedules. Table 1110-2 shows the calculation of the adjustment revenue included in the adder columns in Table 1110-1. These tables exclude the effects of pass-through adjustment schedules for Low Income Bill Payment Assistance Charge (Schedule 91), the Adjustment Associated with the Pacific Northwest Electric Power Planning and Conservation Act (Schedule 98), the Public Purpose Charge (Schedule 290), and the System Benefits Charge (Schedule 291). Table 1110-3 shows the present and proposed rates for each adjustment schedule.

Beginning on page 4 of Exhibit PAC/1110 are the monthly billing comparisons for each of the major delivery service rate schedules showing the customer bill impacts of the proposed prices at various levels of usage. The monthly billing comparisons in Exhibit PAC/1110 show the expected rate increases for January 1, 2023, from proposed rates. The monthly billing comparisons also include the effects of all adjustment schedules including the pass-through adjustment schedules listed above.

Q. What are the Company's rate spread objectives in this case?

A. The Company's rate spread objectives in this case are to minimize price impacts on our customers while fairly reflecting cost of service and sending proper signals about increasing costs.

Q. What is the Company's rate spread proposal in this case?

A. Based on the cost of service results and in order to achieve the Company's rate spread objectives in this case, Table 1 below summarizes the Company's proposed net percentage price changes for the major rate schedule classes.

Table 1

Residential Schedule 4	**9.1%**
General Service	
Schedule 23/723 (0-30kW)	**9.5%**
Schedule 28/728 (31-200kW)	**0.0%**
Schedule 30/730 (201-999kW)	**0.0%**
Large General Service Schedules 47/747, 48/748 (≥1,000kW)	**5.9%**
Agricultural Pumping Service Schedule 41/741	**13.2%**
Lighting Schedules	**0.0%**
Overall	**6.6%**

Under the Company's proposal, the rate change that takes effect January 1, 2023, will result in no customer rate schedule class receiving an increase greater than double the average increase or 13.2 percent. The Company's proposed rate spread strikes a balance between moderating rate impacts on customers, while sending proper price signals about increasing costs and minimizing subsidization across rate schedule classes. As a result, the Company proposes revisions to the RMA to achieve these goals.

Q. Please describe the RMA.

A. The RMA, Schedule 299, is designed to mitigate the impacts of changes in the functionalized revenue requirement on net rates across rate schedules. Net rates are the rates that customers pay once all tariff riders (including the RMA) are taken into account. The RMA is designed to be revenue neutral overall at the time a general rate case price change is implemented, resulting in RMA credits for some rate schedule classes requiring rate mitigation with offsetting RMA charges for others. The RMA was first implemented in docket UE 116 to transition to cost of service rates under

Senate Bill 1149. The Schedule 299 RMA tariff rider is included in customers' rates for delivery services in order to minimize the effect of the price change allocation across customer classes.

Q. Besides mitigation of rate changes across rate schedules, what other factors contribute to the adjustment of the RMA in a general rate case?

A. In each general rate case, the RMA must be rebalanced in order to achieve revenue neutrality so that the revenues from the RMA charges and the RMA credits are in balance. The present Schedule 299 RMA rates were designed to be revenue neutral in the calendar year 2021 test period from the Company's 2021 Rate Case; however, due to changes in rate schedule loads, present Schedule 299 RMA rates are not projected to produce revenue neutrality in the calendar year 2023 test period of this case. The present RMA rates result in RMA credits that exceed RMA charges by $4.5 million for the 2023 test period loads (see Exhibit PAC/1110, Table 1110-2, Column 11, Row 18). Consistent with previous RMA revisions, the proposed RMA rates have been designed to be revenue neutral for the 2023 test period. As a result of this realignment, the proposed net rate increase in this case is $4.5 million higher than the base revenue requirement increase.

Q. Has the RMA required rebalancing in previous general rate cases?

A. Yes. For example, in the 2021 Rate Case the RMA required a rebalancing adjustment of $0.4 million.

Q. Are there any other factors which affect the net increase proposed in this case?

A. Yes. The costs of the OCAT are now proposed to be collected through base rates, as discussed in the testimony of Ms. Cheung. The Company proposes to eliminate the separate adjustment Schedule 104 which currently collects OCAT costs from customers. This results in a net rate increase in this case that is $6.7 million less than the base increase.

Q. What is the combined effect of the RMA rebalancing and the elimination of the OCAT surcharge on the proposed increase in this case?

A. The combined impact is a proposed net rate increase that is $2.2 million less than the base revenue requirement increase (Exhibit PAC/1110, Table 1110-1).

Q. What are the present and proposed RMA revenues and rates in this case?

A. The present and proposed RMA revenues are shown in Exhibit PAC/1110, Table 1110-2, columns (11) and (12). Present and proposed RMA rates are shown in Exhibit PAC/1110, Table 1110-3, columns (11) through (16).

Q. What is the Company's RMA objective in this case?

A. The Company's RMA objective in this case is to minimize rate schedule subsidization through the RMA while minimizing impacts on customers. To limit the increase for irrigation customers to roughly twice the average price change, the Company proposes increasing the RMA credit received by irrigation customers. The Company also proposes RMA credits for residential customers to limit the net increase to about 1.4 times the average increase.

For Small General Service Schedule 23 and Large General Service Schedules 47/747 and 48/748, the Company proposes to eliminate the RMA surcharges and credit rates in order to minimize cross-subsidization. The proposed January 1 net increase for Schedule 23 is 9.5 percent and for Schedules 47/747 and 48/748 is 5.9 percent.

In light of the overall increase for customers, the Company proposes increasing the RMA for Lighting Schedules 15, 51, 53 and 54 and also for General Service Schedules 28/728, and 30/730 to hold these customers at a zero net price change.

Overall, the Company believes that these proposals result in just and reasonable rates and will minimize rate impacts.

VI. RATE DESIGN

Q. Please generally describe the process for designing rates to collect the proposed revenue requirement.

A. Proposed rates are designed to collect the target functionalized revenue requirement based on customer billing determinants including number of monthly bills, kW, and kWh consumed for the rate case test period. The billing determinants used in this case reflect the forecast test period for the 12 months ending December 2023.

Q. How are the forecast billing determinants developed?

A. Forecast test period billing determinants are developed based on the Company's forecast test period bills and energy forecasts along with the historical test period billing determinants.

A three-step process occurs in developing test period billing determinants. First, the Company forecasts monthly test period bills and energy by class and by rate schedule which is supported in the testimony of Mr. Kenneth Lee Elder, Jr.

Second, a full set of billing determinants, including all rate elements such as kW demand, load size, reactive power quantities and kWh by rate block, are retrieved at the customer invoice level from the Company's billing system for the base period—in this case, the 12 months ended June 2021. These historical billing determinants are summarized by class, rate schedule, and voltage level.

Finally, a full set of forecast billing determinants is developed using the historical base period data and the test period forecast. The forecast billing determinants are calculated based upon the ratio of historical bills and energy (temperature normalized) in the base period to the forecast bills and energy provided in the sales forecast.

Q. Have you provided an exhibit showing proposed rates and the billing determinants used to design rates?

A. Yes. Pages 3 through 11 of Exhibit PAC/1109 contain historical and forecast billing determinants along with present and proposed base rates.

Q. Please summarize the rate design changes proposed by the Company.

A. In this case, the Company is proposing to increase the single-family basic charge for residential customers from $9.50 to $12. The Company is also proposing to replace the present inverted block tier rate structure with a seasonal rate structure for residential customers.

For other rate schedules, the Company proposes to keep the same unbundled rate structures and general relationship amongst rates.

A. Residential Rate Design

Q. Please explain the proposed tariffs for residential customers.

A. Residential customers are served on Delivery Service Schedule 4. The Company proposes increasing the basic charge from its current level of $9.50 per month to $12 for single-family dwellings. This change better reflects the fixed costs of serving residential customers and more fairly apportions cost between fixed and volumetric charges. The Company also proposes to eliminate the inclining tier block structure and replace it with seasonal energy charges.

For residential customers, as well as for all classes of customers, Schedule 200, Base Supply Service, is proposed to reflect changes in the non-NPC generation revenue requirement as indicated in pages 1 and 2 of Exhibit PAC/1109.

Q. Why is the Company proposing an increase in its basic charge for most residential customers?

A. The Company's marginal cost of service study which I present as Exhibit PAC/1108 shows on Table 3 that the annual marginal cost of billing- and commitment-related cost is $346.20 or about 28.85 per month. At $9.50, the Company's present basic charge falls far short of cost. Making movement towards a cost-based basic charge is important because this helps the Company keep energy more affordable for its customers. Given a fixed level of revenue to be collected from all residential customers, an increase in the basic charge will lower energy charges. Exhibit PAC/1111 shows a breakdown of the marginal cost of billing- and commitment-related cost for single-family and multi-family residential customers.

Q. How does the Company's current and proposed basic charge compare to other utilities in Oregon?

A. The Company's current and proposed basic charge compares very favorably to the basic charges of other Oregon electric utilities. The Company examined the residential rates of 15 other utilities, which includes the other two electric investor-owned utilities in the state and 13 publicly owned electric utilities with service territory in close proximity to the Company's. Table 2 below shows those basic charges as well as an average for all 15 utilities.

Table 2: Comparison of PacifiCorp's Current and Proposed Basic Charge to Other Oregon Electric Utilities

Utility	Residential Basic Charge
Current Pacific Power	$8.00 multi-family/$9.50 single family
Proposed Pacific Power	$8.00 multi-family/$12.00 single family
Portland General Electric	$11.00
Idaho Power	$8.00
Central Electric Coop	$23.77
Central Lincoln PUD	$24.00
City of Ashland	$16.25
City of Hermiston	$18.50
City of Monmouth	$10.83
Coos-Curry Electric Coop	$28.38
Eugene Water and Electric Board	$20.50
Hood River Electric Coop	$22.50
Lane Electric Coop	$31.50
Salem Electric	$20.00
Springfield Utility Board	$15.30
Tillamook PUD	$29.00
Umatilla Electric Coop	$22.00
Average	$20.10

Note - Prices were those available from each utility's website as of December 6, 2021

The average basic charge of all 15 utilities examined is $20.10 which is well above the Company's current basic charge of $8 for multi-family and its proposed $12 for single-family.

Q. How are residential energy charges currently structured?

A. Residential energy charges use what is called an inclining block or tiered rate structure where energy usage up to a specific threshold per month receives a lower price and successive energy consumption is priced at a higher rate. Including all adjustment schedules, the first 1,000 kWh[3] in a month are 9.018 cents per kWh and all additional kWh are 11.147 cents per kWh.

Q. Historically, why have inclining block structures been used for residential customers?

A. The inclining block rate structure has been considered by some to be an effective tool for encouraging customers to save energy. The theory is that the first block covers some basic level of usage at a lower rate to help keep the overall bill affordable for customers and a second and possibly third block with a higher rate makes incremental energy usage more expensive. For a customer with usage in the higher tiers, making energy efficient choices like installing light-emitting diode lights will yield greater savings than would have been achieved under a flat energy charge rate design.

Q. Is the inclining block structure still an appropriate rate design for residential customers?

A. No, not in light of changes in the electric industry and the likelihood of further evolution in the energy landscape of the future. While well intentioned, tiered rates can result in unintended consequences, particularly as the electric industry evolves. Tiered rates are unfair, are not economically justified, and create perverse incentives. In addition, tiered rate structures can be a source of confusion for residential customers

[3] The tier block threshold is prorated so that it is higher for billing periods longer than the average month and lower for billing periods that are shorter. For example, a 28-day cycle has a tier block threshold of 920 kWh and a 34-day cycle has a tier block threshold of 1,117 kWh.

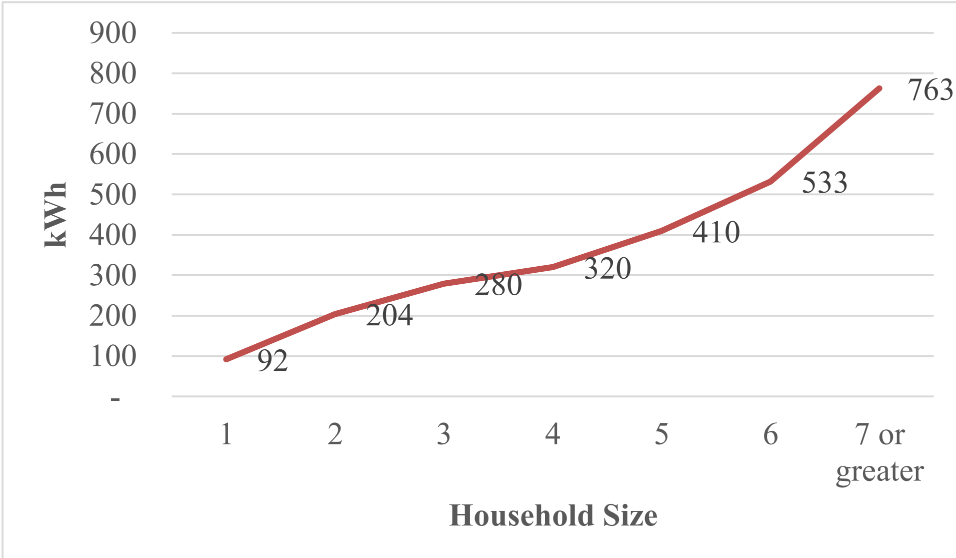
Q. How are tiered rates unfair?

A. Charging higher prices for greater usage in a given month arbitrarily benefits some customers while harming others. Customers who heat their home with natural gas or a woodstove benefit and those who choose to heat their home with electricity, or otherwise do not have access to natural gas, pay more. A bustling, multi-generational household with a large number of people living under one roof pays a higher cost for energy usage and a person living alone in an apartment pays less. A customer who chooses to buy an electric vehicle and charge it from home likely falls into the second block and pays more per kWh to fuel the vehicle while another customer who keeps their internal combustion engine vehicle stays under the first block and pays less per kWh. Effectively, inclining block rates unfairly reward some customers and punish others, often for reasons outside the customer's control or in ways that incentivize behaviors that are at odds with changes in energy policy.

Q. Do you have any evidence that larger households and customers who heat their homes with electricity end up with more usage priced at the higher cost second block?

A. Yes. From examining the data from the Company's 2019 residential customer survey, the average usage that occurred in the second block was higher for larger households. Figure 1 below shows these differences:

Figure 1: Average Monthly Second Block Usage by Household Size from PacifiCorp's 2019 Residential Customer Survey



The Company's survey results also showed that customers who used electricity as their primary fuel for heating their home had nearly three times greater usage in the second block. Table 3 below shows how usage compares for survey respondents who answered that they use electricity as the fuel for their main source of heating equipment and those who use other fuels:

Table 3: Average Monthly Usage by Primary Heating Fuel from PacifiCorp's 2019 Residential Customer Survey

Primary Heating Fuel	Average First Tier Usage (kWh)	Average Second Tier Usage (kWh)
Electricity	779	343
Other (natural gas, propane, oil, wood/pellets)	648	117

Q. Please describe why tiered rates are not economically justified.

A. There is no reason why after using 1,000 kWh in a given month that the next kWh consumed by a customer should cost more. The timing of energy consumption, both seasonally and during different hours, can affect the utility's cost of providing kWh to the customer. The load factor, or the effective utilization of kWh consumption relative to peak kW demand, can also change the average cost of providing energy. However, there is nothing special about additional overall usage in a monthly billing period that makes it more expensive for the utility to produce that next kWh of electricity.

Q. How do tiered rates create perverse incentives?

A. Relative to a flat energy charge rate structure, inclining block prices encourage customers to switch fuels to natural gas. Avista Corporation, Cascade Natural Gas Corporation, and Northwest Natural, Oregon's three natural gas providers, do not use an inclining block rate structure for residential customers for volumetric gas consumption. In other words, the price for each therm that a natural gas customer in Oregon purchases is flat and does not become more expensive with greater usage within a monthly billing period. As the result of this disparity in rate designs, PacifiCorp's customers are sent a skewed message about the economics of using electricity to heat their homes relative to natural gas.

Another unfavorable result of tiered rates is that they make residential transportation electrification less attractive. While a customer can at this time still experience "fuel" savings with charging their electric vehicle at the higher second tier price relative to purchasing gasoline, if more costs get pushed into the customer's incremental cost of energy on the second tier the economic rationale to choose an electric car is weakened.

Q. What does the Company propose for residential customers instead of the inclining tiered rate structure?

A. In light of the inequities that the tiered rate structure presents and the need for residential price signals to support the state's decarbonization goals, the Company proposes replacing the inclining block tiered rate structure with seasonal pricing. As opposed to tiered rates that make energy prices vary based upon monthly household usage, seasonal rates would make energy rates lower in winter months and higher in summer months. This structure for residential charges would better reflect the economics of energy consumption and would treat customers more fairly, regardless of household size or heating fuel used. Specifically, the Company proposes that the price for residential energy charges, including the impact of the concurrently filed TAM, would be 10.335 cents per kWh during the winter months of October through May and 12.264 cents per kWh during the summer months of June through October. Additionally, the Company proposes that the Schedule 98 Adjustment Associated with the Pacific Northwest Electric Power Planning and Conservation Act be modified to a flat 0.914 cents per kWh credit for all usage. With these changes, the net difference in between summer and winter energy charges of 1.9 cents per kWh would be very similar to the net price difference that currently exists between the first and second tier blocks of about 2.1 cents per kWh.

Q. What is the cost justification for differentiating residential rates based upon season?

A. PacifiCorp experiences its highest system loads during the summertime and wholesale market prices are often higher at this time. Examining the most recent monthly official market price curve used in the Company's TAM that was filed concurrently with this rate case, the average price at the Mid-Columbia hub between the months of June through September is forecast to be about 1.939 cents per kWh higher during the 2023 rate effective period than during the months of October through May. The Company proposes using this same differential between its summer and winter residential energy charges.

Q. How will seasonal rates send better price signals that encourage wise use of the system?

A. By charging cost-based prices that vary by season of the year, the Company's proposed rate structure will encourage customers to prioritize energy efficiency in the higher cost of service summer period. This could include installing a heat pump water heater or choosing a high efficiency air conditioner.

At the same time, the Company's rates will no longer dis-incentivize heating homes with electricity as the current tiered rate structure does. However, even at the lower proposed winter energy price, customers will still be encouraged to choose efficient heating equipment but will be sent a more accurate price signal about the incremental cost of consumption.

Q. Under this proposed seasonal rate structure, how would the economics of heating with electricity compare to heating with natural gas?

A. Table 4 below shows how the cost of operating an efficient heat pump under the present second block energy charge and under the proposed winter energy charge would compare to operating an efficient natural gas furnace with service from Cascade Natural Gas:

Table 4: Comparison of Residential Cost to Operate Heating Equipment

Fuel Type	Unit Cost		Unit Cost per Therm	Appliance Type	Appliance Efficiency	(%, COP, or AFUE)	Cost Per Therm	Δ from Natural Gas
Electric (Pacific Power Current 2nd Tier Price)	$0.11147	/kWh	$3.266071	Heat Pump	300%	C.O.P.	$1.09	**22.3%**
Electric (Pacific Power Proposed Winter Price)	$0.10335	/kWh	$3.028227	Heat Pump	300%	C.O.P.	$1.01	**13.4%**
Electric (Pacific Power Proposed Winter Price)	$0.10335	/kWh	$3.028227	Baseboard	100	%	$3.03	**240.3%**
Natural Gas (Cascade Natural Gas)	$0.85753	/Therm	$0.857530	Furnace	96%	AFUE	$0.89	

Under existing rates, a Pacific Power customer in the second block would pay about 22.3 percent more to operate an efficient heat pump than natural gas. Under the proposed winter season price, a Pacific Power customer would pay about 13.4 percent more. Significantly, the cost for a Pacific Power customer paying the proposed winter price would still pay much more than natural gas to operate an inefficient baseboard heater.

Q. Would the Company's proposed changes to residential rates disproportionately impact customers experiencing lower than average income?

A. I don't believe they would. The Company examined the data from its 2019 residential customer survey and found two trends that counterbalanced each other with respect to the Company's proposed rate design. First, usage did tend to be moderately higher on average for higher income customers. Second, lower income customers tend to use a greater proportion of their usage during the winter months. Table 5 below summarizes this finding:

Table 5: Average Usage and Winter Usage Proportion by Income Level from PacifiCorp's 2019 Residential Customer Survey

Income Level	Average Usage	Proportion of Usage that Occurs in Winter
Less than $50,000	882	72.5%
$50,000 to $74,999[1]	924	70.5%
$75,000 or more	982	69.4%

[1]Note - $67,058 was the median household income in Oregon in 2019 per the United States Census Bureau, American Community Survey

To understand the potential impact of the proposed increase in the basic charge and the move from inclining block tiered rates to seasonal rates, the Company analyzed the usage information from respondents who had a full 12 months of usage.

The analysis showed that the bill impact, including the proposed change from the concurrently filed TAM, on average was very similar for different income levels. Table 6 below summarizes this analysis:

Table 6: Average Bill Impact by Income Level from PacifiCorp's 2019 Residential Customer Survey

Income Level	Average Monthly Bill Change	% Change
Less than $50,000	$14.03	15.1%
$50,000 to $74,999[1]	$15.07	15.5%
$75,000 or more	$15.48	15.0%

[1]Note - $67,058 was the median household income in Oregon in 2019 per the United States Census Bureau, American Community Survey

Q. What change does the Company propose for the residential time of use Schedule 6 pilot and for the time of use portfolio Schedule 210?

A. For residential time of use pilot Schedule 6, the Company proposes keeping the same 14.270 cent per kWh on-peak adder and the 3.790 cent per kWh off-peak credit, and applying them to the proposed flat seasonal prices for Schedule 4. For Schedule 210, the Company proposes modifying the seasons for the time of use hours and prices to be June through September for Summer and October through May for Winter, so that they are consistent with the periods for residential seasonal pricing.

Additionally for Schedule 210, the Company proposes to eliminate the monthly Portfolio Service Charge of $1.50. This charge was originally intended to recover costs associated with the installation of a more expensive time of use meter. With customers now served with time of use capable advanced metering infrastructure meters, this charge is no longer necessary.

Q. House Bill 2475 authorizes utilities to create differential rates and programs for low-income customers. What are the Company's plans to offer such a program?

A. The Company intends to file for approval of a low-income bill assistance program soon after filing this rate case. The Company did not include a low-income bill assistance program proposal in this general rate case application because it hopes a program can be implemented sooner than the effective date for this rate case.

B. Non-Residential Rate Design

Q. What does the Company propose for the rate design for non-residential customers?

A. The Company is not proposing any changes to the underlying rate structures for non-residential customers. Prices were modified to collect the target revenue requirement and to track functionalized costs. Present and proposed rates for all schedules are detailed in Pages 3 through 11 of Exhibit PAC/1109.

VII. CONCLUSION

Q. What is your recommendation for the Commission?

A. I recommend that the Commission approve the Company's marginal cost of service study, rate spread, and rate design including its proposal to increase the basic charge for single-family residential customers to $12 and replace the tiered structure to a seasonal structure for residential energy charges.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 399
Exhibit PAC/1101
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Proposed Tariffs

March 2022

TABLE OF CONTENTS - SCHEDULES

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 4

RESIDENTIAL SERVICE
DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To single-family Residential Consumers only for all single-phase and three-phase electric requirements when all service is supplied at one point of delivery. Three-phase service will be supplied only when service is available from Company's presently existing facilities, or where such facilities can be installed under Company's Line Extension Rules, and, in any event, only when deliveries can be made by using one service for Consumer's single-phase and three-phase requirements.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge, Transmission & Ancillary Services Charge, and the System Usage Charge plus the applicable adjustments as specified in Schedule 90.

<u>Distribution Charge</u>		
Single-Family Home Basic Charge, per month	$12.00	(I)
Multi-Family Home Basic Charge, per month	$8.00	
Three Phase Demand Charge, per kW demand	$2.20	
Three Phase Minimum Demand Charge, per month	$3.80	
Distribution Energy Charge, per kWh	4.435¢	(I)
<u>Transmission & Ancillary Services Charge</u>		
Per kWh	0.918¢	(I)
<u>System Usage Charge</u>		
Schedule 200 Related, per kWh	0.066¢	(R)
T&A and Schedule 201 Related, per kWh	0.082¢	(I)

Supply Service Options

All Consumers shall pay the applicable rates under Schedule 200, Base Supply Service. Additionally, each Consumer shall specify Supply Service Schedule 201, Schedule 210, Schedule 211, Schedule 212 or Schedule 213, as appropriate and in accordance with the Applicable section of the specified rate schedule.

Franchise Fees

Franchise fees related to Schedule 200, Base Supply Service, are collected through the System Usage Charge - Schedule 200 Related rate. Franchise fees related to Transmission & Ancillary Services and franchise fees related to Schedule 201, Net Power Costs, are collected through the System Usage Charge - T&A and Schedule 201 Related rate. Franchise fees related to distribution charges are collected through distribution charges.

Special Conditions

Consumer shall so arrange his wiring as to make possible the separate metering of the three-phase demand at a location adjacent to the kWh meter. If, on November 25, 1975, any present Consumer's wiring was arranged only for combined single and three-phase demand measurement, and continues to be so arranged, such demands will be metered and billed hereunder except that the first 10 kW of such combined demand will be deducted before applying demand charges for three phase service. No new combined demand installations will be allowed such a demand deduction

(continued)

Issued March 1, 2022
Effective for service on and after January 1, 2023
Matthew McVee, Vice President, Regulation
Advice No. 22-002/Docket No. UE 399

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 5

SEPARATELY METERED ELECTRIC VEHICLE SERVICE FOR RESIDENTIAL CONSUMERS
DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To single-family Residential Consumers only for all single-phase and three-phase electric requirements supplied to electric vehicle charging installations where such service is supplied at a point of delivery separately metered from other residential service. Three-phase service will be supplied only when service is available from Company's presently existing facilities.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge, Transmission & Ancillary Services Charge, and the System Usage Charge plus the applicable adjustments as specified in Schedule 90.

Distribution Charge		
Single-Family Home Basic Charge, per month	$12.00	(I)
Multi-Family Home Basic Charge, per month	$8.00	
Three Phase Demand Charge, per kW demand	$2.20	
Three Phase Minimum Demand Charge, per month	$3.80	
Distribution Energy Charge, per kWh	4.435¢	(I)
Transmission & Ancillary Services Charge		
Per kWh	0.918¢	(I)
System Usage Charge		
Schedule 200 Related, per kWh	0.066¢	(R)
T&A and Schedule 201 Related, per kWh	0.082¢	(I)

Supply Service Options

All Consumers shall pay the applicable rates under Schedule 200, Base Supply Service. Additionally, each Consumer shall specify Supply Service Schedule 201, Schedule 210, Schedule 211, Schedule 212 or Schedule 213, as appropriate and in accordance with the Applicable section of the specified rate schedule.

Franchise Fees

Franchise fees related to Schedule 200, Base Supply Service, are collected through the System Usage Charge - Schedule 200 Related rate. Franchise fees related to Transmission & Ancillary Services and franchise fees related to Schedule 201, Net Power Costs, are collected through the System Usage Charge - T&A and Schedule 201 Related rate. Franchise fees related to distribution charges are collected through distribution charges.

Continuing Service

This Schedule is based on continuing service at each service location. Disconnect and reconnect transactions shall not operate to relieve a Consumer from minimum monthly charges.

Rules and Regulations

Service under this Schedule is subject to the General Rules and Regulations contained in the tariff of which this Schedule is a part and to those prescribed by regulatory authorities.

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 6

PILOT FOR RESIDENTIAL TIME-OF-USE SERVICE
DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Residential Consumers otherwise receiving Delivery Service under Schedule 4, in conjunction with Supply Service Schedule 201. Service under this pilot will be limited to approximately twenty-five thousand (25,000) metered points of delivery.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge, Transmission & Ancillary Services Charge and System Usage Charge plus the applicable adjustments as specified in Schedule 90 for Schedule 4.

Distribution Charge		
Single Family Home Basic Charge, per month	$12.00	(I)
Multi-Family Home Basic Charge, per month	$8.00	
Three Phase Demand Charge, per kW demand	$2.20	
Three Phase Minimum Demand Charge, per month	$3.80	
Distribution Energy Charge, per kWh	4.435¢	(I)
Transmission & Ancillary Services Charge		
Per kWh	0.918¢	(I)
System Usage Charge		
Schedule 200 Related, per kWh	0.066¢	(R)
T&A and Schedule 201 Related, per kWh	0.082¢	(I)

Supply Service Options

All Consumers shall pay the applicable rates under Schedule 200, Base Supply Service. Additionally, each Consumer shall pay the applicable rates under Supply Service Schedule 201.

Franchise Fees

Franchise fees related to Schedule 200, Base Supply Service, are collected through the System Usage Charge - Schedule 200 Related rate. Franchise fees related to Transmission & Ancillary Services and franchise fees related to Schedule 201, Net Power Costs, are collected through the System Usage Charge - T&A and Schedule 201 Related rate. Franchise fees related to distribution charges are collected through distribution charges.

On- and Off-Peak Definitions

On-Peak Period	All days 5 p.m. to 9 p.m.
Off-Peak Period	All other hours

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OUTDOOR AREA LIGHTING SERVICE -
DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To all Consumers for outdoor area lighting service furnished from dusk to dawn by means of Company-owned lamps which may be served by secondary voltage circuits from the Company's existing overhead distribution system. Luminaires shall be mounted on Company-owned wood poles and served in accordance with the Company's specifications as to equipment and installation. Lamp installations on any pole except an existing distribution pole are closed to new service.

Monthly Billing

The Monthly Billing shall be the Rate Per Luminaire plus the applicable adjustments as specified in Schedule 90.

Type of Lamp	LED Equivalent Lumens	Monthly kWh	Rate Per Lamp	
Level 1	0-5,000	19	$7.04	(R)
Level 2	5,001-12,000	34	$8.11	(R)
Level 3	12,001+	57	$9.63	(R)

Supply Service Option

All Consumers shall pay the applicable rates under Schedule 200, Base Supply Service. Supply Service shall be provided by Supply Service Schedule 201.

Franchise Fees

Franchise fees related to Schedule 200, Base Supply Service, Transmission & Ancillary Services, Schedule 201, Net Power Costs, and distribution charges are collected through rates in this schedule.

Special Conditions

1. Inoperable lights will be repaired as soon as reasonably possible, during regular business hours or as allowed by Company’s operating schedule and requirements, provided the Company receives notification of inoperable lights from Consumer or a member of the public by either notifying Pacific Power’s customer service (1-888-221-7070) or www.pacificpower.net/streetlights. Pacific Power’s obligation to repair street lights is limited to this tariff.

2. The Company reserves the right to contract for the maintenance of lighting service provided hereunder.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 23

GENERAL SERVICE - SMALL NONRESIDENTIAL
DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Small Nonresidential Consumers whose entire electric service requirements are supplied hereunder and as specified in the Company's Rules & Regulations, Rule 7.J. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed, except as provided below for Communication Devices. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one-year period will be provided only by special contract for such service.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge, Transmission & Ancillary Services Charge, and the System Usage Charge plus the applicable adjustments as specified in Schedule 90.

Distribution Charge	**Delivery Voltage** Secondary	Primary	
Basic Charge			
Single Phase, per month	$17.35	$17.35	
Three Phase, per month	$25.90	$25.90	
Load Size Charge			
≤ 15 kW	No Charge	No Charge	
> 15 kW, per kW for all kW in excess of 15 kW Load Size	$1.65	$1.65	(I)(I)
Demand Charge, the first 15 kW of demand	No Charge	No Charge	
Demand Charge, for all kW in excess of 15 kW, per kW	$5.51	$5.44	(I)(I)
Distribution Energy Charge, per kWh	4.109¢	4.045¢	(I)(I)
Reactive Power Charge, per kvar	$0.65	$0.60	
Transmission & Ancillary Services Charge			
Per kWh	0.780¢	0.768¢	(I)(I)
System Usage Charge			
Schedule 200 Related, per kWh	0.064¢	0.063¢	(I)(I)
T&A and Schedule 201 Related, per kWh	0.077¢	0.076¢	(I)(I)

kW Load Size

For determination of the Basic Charge and Load Size Charge, the kW load size shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 28

GENERAL SERVICE
LARGE NONRESIDENTIAL 31 KW to 200 KW
DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Large Nonresidential Consumers whose entire electric service requirements are supplied hereunder and whose loads have not registered more than 200 kW, more than six times in the preceding 12-month period and as specified in the Company's Rules & Regulations, Rule 7.J. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one-year period will be provided only by special contract for such service.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge, Transmission & Ancillary Services Charge, and the System Usage Charge plus the applicable adjustments as specified in Schedule 90.

	Delivery Voltage		
	Secondary	**Primary**	
Distribution Charge			
Basic Charge			
Load Size ≤50 kW, per month	$ 19.00	$ 17.00	(R)
Load Size 51-100 kW, per month	$ 34.00	$ 30.00	(R)(R)
Load Size 101 - 300 kW, per month	$ 82.00	$ 70.00	(R)(R)
Load Size > 300 kW, per month	$117.00	$100.00	(R)(R)
Load Size Charge			
≤50 kW, per kW Load Size	$ 1.20	$ 1.00	(R)
51 - 100 kW, per kW Load Size	$ 0.95	$ 0.80	(R)
101 – 300 kW, per kW Load Size	$ 0.55	$ 0.50	(R)
> 300 kW, per kW Load Size	$ 0.35	$ 0.25	(R)
Demand Charge, per kW	$ 3.95	$ 3.42	(R)(R)
Distribution Energy Charge, per kWh	0.395¢	0.034¢	(R)(R)
Reactive Power Charge, per kvar	$ 0.65	$ 0.60	
Transmission & Ancillary Services Charge			
Per kW	$ 2.13	$ 1.67	(R)(R)
System Usage Charge			
Schedule 200 Related, per kWh	0.069¢	0.077¢	(I)(I)
T&A and Schedule 201 Related, per kWh	0.083¢	0.091¢	(I)(I)

kW Load Size:

For determination of the Basic Charge and the Load Size Charge, the kW load size shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

Minimum Charge

The minimum monthly charge shall be the Basic Charge and the Load Size Charge plus the demand charge. A higher minimum may be required under contract to cover special conditions.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 29

PILOT FOR GENERAL SERVICE TIME-OF-USE
DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Nonresidential Consumers whose entire electric service requirements are supplied hereunder and whose loads have not registered more than 1,000 kW, more than three times in the preceding 12-month period or more than 2,000 kW more than once in the preceding 18-month period and who are not otherwise subject to service on Schedules 47 or 48. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. Participation in this schedule will be limited to 100 metered points of delivery on a first-come, first served basis. New customer connections made on or after January 1, 2021 will be exempt from the participation cap and will be allowed to take service under this schedule if otherwise eligible. (T)

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge, Transmission & Ancillary Services Charge and System Usage Charge plus the applicable adjustments as specified in Schedule 90 for Schedule 28.

Distribution Charge		
Basic Charge, per month	$36.00	(R)
Distribution Energy Charge		
First 50 kWh per kW demand, per kWh	18.559¢	(R)
All Additional kWh, per kWh	-1.308¢	(R)
Transmission & Ancillary Services Charge		
Per kWh	0.713¢	(R)
System Usage Charge		
Schedule 200 Related, per kWh	0.069¢	(I)
T&A and Schedule 201 Related, per kWh	0.083¢	(I)

Minimum Charge

The minimum monthly charge shall be the Basic Charge. A higher minimum may be required under contract to cover special conditions.

Demand

The kW shown by or computed from the readings of the Company's demand meter for the 15-minute period of the Consumer's greatest use during the month, determined to the nearest kW, but not less than 15 kW.

Supply Service Options

All Consumers taking Delivery Service under this schedule shall pay the applicable rates in Schedule 200, Base Supply Service. Additionally, each Consumer shall pay the applicable rates in Supply Service Schedule 201.

Franchise Fees

Franchise fees related to Schedule 200, Base Supply Service, are collected through the System Usage Charge - Schedule 200 Related rate. Franchise fees related to Transmission & Ancillary Services and franchise fees related to Schedule 201, Net Power Costs, are collected through the System Usage Charge - T&A and Schedule 201 Related rate. Franchise fees related to distribution charges are collected through distribution charges.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 30

GENERAL SERVICE
LARGE NONRESIDENTIAL 201 KW to 999 KW
DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Large Nonresidential Consumers whose entire electric service requirements are supplied hereunder and whose loads have registered more than 200 kW, more than six times in the preceding 12-month period but have not registered 1,000 kW or more, more than once in the preceding 18-month period and who are not otherwise subject to service on Schedules 47 or 48. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one-year period will be provided only by special contract for such service.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge, Transmission & Ancillary Services Charge, and the System Usage Charge plus the applicable adjustments as specified in Schedule 90.

Distribution Charge	**Delivery Voltage**		
	Secondary	**Primary**	
Basic Charge			
Load Size ≤200 kW, per month	$438.00	$410.00	(R)(R)
Load Size 201 - 300 kW, per month	$128.00	$130.00	(R)(R)
Load Size > 300 kW, per month	$339.00	$338.00	(R)(R)
Load Size Charge			
≤200 kW, per kW Load Size	No Charge	No Charge	
201 – 300 kW, per kW Load Size	$1.55	$1.40	(R)(R)
> 300 kW, per kW Load Size	$0.75	$0.70	(R)(R)
Demand Charge, per kW	$3.72	$3.59	(R)(R)
Reactive Power Charge, per kvar	$0.65	$0.60	
Transmission & Ancillary Services Charge			
Per kW	$2.52	$2.54	(I)
System Usage Charge			
Schedule 200 Related, per kWh	0.068¢	0.069¢	(I)(I)
T&A and Schedule 201 Related, per kWh	0.081¢	0.082¢	(I)(I)

kW Load Size:

For determination of the Basic Charge and the Load Size Charge, the kW load size shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

Minimum Charge

The minimum monthly charge shall be the Basic Charge and the Load Size Charge plus the demand charge. A higher minimum may be required under contract to cover special conditions.

Reactive Power Charge

The maximum 15-minute reactive demand for the month in kilovolt-amperes in excess of 40% of the measured kilowatt demand for the same month.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 41

AGRICULTURAL PUMPING SERVICE
DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Consumers desiring service for agricultural irrigation or agricultural soil drainage pumping installations only and whose loads have not registered 1,000 kW or more, more than once in the preceding 18-month period and who are not otherwise subject to service on Schedule 47 or 48. Service furnished under this Schedule will be metered and billed separately at each point of delivery.

Monthly Billing

Except for November, the monthly billing shall be the sum of the Distribution Energy Charge, Reactive Power Charge, Transmission & Ancillary Services Charge, and the System Usage Charge plus the applicable adjustments as specified in Schedule 90. For November, the billing shall be the sum of the Basic Charge, Load Size Charge, Distribution Energy Charge, Reactive Power Charge, Transmission & Ancillary Services Charge, and the System Usage Charge plus the applicable adjustments as specified in Schedule 90.

Distribution Charge	**Delivery Voltage**		
	Secondary	**Primary**	
Basic Charge (November billing only)			
Load Size ≤ 50 kW, or Single Phase Any Size	No Charge	No Charge	
Three Phase Load Size 51 - 300 kW	$490.00	$480.00	(I)(I)
Three Phase Load Size > 300 kW	$1,930.00	$1,900.00	(I)(I)
Load Size Charge (November billing only)			
Single Phase Any Size, Three Phase ≤ 50 kW, per kW Load Size	$17.10	$16.90	
Three Phase 51 - 300 kW, per kW Load Size	$11.70	$11.50	
Three Phase > 300 kW, per kW Load Size	$7.20	$7.10	
Single Phase, Minimum Charge	$90.00	$90.00	(I)(I)
Three Phase, Minimum Charge	$140.00	$140.00	(I)(I)
Distribution Energy Charge, per kWh	6.140¢	6.045¢	(I)(I)
Reactive Power Charge, per kVar	$0.65	$0.60	
Transmission & Ancillary Services Charge			
Per kWh	0.678¢	0.668¢	(I)(I)
System Usage Charge			
Schedule 200 Related, per kWh	0.067¢	0.066¢	(I)(I)
T&A and Schedule 201 Related, per kWh	0.057¢	0.056¢	(R)(R)

kW Load Size

For determination of the Basic Charge and the Load Size Charge, the kW load size shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

Monthly kW is the measured kW shown by or computed from the readings of the Company's meter, or by appropriate test, for the 15-minute period of the Consumer's greatest takings during the billing month; provided, however, that for motors 10 hp or less, the Monthly kW may, subject to confirmation by test, be determined from the nameplate hp rating and the following table:

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 47

LARGE GENERAL SERVICE
PARTIAL REQUIREMENTS 1,000 KW AND OVER
DELIVERY SERVICE

Available
In all territory served by the Company in the State of Oregon.

Applicable
To Large Nonresidential Consumers supplying all or some portion of their load by self-generation operating on a regular basis, requiring standby electric service from the Company where the Consumer's self-generation has both a total nameplate rating of 1,000 kW or greater and where standby electric service is required for 1,000 kW or greater. Consumers requiring standby electric service from the Company for less than 1,000 kW shall be served under the applicable general service schedule.

If Consumer elects to receive Supply Service from an ESS, Delivery Service shall be provided under Schedule 747, Direct Access Delivery Service.

Monthly Billing
The Monthly Billing shall be the sum of the Distribution Charge, Reserves Charge, Transmission & Ancillary Services Charge, and System Usage Charge plus the applicable adjustments as specified in Schedule 90.

	Delivery Voltage			
Distribution Charge	**Secondary**	**Primary**	**Transmission**	
Basic Charge				
Facility Capacity ≤ 4,000 kW, per month	$540.00	$530.00	$710.00	(R)(R)
Facility Capacity > 4,000 kW, per month	$1,500.00	$1,470.00	$1,820.00	(R)(R)
Facilities Charge				
≤ 4,000 kW, per kW Facility Capacity	$2.95	$1.25	$1.25	(I)(R)
> 4,000 kW, per kW Facility Capacity	$0.80	$0.85	$1.05	
On-Peak Demand Charge, per kW	$3.42	$3.65	$2.04	(R)(R)(R)
Reactive Power Charges				
Per kvar	$0.65	$0.60	$0.55	
Per kVarh	$0.0008	$0.0008	$0.0008	
Reserves Charges				
Spinning Reserves				
Per kW of Facility Capacity	$0.27	$0.27	$0.27	
Spinning Reserves (with Company approved Self-Supply Agreement)				
Per kW of Spinning Reserves Level	($0.27)	($0.27)	($0.27)	
Supplemental Reserves				
Per kW of Facility Capacity	$0.27	$0.27	$0.27	
Supplemental Reserves (with Company-approved Load Reduction Plan or Self-Supply Agreement)				
Per kW of Supplemental Reserves Level	($0.27)	($0.27)	($0.27)	
Transmission & Ancillary Services Charge				
Per kW of On-Peak Demand	$2.23	$2.45	$3.11	(R) (R)
System Usage Charge				
Schedule 200 Related, per kWh	0.068¢	0.065¢	0.062¢	(I)(I)(I)
T&A and Schedule 201 Related, per kWh	0.080¢	0.076¢	0.072¢	(I)(I)(I)

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

Available

In all territory served by the Company in the State of Oregon.

Applicable

This Schedule is applicable to electric service loads which have registered 1,000 kW or more, more than once in a preceding 18-month period. This Schedule will remain applicable until the Consumer fails to meet or exceed 1,000 kW for a subsequent period of 36 consecutive months. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one-year period will be provided only by special contract for such service.

Partial requirements service for loads of 1,000 kW and over will be provided only by application of the provisions of Schedule 47.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge, Transmission & Ancillary Services Charge, and the System Usage Charge plus the applicable adjustments as specified in Schedule 90.

<u>**Distribution Charge**</u>		<u>**Delivery Voltage**</u>		
	Secondary	**Primary**	**Transmission**	
Basic Charge				
Facility Capacity ≤ 4,000 kW, per month	$540.00	$530.00	$710.00	(R)(R)
Facility Capacity > 4,000 kW, per month	$1,500.00	$1,470.00	$1,820.00	(R)(R)
Facilities Charge				
≤ 4,000 kW, per kW Facility Capacity	$2.95	$1.25	$1.25	(I)(R)
> 4,000 kW, per kW Facility Capacity	$0.80	$0.85	$1.05	
On-Peak Demand Charge, per kW	$3.42	$3.65	$2.04	(R)(R)(R)
Reactive Power Charge, per kvar	$0.65	$0.60	$0.55	
<u>**Transmission & Ancillary Services Charge**</u>				
Per kW of On-Peak Demand	$2.77	$2.99	$3.65	(R) (R)
<u>**System Usage Charge**</u>				
Schedule 200 Related, per kWh	0.068¢	0.065¢	0.062¢	(I)(I)(I)
T&A and Schedule 201 Related, per kWh	0.080¢	0.076¢	0.072¢	(I)(I)(I)

Facility Capacity

For determination of the Basic Charge and the Facilities Charge, the Facility Capacity shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

Minimum Charge

The minimum monthly charge shall be the Basic Charge and the Facilities Charge. A higher minimum may be required by contract.

Reactive Power Charge

The maximum 15-minute reactive demand for the month in kilovolt-amperes in excess of 40% of the maximum measured kilowatt demand for the same month.

(continued)

Available

In all territory served by the Company in the State of Oregon.

Applicable

To unmetered lighting service provided to municipalities or agencies of municipal, county, state or federal governments for dusk to dawn illumination of public streets, highways and thoroughfares by means of Company owned, operated and maintained street lighting systems controlled by a photoelectric control or time switch.

Monthly Billing

The Monthly Billing shall be the rate per luminaire as specified in the rate tables below plus the applicable adjustments as specified in Schedule 90.

Type of Lamp	Level 1	Level 2	Level 3	Level 4	Level 5	Level 6	
LED Equivalent Lumens	0-3,500	3,501-5,500	5,501-8,000	8,001-12,000	12,001-15,500	15,501+	
Monthly kWh	8	15	25	34	44	57	
Functional Lighting	$ 5.81	$ 6.17	$ 6.31	$ 6.43	$ 6.85	$ 8.35	(R)
Functional Lighting - Customer Funded Conversion	$ 3.14	$ 3.33	$ 3.46	$ 3.54	$ 3.80	$ 4.65	(R)
Decorative Series	N/A	$ 10.62	$ 10.73	N/A	N/A	N/A	(R)

Functional Lighting: Common less expensive luminaires that may be mounted either on wood, fiberglass or non-decorative metal poles. The Company will maintain a list of functional light fixtures that are available.

Customer-Funded Conversion: Street lights that have been converted to LED from another lighting type and whose conversion was funded by the Customer.

Decorative Series Lighting: More stylish luminaires mounted vertically on decorative metal poles. The Company will maintain a listing of standard decorative street light fixtures that are available under this Schedule.

Supply Service Options

All Consumers taking Delivery Service under this schedule shall pay the applicable rates in Schedule 200, Base Supply Service. Additionally, each Consumer shall specify Supply Service Schedule 201 or Schedule 220, as appropriate and in accordance with the Applicable section of the specified rate schedule. If Consumer elects to receive Supply Service from an ESS, Delivery Service shall be provided under Schedule 751, Direct Access Delivery Service.

Franchise Fees

Franchise fees related to Schedule 200, Base Supply Service, Transmission & Ancillary Services, Schedule 201, Net Power Costs, and distribution charges are collected through rates in this schedule.

(continued)

Available

In all territory served by the Company in the State of Oregon.

Applicable

To lighting service provided to municipalities or agencies of municipal, county, state or federal governments for dusk to dawn illumination of public streets, highways and thoroughfares by means of Consumer owned street lighting systems controlled by a photoelectric control or time switch.

Monthly Billing

Energy Only Service - Rate per Luminaire

Energy Only Service includes energy supplied from Company's overhead or underground circuits and does not include any maintenance to Consumer's facilities. Maintenance service will be provided only as indicated in the Maintenance Service section below.

The Monthly Billing shall be the rate per luminaire specified in the rate tables below plus the applicable adjustments as specified in Schedule 90.

High Pressure Sodium Vapor						
Lumen Rating	5,800	9,500	16,000	22,000	27,500	50,000
Watts	70	100	150	200	250	400
Monthly kWh	31	44	64	85	115	176
Energy Only Service	$ 1.18	$ 1.67	$ 2.43	$ 3.23	$ 4.37	$ 6.69

(R)

Metal Halide					
Lumen Rating	9,000	12,000	19,500	32,000	107,800
Watts	100	175	250	400	1,000
Monthly kWh	39	68	94	149	354
Energy Only Service	$ 1.48	$ 2.58	$ 3.57	$ 5.66	$ 13.45

(R)

For non-listed luminaires the cost will be calculated for 4167 annual hours of operation including applicable loss factors for ballasts and starting aids at the cost per kWh given below.

Non-Listed Luminaire	¢/kWh
Energy Only Service	3.799

(R)

Maintenance Service (No New Service)

Where the utility operates and maintains the system, a flat rate equal to one-twelfth the estimated annual cost for operation and maintenance will be added to the Energy Only Service rates listed above. Monthly Maintenance is only applicable for existing monthly maintenance service agreements in effect prior to May 24, 2006.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

RECREATIONAL FIELD LIGHTING - RESTRICTED DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To schools, governmental agencies and nonprofit organizations for service supplied through one meter at one point of delivery and used exclusively for annually recurring seasonal lighting of outdoor athletic or recreational fields. This Schedule is not applicable to any enterprise which is operated for profit. Service for purposes other than recreational field lighting may not be combined with such field lighting for billing purposes under this Schedule. At the Consumer's option, service for recreational field lighting may be taken under the Company's applicable General Service Schedule.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge, Transmission & Ancillary Services Charge, and the System Usage Charge plus the applicable adjustments as specified in Schedule 90.

Distribution Charge		
Basic Charge, Single Phase, per month	$ 6.00	
Basic Charge, Three Phase, per month	$ 9.00	
Distribution Energy Charge, per kWh	4.090¢	(R)
Transmission & Ancillary Services Charge		
per kWh	0.037¢	(R)
System Usage Charge		
Schedule 200 Related, per kWh	0.018¢	(R)
T&A and Schedule 201 Related, per kWh	0.018¢	

Minimum Charge

The minimum monthly charge shall be the Basic Charge.

Supply Service Options

All Consumers taking Delivery Service under this schedule shall pay the applicable rates in Schedule 200, Base Supply Service. Additionally, each Consumer shall specify Supply Service Schedule 201 or Schedule 220, as appropriate and in accordance with the Applicable section of the specified rate schedule. If Consumer elects to receive Supply Service from an ESS, Delivery Service shall be provided under Schedule 754, Direct Access Delivery Service.

Franchise Fees

Franchise fees related to Schedule 200, Base Supply Service, are collected through the System Usage Charge - Schedule 200 Related rate. Franchise fees related to Transmission & Ancillary Services and franchise fees related to Schedule 201, Net Power Costs, are collected through the System Usage Charge - T&A and Schedule 201 Related rate. Franchise fees related to distribution charges are collected through distribution charges.

Special Conditions

The Consumer shall own all poles, wire and other distribution facilities beyond the Company's point of delivery.

Continuing Service

This Schedule is based on continuing service at each service location. Disconnect and reconnect transactions shall not operate to relieve a Consumer from monthly minimum charges.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 76R

LARGE GENERAL SERVICE - PARTIAL REQUIREMENTS SERVICE
ECONOMIC REPLACEMENT POWER RIDER
DELIVERY SERVICE

Purpose

To provide Consumers served on Schedule 47 with the opportunity of purchasing Energy from the Company to replace some or all of the Consumer's on-site generation when the Consumer deems it is more economically beneficial than self generating.

Available

In all territory served by the Company in Oregon. The Company may limit service to a Consumer if system reliability would be affected. The Company has no obligation to provide the Consumer with economic replacement power except as explicitly agreed to between Company and Consumer.

Applicable

To Large Nonresidential Consumers receiving Delivery Service under Schedule 47.

Character of Service

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

Monthly Billing

The following charges are in addition to applicable charges under Schedule 47 plus the applicable adjustments as specified in Schedule 90:

	Delivery Voltage			
	Secondary	**Primary**	**Transmission**	
Transmission & Ancillary Services Charge				
Per kW of Daily Economic Replacement Power (ERP) On-Peak Demand per day	$0.087	$0.095	$0.121	(R)
Daily ERP Demand Charge				
Per kW of Daily ERP On-Peak Demand	$0.133	$0.142	$0.079	(R)(R)(R)

Supply Service

A Consumer taking Delivery Service under this Schedule shall be served under the terms of Supply Service Schedule 276R.

ERP and ENF

Economic Replacement Power (ERP) is Electricity supplied by the Company to meet an Energy Needs Forecast (ENF) pursuant to an Economic Replacement Power Agreement (ERPA). ERP, ENF and ERPA are more fully described in Schedule 276R.

Daily ERP On-Peak Demand

Daily ERP On-Peak Demand shall not be less than the maximum ERP On-Peak Demand scheduled per day and shall not be greater than the difference between the Facility Capacity and the Baseline Demand. Daily ERP On-Peak Demand will be billed for each day in the month that the Company supplies ERP to the Consumer.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 90

SUMMARY OF EFFECTIVE RATE ADJUSTMENTS

The following summarizes the applicability of the Company's adjustment schedules

SUMMARY OF EFFECTIVE RATE ADJUSTMENTS

(D)

Schedule	91	93	94	96	97	98*	194	195	198	202*	203*	204
4	x	x	x	x	x	x	x	x	x	x	x	x
5	x	x	x	x	x	x	x	x	x	x	x	x
15	x	x	x	x		x	x	x	x	x	x	x
23	x	x	x	x		x	x	x	x	x	x	x
28	x	x	x	x		x	x	x	x	x	x	x
30	x	x	x	x		x	x	x	x	x	x	x
41	x	x	x	x	x	x	x	x	x	x	x	x
47	x	x	x	x	x	x	x	x	x	x	x	x
48	x	x	x	x	x	x	x	x	x	x	x	x
51	x	x	x	x			x	x	x	x	x	x
53	x	x	x	x			x	x	x	x	x	x
54	x	x	x	x			x	x	x	x	x	x
60												
723	x	x	x	x		x	x	x	x	x	x	x
728	x	x	x	x		x	x	x	x	x	x	x
730	x	x	x	x		x	x	x	x	x	x	x
741	x	x	x	x	x	x	x	x	x	x	x	x
747	x	x	x	x	x	x	x	x	x	x	x	x
748	x	x	x	x	x	x	x	x	x	x	x	x
751	x	x	x	x			x	x	x	x	x	x
753	x	x	x	x			x	x	x	x	x	x
754	x	x	x	x			x	x	x	x	x	x
848	x		x									

(D)

*Not applicable to all consumers. See Schedule for details.

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 98

ADJUSTMENT ASSOCIATED WITH THE PACIFIC NORTHWEST
ELECTRIC POWER PLANNING AND CONSERVATION ACT

All bills to qualifying residential and nonresidential customers shall have deducted an amount equal to the product of all kilowatt-hours of use multiplied by the following cents per kilowatt-hour: (D) (C)

0.914¢ per kWh

Condition of Service

The eligibility of affected Customers for the rate credit specified in this tariff is as provided by the Pacific Northwest electric Power Planning and Conservation Act, Public Law 96-501.

Eligible Customers with usage at or above 100,000 kWh per year must complete and submit to the Company a certificate verifying eligibility in order to receive the rate credit. Certificate forms are available on the Company's website at www.pacificpower.net under Oregon Regulatory Information. Consistent with the requirements of the Bonneville Power Administration, a federal agency, customers using electricity to aid in growing one or more Cannabis plants are not eligible for the rate credit specified in this tariff. If, in the course of doing business, a utility discovers that one of its existing customers is not eligible for the rate credit specified in this tariff, the customer will no longer receive the credit.

Special Conditions

In no instance shall a farm's total qualifying irrigation load for any billing period exceed 222,000 kWh. Under the Northwest Power Act, any farm may receive REP benefits for up to a maximum of 400 horsepower (HP)/month (222,000 kWh/month) of qualified irrigation/pumping load (the "REP Benefits Qualified Irrigation/Pumping Load Cap" or "Irrigation/Pumping Load Cap").

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 104

OREGON CORPORATE ACTIVITY TAX
RECOVERY ADJUSTMENT

Purpose

To recover from Consumers in the State of Oregon the Oregon Corporate Activity Tax (OCAT) paid by the Company in accordance with HB 3427-A.

Applicable

To all bills for all Consumers whose electric service requirements are supplied by the Company in the State of Oregon.

Balancing Account

A balancing account will be maintained to accrue any difference between the Company's actual OCAT expense and the amount collected from Consumers through this adjustment rate. Any over- or under-collection of the OCAT expense will be considered when the OCAT Rate is periodically reviewed.

Oregon Corporate Activity Tax Recovery Adjustment Rate

The adjustment rate is:

0.54% of the total billed amount to the Consumer excluding the Low Income Bill Payment Assistance Fund (Schedule 91), the Adjustment Associated with the Pacific Northwest Power Planning and Conservation Act (Schedule 98), the Public Purpose Charge (Schedule 290), the Energy Conservation Charge (Schedule 297) and separately stated state and local taxes.

The adjustment rate will be reviewed periodically and updated as necessary to collect the expected OCAT expense and to correct any over- or under-collection in the OCAT balancing account.

Issued March 8, 2021
Etta Lockey, Vice President, Regulation
Effective for service on and after April 21, 2021
Advice No. 21-006

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 200

BASE SUPPLY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To all Residential Consumers and Nonresidential Consumers. This service may be taken only in conjunction with the applicable Delivery Service Schedule or Direct Access Delivery Service Schedule. Not applicable to energy usage under Delivery Service Schedule 76 which is billed at Economic Replacement Power rates under Schedule 276 or energy usage under Delivery Service Schedule 47 which is billed at Unscheduled Energy rates under Schedule 247.

Monthly Billing

The Monthly Billing shall be the Energy Charge and/or Demand Charge, as specified below by Delivery Service Schedule.

Delivery Service Schedule No.		**Delivery Voltage**			
		Secondary	**Primary**	**Transmission**	(D)
4	Per Summer kWh	3.648¢			(N)
	Per Winter kWh	2.698¢			(N)
					(D)
5	Per Summer kWh	3.648¢			(N)
	Per Winter kWh	2.698¢			(N)
					(D)
6	Per Summer kWh	3.648¢			(N)
	Per Winter kWh	2.698¢			(N)

For Schedules 4, 5 and 6, Summer is defined as months of June through September. (N)
Winter is defined as the months of October through May. Seasonal kilowatt-hours (N)
shall be prorated to the nearest whole kilowatt-hour based upon the number of whole (N)
days in the billing period falling within each season. (N)

23, 723	First 3,000 kWh, per kWh	2.957¢	2.911¢		(I)(I)
	All additional kWh, per kWh	2.195¢	2.161¢		(I)(I)
28, 728	All kWh, per kWh	2.757¢	2.693¢		(I)(R)

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 200

Monthly Billing (continued)

Delivery Service Schedule No.		**Delivery Voltage**			
		Secondary	**Primary**	**Transmission**	
29	All kWh, per kWh	2.757¢	2.757¢		(I)(I)
30, 730	Demand Charge, per kW	$5.80	$5.80		(I)(I)
	All kWh, per kWh	1.073¢	1.037¢		(R)(R)
	Demand shall be as defined in the Delivery Service Schedule				
41, 741	All kWh	2.666¢	2.625¢		(I)(I)
47/48, 747/748	Demand Charge, per kW of On-Peak Demand	$1.66	$1.74	$1.77	(I)(I)(I)
	Per kWh, On-Peak	2.266¢	2.216¢	2.190¢	(I)(I)(I)
	Per kWh, Off-Peak	2.266¢	2.216¢	2.190¢	(I)(I)(I)

Summer On-Peak hours are from 1 p.m. to 10 p.m. all days in the Summer months of June through September. Non-Summer On-Peak hours are from 6 a.m. to 9 a.m. and 4 p.m. to 10 p.m. in the Non-Summer months of October through May. All remaining hours are Off-Peak.
On-Peak Demand shall be as defined in the Delivery Service Schedule.

15	**Type of Lamp**	**LED Equivalent Lumens**	**Monthly kWh**	**Rate Per Lamp**	
	Level 1	0-5,500	19	$0.73	(R)
	Level 2	5,501-12,000	34	$1.32	(R)
	Level 3	12-001+	57	$2.21	(R)

(continued)

Monthly Billing (continued)

Delivery Service Schedule No.

Schedule	Type of Lamp	LED Equivalent Lumens	Monthly kWh	Rate per Lamp	
51, 751	Level 1	0-3,500	8	$0.30	(R)
	Level 2	3,501-5,500	15	$0.57	
	Level 3	5,501-8,000	25	$0.94	
	Level 4	8,001-12,000	34	$1.27	
	Level 5	12,001-15,500	44	$1.65	
	Level 6	15,501+	57	$2.14	(R)

Schedule	Types of Luminaire	Nominal rating	Watts	Monthly kWh	Rate Per Luminaire	
53, 753	High Pressure Sodium	5,800	70	31	$0.15	(R)
	High Pressure Sodium	9,500	100	44	$0.21	
	High Pressure Sodium	16,000	150	64	$0.30	
	High Pressure Sodium	22,000	200	85	$0.40	
	High Pressure Sodium	27,500	250	115	$0.54	
	High Pressure Sodium	50,000	400	176	$0.83	
	Metal Halide	9,000	100	39	$0.18	
	Metal Halide	12,000	175	68	$0.32	
	Metal Halide	19,500	250	94	$0.44	
	Metal Halide	32,000	400	149	$0.70	
	Metal Halide	107,800	1,000	354	$1.67	
	Non-Listed Luminaire, per kWh				0.473¢	
54, 754	Per kWh			0.610¢		(R)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 205

TAM ADJUSTMENT FOR OTHER REVENUES

Purpose
This schedule adjusts rates for Other Revenues as authorized by Order No. 10-363.

Applicable
To all Residential Consumers and Nonresidential Consumers.

Energy Charge
The adjustment rate is listed below by Delivery Service Schedule and Direct Access Delivery Service Schedule.

Delivery Service Schedule No.			**Delivery Voltage**			
			Secondary	**Primary**	**Transmission**	
4	Per kWh	0-1000 kWh	0.000¢			(R)
		> 1000 kWh	0.000¢			(R)
5	Per kWh	0-1000 kWh	0.000¢			(R)
		> 1000 kWh	0.000¢			(R)

For Schedules 4 and 5, the kilowatt-hour blocks listed above are based on an average month of approximately 30.42 days. Residential kilowatt-hour blocks shall be prorated to the nearest whole kilowatt-hour based upon the number of whole days in the billing period (see Rule 10 for details).

6	Per kWh	All kWh	0.000¢			(R)
23, 723	First 3,000 kWh, per kWh		0.000¢	0.000¢		(R)
	All additional kWh, per kWh		0.000¢	0.000¢		(R)
28, 728	All kWh, per kWh		0.000¢	0.000¢		(R)

(continued)

Energy Charge (continued)

Delivery Service Schedule No.		**Delivery Voltage** Secondary	Primary	Transmission	
29	All kWh, per kWh	0.000¢	0.000¢		(R)
30, 730	All kWh, per kWh	0.000¢	0.000¢		(R)
41, 741	All kWh, per kWh	0.000¢	0.000¢		(R)
47/48	Per kWh On-Peak	0.000¢	0.000¢	0.000¢	(R)
747/748	Per kWh, Off-Peak	0.000¢	0.000¢	0.000¢	(R)

For Schedule 47 and Schedule 48, Summer On-Peak hours are from 1 p.m. to 10 p.m. all days in the Summer months of June through September. Non-Summer On-Peak hours are from 6 a.m. to 9 a.m. and 4 p.m. to 10 p.m. in the Non-Summer months of October through May. Off-Peak hours are all remaining hours.

	Type of Lamp	**LED Equivalent Lumens**	**Monthly kWh**	**Rate per Lamp**	
15	Level 1	0-5,000	19	$0.00	(R)
	Level 2	5,001-12,000	34	$0.00	(R)
	Level 3	12,001+	57	$0.00	(R)

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

Energy Charge (continued)

Delivery Service Schedule No.

	Type of Lamp	LED Equivalent Lumens	Monthly kWh	Rate per Lamp	
51, 751	Level 1	0-3,500	8	$0.00	
	Level 2	3,501-5,500	15	$0.00	
	Level 3	5,501-8,000	25	$0.00	(R)
	Level 4	8,001-12,000	34	$0.00	(R)
	Level 5	12,001-15,500	44	$0.00	(R)
	Level 6	15,501+	57	$0.00	(R)

	Types of Luminaire	Nominal rating	Watts	Monthly kWh	Rate Per Luminaire	
53, 753	High Pressure Sodium	5,800	70	31	$0.00	
	High Pressure Sodium	9,500	100	44	$0.00	
	High Pressure Sodium	16,000	150	64	$0.00	(R)
	High Pressure Sodium	22,000	200	85	$0.00	(R)
	High Pressure Sodium	27,500	250	115	$0.00	(R)
	High Pressure Sodium	50,000	400	176	$0.00	(R)
	Metal Halide	9,000	100	39	$0.00	
	Metal Halide	12,000	175	68	$0.00	(R)
	Metal Halide	19,500	250	94	$0.00	(R)
	Metal Halide	32,000	400	149	$0.00	(R)
	Metal Halide	107,800	1,000	354	$0.00	(R)
	Non-Listed Luminaire, per kWh				0.000¢	(R)

(R)

54, 754 Per kWh 0.000¢

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Residential and Small Nonresidential Consumers receiving Delivery Service under Schedules 4, 5, 23 or 41, in conjunction with Supply Service Schedule 201, who have elected to take this service.

Monthly Billing

The Monthly Billing shall be the Energy Charge. The Monthly Billing is in addition to all other charges contained in Consumer's applicable Delivery Service schedule, Base Supply Service Schedule 200 and Supply Service Schedule 201. (C)

(D)

Energy Charge

Delivery Service Schedule No.		Season Winter	Season Summer
4	On-Peak kWh, per kWh	3.316 ¢	6.124 ¢
	Off-Peak kWh, per kWh	(1.125)¢	(1.125)¢
5	On-Peak kWh, per kWh	3.316 ¢	6.124 ¢
	Off-Peak kWh, per kWh	(1.125)¢	(1.125)¢
23	On-Peak kWh, per kWh	4.365 ¢	9.350 ¢
	Off-Peak kWh, per kWh	(1.438)¢	(1.438)¢
41	On-Peak kWh, per kWh	3.737 ¢	8.004 ¢
	Off-Peak kWh, per kWh	(1.231)¢	(1.231)¢

Seasonal Definition

Winter months are defined as October 1 through May 31. Summer months are defined as June (C)
1 through September 30. (C)

(D)

On-Peak Period

Winter
Monday through Friday 6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 8:00 p.m.
Summer
Monday through Friday 4:00 p.m. to 8:00 p.m.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 299

RATE MITIGATION ADJUSTMENT

All bills calculated in accordance with Schedules contained in presently effective Tariff Or. No. 36 shall have applied an amount equal to the product of all metered kilowatt-hours multiplied by the following cents per kilowatt hour.

	Secondary	Primary	Transmission	
Schedule 4	(0.208¢)			(C)
Schedule 5	(0.208¢)			
Schedule 15	8.840¢			
Schedule 23, 723	0.000¢	0.000¢		
Schedule 28, 728	0.495¢	0.495¢		
Schedule 30, 730	0.502¢	0.502¢		
Schedule 41, 741	(2.237¢)	(2.237¢)		
Schedule 47, 747	0.000¢	0.000¢	0.000¢	
Schedule 48, 748	0.000¢	0.000¢	0.000¢	
Schedule 51, 751	9.686¢			
Schedule 53, 753	2.447¢			
Schedule 54, 754	3.135¢			(C)

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Small Nonresidential Consumers who have chosen to receive electricity from an ESS, and as specified in the Company's Rules & Regulations, Rule 7.J. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed, except as provided below for Communication Devices. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one year period will be provided only by special contract for such service.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge and the System Usage Charge plus the applicable adjustments as specified in Schedule 90.

Distribution Charge	**Delivery Voltage**		
	Secondary	**Primary**	
Basic Charge			
Single Phase, per month	$17.35	$17.35	
Three Phase, per month	$25.90	$25.90	
Load Size Charge			
≤ 15 kW	No Charge	No Charge	
> 15 kW, per kW for all kW in excess of 15 kW, Load Size	$ 1.65	$ 1.65	(I)(I)
Demand Charge, the first 15 kW of demand	No Charge	No Charge	
Demand Charge, for all kW in excess of 15 kW, per kW	$ 5.51	$ 5.44	(I)(I)
Distribution Energy Charge, per kWh	4.109¢	4.045¢	(I)(I)
Reactive Power Charge, per kvar	$ 0.65	$ 0.60	
System Usage Charge			
Schedule 200 Related, per kWh	0.064¢	0.063¢	(I)(I)

kW Load Size

For determination of the Basic Charge and the Load Size Charge, the kW load size shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

Minimum Charge

The minimum monthly charge shall be the Basic Charge and the Load Size Charge. A higher minimum may be required under contract to cover special conditions.

Reactive Power Charge

The maximum 15-minute reactive demand for the month in kilovolt-amperes in excess of 40% of the measured kilowatt demand for the same month.

Demand

The kW shown by or computed from the readings of Company's demand meter for the 15-minute period of Consumer's greatest use during the month, determined to the nearest kW.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 728

GENERAL SERVICE
LARGE NONRESIDENTIAL 31 KW TO 200 KW
DIRECT ACCESS DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Large Nonresidential Consumers who have chosen to receive electricity from an ESS, and whose loads have not registered more than 200 kW, more than six times in the preceding 12-month period and as specified in the Company's Rules & Regulations, Rule 7.J. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one year period will be provided only by special contract for such service.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge and the System Usage Charge plus the applicable adjustments as specified in Schedule 90.

Distribution Charge	**Delivery Voltage**		
	Secondary	**Primary**	
Basic Charge			
Load Size ≤ 50 kW, per month	$ 19.00	$ 17.00	(R)
Load Size 51-100 kW, per month	$ 34.00	$ 30.00	(R)(R)
Load Size 101 - 300 kW, per month	$ 82.00	$ 70.00	(R)(R)
Load Size > 300 kW, per month	$117.00	$100.00	(R)(R)
Load Size Charge			
≤ 50 kW, per kW Load Size	$ 1.20	$ 1.00	(R)
51-100 kW, per kW Load Size	$ 0.95	$ 0.80	(R)
101 – 300 kW, per kW Load Size	$ 0.55	$ 0.50	(R)
> 300 kW, per kW Load Size	$ 0.35	$ 0.25	(R)
Demand Charge, per kW	$ 3.95	$ 3.42	(R)(R)
Distribution Energy Charge, per kWh	0.395¢	0.034¢	(R)(R)
Reactive Power Charge, per kvar	$ 0.65	$ 0.60	
System Usage Charge			
Schedule 200 Related, per kWh	0.069¢	0.077¢	(I)(I)

kW Load Size

For determination of the Basic Charge and the Load Size Charge, the kW load size shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

Minimum Charge

The minimum monthly charge shall be the Basic Charge and the Load Size Charge plus the Demand charge. A higher minimum may be required under contract to cover special conditions.

Reactive Power Charge

The maximum 15-minute reactive demand for the month in kilovolt-amperes in excess of 40% of the measured kilowatt demand for the same month.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 730

GENERAL SERVICE
LARGE NONRESIDENTIAL 201 KW TO 999 KW
DIRECT ACCESS DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Large Nonresidential Consumers who have chosen to receive electricity from an ESS, and whose loads have registered more than 200 kW, more than six times in the preceding 12-month period but have not registered 1,000 kW or more, more than once in the preceding 18-month period and who are not otherwise subject to service on Schedule 747 or 748. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one year period will be provided only by special contract for such service.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge and the System Usage Charge plus the applicable adjustments as specified in Schedule 90.

Distribution Charge	**Delivery Voltage** Secondary	Primary	
Basic Charge			
Load Size ≤ 200 kW, per month	$438.00	$410.00	(R)(R)
Load Size 201 - 300 kW, per month	$128.00	$130.00	(R)(R)
Load Size > 300 kW, per month	$339.00	$338.00	(R)(R)
Load Size Charge			
≤ 200 kW, per kW Load Size	No Charge	No Charge	
201 – 300 kW, per kW Load Size	$ 1.55	$ 1.40	(R)(R)
> 300 kW, per kW Load Size	$ 0.75	$ 0.70	(R)(R)
Demand Charge, per kW	$ 3.72	$ 3.59	(R)(R)
Reactive Power Charge, per kvar	$ 0.65	$ 0.60	
System Usage Charge			
Schedule 200 Related, per kWh	0.068¢	0.069¢	(I)(I)

kW Load Size

For determination of the Basic Charge and the Load Size Charge, the kW load size shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

Minimum Charge

The minimum monthly charge shall be the Basic Charge and the Load Size Charge plus the Demand charge. A higher minimum may be required under contract to cover special conditions.

Reactive Power Charge

The maximum 15-minute reactive demand for the month in kilovolt-amperes in excess of 40% of the measured kilowatt demand for the same month.

Demand

The kW shown by or computed from the readings of Company's demand meter for the 15-minute period of Consumer's greatest use during the month, determined to the nearest kW, but not less than 100 kW.

(continued)

AGRICULTURAL PUMPING SERVICE
DIRECT ACCESS DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Consumers who have chosen to receive electricity from an ESS and desiring service for agricultural irrigation or agricultural soil drainage pumping installations only and whose loads have not registered 1,000 kW or more, more than once in the preceding 18-month period and who are not otherwise subject to service on Schedule 747 or 748. Service furnished under this Schedule will be metered and billed separately at each point of delivery.

Monthly Billing

Except for November, the Monthly Billing shall be the sum of the Distribution Energy Charge, Reactive Power Charge, and the System Usage Charge plus the applicable adjustments as specified in Schedule 90. For November, the billing shall be the sum of the Basic Charge, Load Size Charge, Distribution Energy Charge, Reactive Power Charge, and the System Usage Charge plus the applicable adjustments as specified in Schedule 90.

Distribution Charge	**Delivery Voltage**		
Basic Charge (November billing only)	**Secondary**	**Primary**	
Load Size ≤ 50 kW, or Single Phase Any Size	No Charge	No Charge	
Three Phase Load Size 51 - 300 kW	$ 490.00	$ 480.00	(I)(I)
Three Phase Load Size > 300 kW	$1,930.00	$1,900.00	(I)(I)
Load Size Charge (November billing only)			
Single Phase Any Size, Three Phase ≤ 50 kW, per kW Load Size	$ 17.10	$ 16.90	
Three Phase 51 - 300 kW, per kW Load Size	$ 11.70	$ 11.50	
Three Phase > 300 kW, per kW Load Size	$ 7.20	$ 7.10	
Single Phase, Minimum Charge	$ 90.00	$ 90.00	(I)(I)
Three Phase, Minimum Charge	$ 140.00	$ 140.00	(I)(I)
Distribution Energy Charge, per kWh	6.140¢	6.045¢	(I)(I)
Reactive Power Charge, per kVar	$ 0.65	$ 0.60	
System Usage Charge			
Schedule 200 Related, per kWh	0.067¢	0.066¢	(I)(I)

kW Load Size

For determination of the Basic Charge and the Load Size Charge, the kW load size shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

Monthly kW is the measured kW shown by or computed from the readings of Company's meter, or by appropriate test, for the 15-minute period of Consumer's greatest takings during the billing month; provided, however, that for motors 10 hp or less, the Monthly kW may, subject to confirmation by test, be determined from the nameplate hp rating and the following table:

If Motor Size Is:	Monthly kW is:
2 hp or less	2 kW
Over 2 through 3 hp	3 kW
Over 3 through 5 hp	5 kW
Over 5 through 7.5 hp	7 kW
Over 7.5 through 10 hp	9 kW

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 747

LARGE GENERAL SERVICE
PARTIAL REQUIREMENTS 1,000 KW AND OVER
DIRECT ACCESS DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

This Schedule is applicable to Consumers who have chosen to receive electricity from an ESS. To Large Nonresidential Consumers supplying all or some portion of their load by self-generation operating on a regular basis, requiring standby electric service from the Company where the Consumer's self-generation has both a total nameplate rating of 1,000 kW or greater and where standby electric service is required for 1,000 kW or greater. Consumers requiring standby electric service from the Company for less than 1,000 kW shall be served under the applicable general service schedule.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge, Reserves Charges, and the System Usage Charge plus the applicable adjustments as specified in Schedule 90.

	Delivery Voltage			
Distribution Charge	**Secondary**	**Primary**	**Transmission**	
Basic Charge				
Facility Capacity ≤ 4,000 kW, per month	$540.00	$530.00	$710.00	(R)(R)
Facility Capacity > 4,000 kW, per month	$1,500.00	$1,470.00	$1,820.00	(R)(R)
Facilities Charge				
≤ 4,000 kW, per kW Facility Capacity	$2.95	$1.25	$1.25	(I)(R)
> 4,000 kW, per kW Facility Capacity	$0.80	$0.85	$1.05	
On-Peak Demand Charge, per kW	$3.42	$3.65	$2.04	(R)(R)(R)
Reactive Power Charges				
Per kVar	$0.65	$0.60	$0.55	
Per kVarh	$0.0008	$0.0008	$0.0008	
Reserves Charges				
Spinning Reserves				
per kW of Facility Capacity	$0.27	$0.27	$0.27	
Spinning Reserves (with Company-approved Self-Supply Agreement)				
per kW of Self-Supplied Spinning Reserves	($0.27)	($0.27)	($0.27)	
Supplemental Reserves				
per kW of Facility Capacity	$0.27	$0.27	$0.27	
Supplemental Reserves (with Company-approved load reduction plan or Self-Supply Agreement)				
per kW of approved load reduction kW	($0.27)	($0.27)	($0.27)	
System Usage Charge				
Schedule 200 Related, per kWh	0.068¢	0.065¢	0.062¢	(I)(I)(I)

(continued)

Available

In all territory served by the Company in the State of Oregon.

Applicable

This Schedule is applicable to Consumers who have chosen to receive electricity from an ESS, to electric service loads which have registered 1,000 kW or more, more than once in a preceding 18-month period. This Schedule will remain applicable until Consumer fails to meet or exceed 1,000 kW for a subsequent period of 36 consecutive months. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one-year period will be provided only by special contract for such service.

Partial requirements service for loads of 1,000 kW and over will be provided only by application of the provisions of Schedule 747.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge and the System Usage Charge plus the applicable adjustments as specified in Schedule 90.

Distribution Charge	Delivery Voltage			
	Secondary	**Primary**	**Transmission**	
Basic Charge				
Facility Capacity ≤ 4000 kW, per month	$540.00	$530.00	$710.00	(R)
Facility Capacity > 4000 kW, per month	$1,500.00	$1,470.00	$1,820.00	(R)
Facilities Charge				
≤ 4000 kW, per kW Facility Capacity	$2.95	$1.25	$1.25	(I)(R)
> 4000 kW, per kW Facility Capacity	$0.80	$0.85	$1.05	
On-Peak Demand Charge, per kW	$3.42	$3.65	$2.04	(R)(R)(R)
Reactive Power Charge, per kvar	$0.65	$0.60	$0.55	
System Usage Charge				
Schedule 200 Related, per kWh	0.068¢	0.065¢	0.062¢	(I)(I)(I)

Facility Capacity

For determination of the Basic Charge and the Facilities Charge, the Facility Capacity shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

Minimum Charge

The minimum monthly charge shall be the Basic Charge and the Facilities Charge. A higher minimum may be required by contract.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 751

STREET LIGHTING SERVICE COMPANY-OWNED SYSTEM
DIRECT ACCESS DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

This Schedule is applicable to Consumers who have chosen to receive electricity from an ESS. To unmetered lighting service provided to municipalities or agencies of municipal, county, state or federal governments for dusk to dawn illumination of public streets, highways and thoroughfares by means of Company owned, operated and maintained street lighting systems controlled by a photoelectric control or time switch.

Monthly Billing

The Monthly Billing shall be the rate per luminaire as specified in the rate tables below plus the applicable adjustments as specified in Schedule 90.

Type of Lamp	Level 1	Level 2	Level 3	Level 4	Level 5	Level 6	
LED Equivalent Lumens	0-3,500	3,501-5,500	5,501-8,000	8,001-12,000	12,001-15,500	15,501+	
Monthly kWh	8	15	25	34	44	57	
Functional Lighting	$ 5.78	$ 6.12	$ 6.22	$ 6.31	$ 6.70	$ 8.16	(R)
Functional Lighting - Customer Funded Conversion	$ 3.11	$ 3.28	$ 3.37	$ 3.42	$ 3.65	$ 4.46	(R)
Decorative Series	N/A	$ 10.57	$ 10.64	N/A	N/A	N/A	(R)

Functional Lighting: Common less expensive luminaires that may be mounted either on wood, fiberglass or non-decorative metal poles. The Company will maintain a list of functional light fixtures that are available.

Customer-Funded Conversion: Street lights that have been converted to LED from another lighting type and whose conversion was funded by the Customer.

Decorative Series Lighting: More stylish luminaires mounted vertically on decorative metal poles. The Company will maintain a listing of standard decorative street light fixtures that are available under this Schedule.

Base Supply Service

All Consumers taking Delivery Service under this schedule shall pay the applicable rates in Schedule 200, Base Supply Service.

Transmission & Ancillary Services

Consumers taking service under this Schedule must also take service under the Company's FERC Open Access Transmission Tariff (OATT) or be served by an ESS or Scheduling ESS.

Franchise Fees

Franchise fees related to Schedule 200, Base Supply Service, and distribution charges are collected through rates in this schedule.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 753

STREET LIGHTING SERVICE CONSUMER-OWNED SYSTEM
DIRECT ACCESS DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

This Schedule is applicable to Consumers who have chosen to receive electricity from an ESS. To lighting service provided to municipalities or agencies of municipal, county, state or federal governments for dusk to dawn illumination of public streets, highways and thoroughfares by means of Consumer owned street lighting systems controlled by a photoelectric control or time switch.

Monthly Billing

Energy Only Service - Rate per Luminaire

Energy Only Service includes energy supplied from Company's overhead or underground circuits and does not include any maintenance to Consumer's facilities. Maintenance service will be provided only as indicated in the Maintenance Service section below.

The Monthly Billing shall be the rate per luminaire specified in the rate tables below plus the applicable adjustments as specified in Schedule 90.

High Pressure Sodium Vapor						
Lumen Rating	5,800	9,500	16,000	22,000	27,500	50,000
Watts	70	100	150	200	250	400
Monthly kWh	31	44	64	85	115	176
Energy Only Service	$ 1.16	$ 1.65	$ 2.40	$ 3.19	$ 4.32	$ 6.61

(R)

Metal Halide					
Lumen Rating	9,000	12,000	19,500	32,000	107,800
Watts	100	175	250	400	1,000
Monthly kWh	39	68	94	149	354
Energy Only Service	$ 1.46	$ 2.55	$ 3.53	$ 5.60	$ 13.30

(R)

For non-listed luminaires the cost will be calculated for 4167 annual hours of operation including applicable loss factors for ballasts and starting aids at the cost per kWh given below.

Non-Listed Luminaire	¢/kWh
Energy Only Service	3.756

(R)

Maintenance Service (No New Service)

Where the utility operates and maintains the system, a flat rate equal to one-twelfth the estimated annual cost for operation and maintenance will be added to the Energy Only Service rates listed above. Monthly Maintenance is only applicable for existing monthly maintenance service agreements in effect prior to May 24, 2006.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

RECREATIONAL FIELD LIGHTING - RESTRICTED
DIRECT ACCESS DELIVERY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

This Schedule is applicable to Consumers who have chosen to receive electricity from an ESS. To schools, governmental agencies and nonprofit organizations for service supplied through one meter at one point of delivery and used exclusively for annually recurring seasonal lighting of outdoor athletic or recreational fields. This Schedule is not applicable to any enterprise which is operated for profit. Service for purposes other than recreational field lighting may not be combined with such field lighting for billing purposes under this Schedule. At Consumer's option, service for recreational field lighting may be taken under Company's applicable General Service Schedule.

Monthly Billing

The Monthly Billing shall be the Distribution Charge and the System Usage Charge plus the applicable adjustments as specified in Schedule 90.

Distribution Charge		
Basic Charge, Single Phase, per month	$ 6.00	
Basic Charge, Three Phase, per month	$ 9.00	
Distribution Energy Charge, per kWh	4.090¢	(R)
System Usage Charge		
Schedule 200 Related, per kWh	0.018¢	(R)

Minimum Charge

The minimum monthly charge shall be the Basic Charge.

Base Supply Service

All Consumers taking Delivery Service under this schedule shall pay the applicable rates in Schedule 200, Base Supply Service.

Transmission & Ancillary Services

Consumers taking service under this schedule must also take service under the Company's FERC Open Access Transmission Tariff (OATT) or be served by an ESS or Scheduling ESS.

Franchise Fees

Franchise fees related to Schedule 200, Base Supply Service, are collected through the System Usage Charge - Schedule 200 Related rate. Franchise fees related to distribution charges are collected through distribution charges.

Special Conditions

Consumer shall own all poles, wire and other distribution facilities beyond the Company's point of delivery.

Continuing Service

This Schedule is based on continuing service at each service location. Disconnect and reconnect transactions shall not operate to relieve a Consumer from monthly minimum charges.

Rules and Regulations

Service under this Schedule is subject to the General Rules and Regulations contained in the tariff of which this Schedule is a part and to those prescribed by regulatory authorities.

Purpose

To provide Consumers served on Schedule 747 with the opportunity of purchasing Energy from an ESS to replace some or all of the Consumer's on-site generation when the Consumer deems it is more economically beneficial than self generating.

Available

In all territory served by the Company in Oregon. The Company may limit service to a Consumer if system reliability would be affected. The Company has no obligation to provide the Consumer with economic replacement service except as explicitly agreed to between Company and Consumer.

Applicable

This Schedule is applicable to Consumers who have chosen to receive electricity from an ESS. To Large Nonresidential Consumers receiving Delivery Service under Schedule 747.

Character of Service

Sixty-hertz alternating current of such phase and voltage as the Company may have available.

Monthly Billing

The following charges are in addition to applicable charges under Schedule 747 plus the applicable adjustments as specified in Schedule 90:

	Delivery Voltage			
	Secondary	Primary	Transmission	
Daily ERS Demand Charge				
per kW of Daily ERS On-Peak Demand	$0.133	$0.142	$0.079	(R)

Transmission & Ancillary Services

Consumers taking service under this schedule must also take service under the Company's FERC Open Access Transmission Tariff (OATT) or be served by an ESS or Scheduling ESS.

ERS and ENF

Economic Replacement Service (ERS) is Electricity supplied by an ESS to meet an Energy Needs Forecast (ENF) pursuant to an Economic Replacement Service Agreement (ERSA).

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 848

LARGE GENERAL SERVICE 1,000 KW AND OVER
DIRECT ACCESS DELIVERY SERVICE – DISTRIBUTION ONLY

Available

In all territory served by the Company in the State of Oregon.

Applicable

This Schedule is applicable to Consumers who have chosen to receive electricity from an ESS and are participating in the New Large Load Direct Access Program in Schedule 293 or to existing consumers who have completed the five-year transition period for the Five-Year Cost of Service Opt-Out in Schedule 296. Existing consumers who have completed the five-year transition period for the Five-Year Cost of Service Opt-Out in Schedule 296 must have electric service loads which have registered 1,000 kW or more, more than once in a preceding 18-month period. This Schedule will remain applicable until Consumer fails to meet or exceed 1,000 kW for a subsequent period of 36 consecutive months. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one-year period will be provided only by special contract for such service.

Monthly Billing

The Monthly Billing shall be the Distribution Charge plus the applicable adjustments as specified in Schedule 90.

Distribution Charge		**Delivery Voltage**		
	Secondary	**Primary**	**Transmission**	
Basic Charge				
Facility Capacity ≤ 4000 kW, per month	$540.00	$530.00	$710.00	(R)(R)
Facility Capacity > 4000 kW, per month	$1,500.00	$1,470.00	$1,820.00	(R)(R)
Facilities Charge				
≤ 4000 kW, per kW Facility Capacity	$2.95	$1.25	$1.25	(I)(R)
> 4000 kW, per kW Facility Capacity	$0.80	$0.85	$1.05	
On-Peak Demand Charge, per kW	$3.42	$3.65	$2.04	(R)(R)(R)
Reactive Power Charge, per kvar	$0.65	$0.60	$0.55	

Facility Capacity

For determination of the Basic Charge and the Facilities Charge, the Facility Capacity shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

Minimum Charge

The minimum monthly charge shall be the Basic Charge and the Facilities Charge. A higher minimum may be required by contract.

(continued)

Issued March 1, 2022
Matthew McVee, Vice President, Regulation
Effective for service on and after January 1, 2023
Advice No. 22-002/Docket No. UE 399

I. Billing – General

Meters ordinarily will be read and bills rendered at intervals of approximately one month. Company reserves the right to bill any Consumer for a period shorter or longer than one month but in no event shall meters be read and bills rendered for any single period longer than six months. Each special meter reading made at the request of Consumer may be subject to an additional charge which reflects costs incurred by Company. Consumer shall be informed of and agree to charges prior to meter reading. Except for initial, final, Force Majeure bills and Residential kilowatt-hour seasons as described in Section A below, no bill will be prorated when (C)
service is used for less than a full month.

A. Residential Seasonal Kilowatt-Hour Proration (C)
Seasonal kilowatt-hour usage will be prorated to the nearest whole kilowatt-hour based (C)
upon the number of whole days in the billing period falling within each season. (C)

(D)

(continued)

Docket No. UE 399
Exhibit PAC/1102
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Unbundled Results of Operations - Summary and Detail

March 2022

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
Functionalized Revenue Requirement
12 Months Ended December 31, 2023 Forecast

Function		Revenue Requirement	
Production		$	749,838,433
Transmission		$	181,004,744
Distribution		$	399,594,389
Distribution-Lighting		$	3,324,376
Distribution Total		$	402,918,765
Ancillary		$	23,847,685
Customer Billing		$	15,188,944
Customer Metering		$	21,184,339
Customer Other		$	9,291,508
Retail Service	a	$	-
Public Purposes	b	$	-
Total State of Oregon		$	1,403,274,417

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

														Distribution Components	
								Distribution-		Customer			Poles &	Poles &	Franchise
				Total $	Production	Transmission	Distribution	Lighting	Ancillary	Billing	Metering	Other	Wires	Wires-Lighting	Fees
		ROR	ROE												
1	Functionalized Situs Revenues @ Earned	4.53%	4.67%	1,248,901,150	698,715,686	133,281,168	348,421,271	2,779,043	23,847,685	14,719,951	18,059,162	9,077,184	319,433,928	2,547,837	29,218,549
2	System Allocated Revenues			-	-	-	-	-	-	-	-	-	-	-	-
3	Total Oregon General Business Revenue			1,248,901,150	698,715,686	133,281,168	348,421,271	2,779,043	23,847,685	14,719,951	18,059,162	9,077,184	319,433,928	2,547,837	29,218,549
4															
5	Target Increase in Return	7.21%	9.80%	112,602,309	38,195,747	35,656,098	35,526,403	378,591	-	350,403	2,334,938	160,129	35,526,403	378,591	-
6															
7	Add														
8	Uncollectible Expense			771,495	255,491	238,503	255,743	2,725	-	2,344	15,618	1,071	237,636	2,532	18,300
9	Franchise Tax			3,627,772			3,589,520	38,252							3,627,772
10	Other Revenue Based Taxes			660,604	218,768	204,222	218,983	2,334	-	2,007	13,373	917	203,479	2,168	15,670
11	Inc Taxes - State			6,778,828	2,299,441	2,146,551	2,138,743	22,792	-	21,095	140,567	9,640	2,138,743	22,792	-
12	Inc Taxes - Federal			29,932,259	10,153,300	9,478,203	9,443,727	100,638	-	93,145	620,680	42,566	9,443,727	100,638	-
13	Total Increase Needed			154,373,268	51,122,747	47,723,576	51,173,118	545,332	-	468,993	3,125,177	214,324	47,549,987	506,722	3,661,741
14															
15	Total Oregon General Business Revenue @	7.21%	9.80%	1,403,274,418	749,838,433	181,004,744	399,594,389	3,324,376	23,847,685	15,188,944	21,184,339	9,291,508	366,983,916	3,054,559	32,880,290
16	Less: System Allocated Revenues			-	-	-	-	-	-	-	-	-	-	-	-
17	Total Unbundled Revenue Requirement			1,403,274,418	749,838,433	181,004,744	399,594,389	3,324,376	23,847,685	15,188,944	21,184,339	9,291,508	366,983,916	3,054,559	32,880,290
18															
19	Rate Base			4,199,121,534	1,424,380,946	1,329,673,331	1,324,836,797	14,118,283	-	13,067,082	87,073,613	5,971,482	1,324,836,797	14,118,283	-
					33.92%	31.67%	31.55%	0.34%	0.00%	0.31%	2.07%	0.14%	31.55%	0.34%	0.00%

Notes:
Row 9: Franchise Tax @ 2.35%
Row 11: Inc Taxes - State 4.54%
Row 12: Inc Taxes - Federal 21.00%

Docket No. UE 399
Exhibit PAC/1103
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Functionalized Oregon Results of Operations Report

March 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	1,248,901,150	698,715,686	133,281,168	348,421,271	2,779,043	23,847,685	14,719,951	18,059,162	9,077,184
Special Sales	92,708,477	92,708,477	-	-	-	-	-	-	-
Other Operating Revenues	81,179,990	38,936,768	60,434,442	4,104,857	3,204	(23,847,685)	661,823	390,032	496,550
Total Operating Revenues	1,422,789,617	830,360,932	193,715,609	352,526,128	2,782,247	-	15,381,774	18,449,194	9,573,734
Operating Expenses									
Steam Production	238,036,042	238,036,042	-	-	-	-	-	-	-
Nuclear Production	-	-	-	-	-	-	-	-	-
Hydro Production	12,077,585	12,077,585	-	-	-	-	-	-	-
Other Power Supply	343,636,569	343,636,569	-	-	-	-	-	-	-
ECD	-	-	-	-	-	-	-	-	-
Transmission	60,587,175	201,730	60,385,445	-	-	-	-	-	-
Distribution	116,940,088	-	-	114,306,114	874,599	-	-	1,759,374	-
Customer Accounts	23,492,890	3,670,779	856,359	1,558,413	12,299	-	9,681,818	3,847,829	3,865,393
Customer Service	6,029,376	-	-	3,710,056	-	-	-	-	2,319,320
Sales	-	-	-	-	-	-	-	-	-
Administrative & General	60,742,837	14,987,633	6,062,882	34,150,269	180,571	-	1,914,858	2,447,475	999,149
Total O & M Expenses	861,542,561	612,610,337	67,304,687	153,724,852	1,067,470	-	11,596,676	8,054,679	7,183,862
Depreciation	287,994,295	184,502,530	40,225,922	58,597,189	829,712	-	550,435	2,988,279	300,228
Amortization Expense	43,237,301	5,795,483	1,660,641	29,375,575	45,969	-	2,363,170	2,356,565	1,639,897
Taxes Other Than Income	84,171,808	24,456,422	12,622,760	45,488,639	196,642	-	321,645	876,129	209,570
Income Taxes - Federal	(61,296,146)	(73,814,488)	2,905,895	9,639,311	263,277	-	(494,435)	564,566	(360,273)
Income Taxes - State	4,230,426	2,468,939	575,981	1,048,177	8,273	-	45,735	54,856	28,466
Income Taxes - Def Net	12,660,019	10,316,399	8,177,502	(5,882,254)	(268,741)	-	406,528	(390,854)	301,439
Investment Tax Credit Adj.	-	-	-	-	-	-	-	-	-
Misc Revenue & Expense	3,165	(507,960)	(208)	511,333	-	-	-	-	-
Total Operating Expenses	1,232,543,429	765,827,662	133,473,180	292,502,823	2,142,601	-	14,789,754	14,504,220	9,303,189
Operating Revenue for Return	190,246,188	64,533,270	60,242,429	60,023,304	639,646	-	592,020	3,944,973	270,545
Rate Base									
Electric Plant in Service	8,852,783,093	3,772,543,856	2,125,517,618	2,694,175,792	33,216,336	-	49,538,693	145,315,143	32,475,655
Plant Held for Future Use	-	1,762,429	(562,535)	(1,126,001)	-	-	(36,884)	(37,008)	-
Misc Deferred Debits	67,300,330	57,747,019	3,109,293	4,471,781	71,600	-	729,361	769,574	401,700
Elec Plant Acq Adj	701,604	701,604	-	-	-	-	-	-	-
Nuclear Fuel	-	-	-	-	-	-	-	-	-
Prepayments	11,129,917	4,754,958	1,152,784	3,627,057	58,026	-	589,668	622,635	324,789
Fuel Stock	43,192,126	43,192,126	-	-	-	-	-	-	-
Material & Supplies	81,719,811	66,753,694	1,208,964	13,319,385	-	-	-	437,768	-
Working Capital	13,347,565	5,022,220	1,471,478	5,174,255	65,382	-	626,090	636,191	351,949
Weatherization Loans	-	-	-	-	-	-	-	-	-
Miscellaneous Rate Base	-	-	-	-	-	-	-	-	-
Total Electric Plant	9,070,174,446	3,952,477,905	2,131,897,602	2,719,642,270	33,411,344	-	51,446,928	147,744,303	33,554,093
Rate Base Deductions									
Accum Prov For Depr	(3,571,364,011)	(1,740,982,885)	(579,491,671)	(1,198,794,615)	(16,682,711)	-	(3,399,166)	(30,162,765)	(1,850,199)
Accum Prov For Amort	(218,109,109)	(72,164,303)	(20,477,039)	(49,139,039)	(766,899)	-	(32,286,235)	(21,010,836)	(22,264,757)
Accum Def Income Taxes	(643,480,187)	(314,240,940)	(179,474,281)	(136,156,929)	(1,680,147)	-	(1,298,298)	(7,930,873)	(2,698,719)
Unamortized ITC	(45,778)	(18,624)	(3,492)	(16,420)	(263)	-	(2,678)	(2,826)	(1,475)
Customer Adv for Const	(23,030,533)	-	(20,960,626)	(1,961,291)	(23,889)	-	-	(84,727)	-
Customer Service Deposits	-	-	-	-	-	-	-	-	-
Misc. Rate Base Deductions	(415,023,294)	(400,690,208)	(1,817,162)	(8,737,180)	(139,153)	-	(1,393,468)	(1,478,662)	(767,461)
Total Rate Base Deductions	(4,871,052,912)	(2,528,096,959)	(802,224,271)	(1,394,805,473)	(19,293,062)	-	(38,379,846)	(60,670,690)	(27,582,611)
Total Rate Base	4,199,121,534	1,424,380,946	1,329,673,331	1,324,836,797	14,118,283	-	13,067,082	87,073,613	5,971,482
Return on Rate Base	4.5306%	4.5306%	4.5306%	4.5306%	4.5306%	4.5306%	4.5306%	4.5306%	4.5306%
Return on Equity	4.6678%	4.6678%	4.6678%	4.6678%	4.6678%	4.6678%	4.6678%	4.6678%	4.6678%

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	1,248,901,150	698,715,686	133,281,168	348,421,271	2,779,043	23,847,685	14,719,951	18,059,162	9,077,184	-
	General Business Revenues	-	-	-	-	-	-	-	-	-	-
	Interdepartmental	-	-	-	-	-	-	-	-	-	-
	Special Sales	92,708,477	92,708,477	-	-	-	-	-	-	-	-
	Other Operating Revenues	81,179,990	38,936,768	60,434,442	4,104,857	3,204	(23,847,685)	661,823	390,032	496,550	-
	Total Operating Revenues	1,422,789,617	830,360,932	193,715,609	352,526,128	2,782,247	-	15,381,774	18,449,194	9,573,734	-
Operating Expenses											
	Steam Production	238,036,042	238,036,042	-	-	-	-	-	-	-	-
Operating Expenses	Nuclear Production	-	-	-	-	-	-	-	-	-	-
	Hydro Production	12,077,585	12,077,585	-	-	-	-	-	-	-	-
	Other Power Supply	343,636,569	343,636,569	-	-	-	-	-	-	-	-
	ECD	-	-	-	-	-	-	-	-	-	-
	Transmission	60,587,175	201,730	60,385,445	-	-	-	-	-	-	-
	Distribution	116,940,088	-	-	114,306,114	874,599	-	-	1,759,374	-	-
	Customer Accounts	23,492,890	3,670,779	856,359	1,558,413	12,299	-	9,681,818	3,847,829	3,865,393	-
	Customer Service	6,029,376	-	-	3,710,056	-	-	-	-	2,319,320	-
	Sales	-	-	-	-	-	-	-	-	-	-
	Administrative & General	60,742,837	14,987,633	6,062,882	34,150,269	180,571	-	1,914,858	2,447,475	999,149	-
	Total O & M Expenses	861,542,561	612,610,337	67,304,687	153,724,852	1,067,470	-	11,596,676	8,054,679	7,183,862	-
	Depreciation	287,994,295	184,502,530	40,225,922	58,597,189	829,712	-	550,435	2,988,279	300,228	-
	Amortization Expense	43,237,301	5,795,483	1,660,641	29,375,575	45,969	-	2,363,170	2,356,565	1,639,897	-
	Taxes Other Than Income	84,171,808	24,456,422	12,622,760	45,488,639	196,642	-	321,645	876,129	209,570	-
	Income Taxes - Federal	(61,296,146)	(73,814,488)	2,905,895	9,639,311	263,277	-	(494,435)	564,566	(360,273)	-
	Income Taxes - State	4,230,426	2,468,939	575,981	1,048,177	8,273	-	45,735	54,856	28,466	-
	Income Taxes - Def Net	12,660,019	10,316,399	8,177,502	(5,882,254)	(268,741)	-	406,528	(390,854)	301,439	-
	Investment Tax Credit Adj.	-	-	-	-	-	-	-	-	-	-
	Misc Revenue & Expense	3,165	(507,960)	(208)	511,333	-	-	-	-	-	-
	Total Operating Expenses	1,232,543,429	765,827,662	133,473,180	292,502,823	2,142,601	-	14,789,754	14,504,220	9,303,189	-
Operating Revenue for Return		190,246,188	64,533,270	60,242,429	60,023,304	639,646	-	592,020	3,944,973	270,545	-
Rate Base											
	Electric Plant in Service	8,852,783,093	3,772,543,856	2,125,517,618	2,694,175,792	33,216,336	-	49,538,693	145,315,143	32,475,655	-
Rate Base	Plant Held for Future Use	-	1,762,429	(562,535)	(1,126,001)	-	-	(36,884)	(37,008)	-	-
	Misc Deferred Debits	67,300,330	57,747,019	3,109,293	4,471,781	71,600	-	729,361	769,574	401,700	-
	Elec Plant Acq Adj	701,604	701,604	-	-	-	-	-	-	-	-
	Nuclear Fuel	-	-	-	-	-	-	-	-	-	-
	Prepayments	11,129,917	4,754,958	1,152,784	3,627,057	58,026	-	589,668	622,635	324,789	-
	Fuel Stock	43,192,126	43,192,126	-	-	-	-	-	-	-	-
	Material & Supplies	81,719,811	66,753,694	1,208,964	13,319,385	-	-	-	437,768	-	-
	Working Capital	13,347,565	5,022,220	1,471,478	5,174,255	65,382	-	626,090	636,191	351,949	-
	Weatherization Loans	-	-	-	-	-	-	-	-	-	-
	Miscellaneous Rate Base	-	-	-	-	-	-	-	-	-	-
	Total Electric Plant	9,070,174,446	3,952,477,905	2,131,897,602	2,719,642,270	33,411,344	-	51,446,928	147,744,303	33,554,093	-
Rate Base Deductions											
	Accum Prov For Depr	(3,571,364,011)	(1,740,982,885)	(579,491,671)	(1,198,794,615)	(16,682,711)	-	(3,399,166)	(30,162,765)	(1,850,199)	-
Rate Base Deductions	Accum Prov For Amort	(218,109,109)	(72,164,303)	(20,477,039)	(49,139,039)	(766,899)	-	(32,286,235)	(21,010,836)	(22,264,757)	-
	Accum Def Income Taxes	(643,480,187)	(314,240,940)	(179,474,281)	(136,156,929)	(1,680,147)	-	(1,298,298)	(7,930,873)	(2,698,719)	-
	Unamortized ITC	(45,778)	(18,624)	(3,492)	(16,420)	(263)	-	(2,678)	(2,826)	(1,475)	-
	Customer Adv for Const	(23,030,533)	-	(20,960,626)	(1,961,291)	(23,889)	-	-	(84,727)	-	-
	Customer Service Deposits	-	-	-	-	-	-	-	-	-	-
	Misc. Rate Base Deductions	(415,023,294)	(400,690,208)	(1,817,162)	(8,737,180)	(139,153)	-	(1,393,468)	(1,478,662)	(767,461)	-
	Total Rate Base Deductions	(4,871,052,912)	(2,528,096,959)	(802,224,271)	(1,394,805,473)	(19,293,062)	-	(38,379,846)	(60,670,690)	(27,582,611)	-
Total Rate Base		4,199,121,534	1,424,380,946	1,329,673,331	1,324,836,797	14,118,283	-	13,067,082	87,073,613	5,971,482	-
Return on Rate Base		4.531%	4.531%	4.531%	4.531%	4.531%	4.531%	4.531%	4.531%	4.531%	0.000%
Return on Equity		4.668%	4.668%	4.668%	4.668%	4.668%	4.668%	4.668%	4.668%	4.668%	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	613,521,236	698,715,686	133,281,168	348,421,271	2,779,043	23,847,685	14,719,951	18,059,162	9,077,184	-
	Less Klamath Surcharge Revenue												
		P	S	-	-	-	-	-	-	-	-	-	-
				613,521,236	698,715,686	133,281,168	348,421,271	2,779,043	23,847,685	14,719,951	18,059,162	9,077,184	-
442	Commercial & Industrial Sales												
			S	631,085,295									
		P	SE	-	-	-	-	-	-	-	-	-	-
		PT	SG	-	-	-	-	-	-	-	-	-	-
				631,085,295	-	-	-	-	-	-	-	-	-
444	Public Street & Highway Lighting												
			S	4,294,618									
			SO	-									
				4,294,618	-	-	-	-	-	-	-	-	-
445	Other Sales to Public Authority												
			S	-									
				-	-	-	-	-	-	-	-	-	-
448	Interdepartmental												
		D_SPLIT	S	-	-	-	-	-	-	-	-	-	-
		GP	SO	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
Total Sales to Ultimate Customers				**1,248,901,150**	**698,715,686**	**133,281,168**	**348,421,271**	**2,779,043**	**23,847,685**	**14,719,951**	**18,059,162**	**9,077,184**	**-**

447	Sales for Resale-Non NPC												
		P	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
447NPC	Sales for Resale-NPC												
		P	SG	92,708,477	92,708,477	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				92,708,477	92,708,477	-	-	-	-	-	-	-	-
	Total Sales for Resale			92,708,477	92,708,477	-	-	-	-	-	-	-	-
449	Provision for Rate Refund												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SG	(844,658)	(844,658)	-	-	-	-	-	-	-	-
				(844,658)	(844,658)	-	-	-	-	-	-	-	-
Total Sales from Electricity				**1,340,764,969**	**790,579,506**	**133,281,168**	**348,421,271**	**2,779,043**	**23,847,685**	**14,719,951**	**18,059,162**	**9,077,184**	**-**
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	14,354	-	-	14,354	-	-	-	-	-	-
				1,560,331	-	-	14,354	-	-	676,542	376,017	493,418	-
453	Water Sales												
		P	SG	1,916	1,916	-	-	-	-	-	-	-	-
				1,916	1,916	-	-	-	-	-	-	-	-
454	Rent of Electric Property												
		D	S	4,606,685	-	-	4,606,685	-	-	-	-	-	-
		T	SG	1,269,017	-	1,269,017	-	-	-	-	-	-	-
		GP	SO	853,809	363,844	204,996	259,841	3,204	-	4,778	14,015	3,132	-
				6,729,512	363,844	1,474,013	4,866,526	3,204	-	4,778	14,015	3,132	-
	Oregon Ancillary Services				23,847,685				(23,847,685)				
456	Other Electric Revenue												
		OTHSGR	S	28,036,644	6,429,957	21,605,877	810	-	-	-	-	-	-
		C_BILLING	CN	-	-	-	-	-	-	-	-	-	-
		OTHSE	SE	6,649,054	-	6,649,054	-	-	-	-	-	-	-
		OTHSO	SO	(777,986)	-	-	(777,986)	-	-	-	-	-	-
		OTHSGR	SG	39,844,674	9,138,024	30,705,498	1,152	-	-	-	-	-	-
				73,752,386	15,567,981	58,960,429	(776,024)	-	-	-	-	-	-
	Total Other Electric Revenues			**82,024,648**	**39,781,426**	**60,434,442**	**4,104,857**	**3,204**	**(23,847,685)**	**661,823**	**390,032**	**496,550**	**-**
Total Electric Operating Revenues				**1,422,789,617**	**830,360,932**	**193,715,609**	**352,526,128**	**2,782,247**	**-**	**15,381,774**	**18,449,194**	**9,573,734**	**-**
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	(801)	(348)	(208)	(246)	-	-	-	-	-	-
		P	SG	(507,601)	(507,601)	-	-	-	-	-	-	-	-
				3,177	(507,948)	(208)	511,333	-	-	-	-	-	-
Total Miscellaneous Revenues				**3,165**	**(507,960)**	**(208)**	**511,333**	**-**	**-**	**-**	**-**	**-**	**-**
Miscellaneous Expenses													
4311	Interest on Customer Deposits												
		C_BILLING	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
Total Miscellaneous Expenses				**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Net Misc Revenue and Expense				**3,165**	**(507,960)**	**(208)**	**511,333**	**-**	**-**	**-**	**-**	**-**	**-**
500	Operation Supervision & Engineering												
		P	SG	3,814,692	3,814,692	-	-	-	-	-	-	-	-
		P	SG	305,930	305,930	-	-	-	-	-	-	-	-
		P	SG	(15)	(15)	-	-	-	-	-	-	-	-
				4,120,607	4,120,607	-	-	-	-	-	-	-	-
501	Fuel Related-Non NPC												
		P	S	5,325,016	5,325,016	-	-	-	-	-	-	-	-
		P	SE	8,179,260	8,179,260	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-

		P	SE	-	-	-	-	-	-	-	-	-	-
		P	SE	71,745	71,745	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
				13,576,021	13,576,021	-	-	-	-	-	-	-	-
501NPC	Fuel Related-NPC												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SE	145,908,002	145,908,002	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
		P	SE	7,781,339	7,781,339	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
				153,689,341	153,689,341	-	-	-	-	-	-	-	-
	Total Fuel Related			167,265,362	167,265,362	-	-	-	-	-	-	-	-
502	Steam Expenses												
		P	SG	21,162,834	21,162,834	-	-	-	-	-	-	-	-
		P	SG	1,302,554	1,302,554	-	-	-	-	-	-	-	-
		P	SG	0	0	-	-	-	-	-	-	-	-
				22,465,388	22,465,388	-	-	-	-	-	-	-	-
503	Steam From Other Sources-Non-NPC												
		P	SE	(610)	(610)	-	-	-	-	-	-	-	-
				(610)	(610)	-	-	-	-	-	-	-	-
503NPC	Steam From Other Sources-NPC												
		P	SE	1,124,082	1,124,082	-	-	-	-	-	-	-	-
				1,124,082	1,124,082	-	-	-	-	-	-	-	-
505	Electric Expenses												
		P	SG	293,368	293,368	-	-	-	-	-	-	-	-
		P	SG	37,001	37,001	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				330,369	330,369	-	-	-	-	-	-	-	-
506	Misc. Steam Expense												
		P	SG	15,969,987	15,969,987	-	-	-	-	-	-	-	-
		P	SG	(14,112,418)	(14,112,418)	-	-	-	-	-	-	-	-
		P	SG	408,646	408,646	-	-	-	-	-	-	-	-
				2,266,215	2,266,215	-	-	-	-	-	-	-	-
507	Rents												
		P	SG	131,637	131,637	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	67	67	-	-	-	-	-	-	-	-
				131,704	131,704	-	-	-	-	-	-	-	-
510	Maint Supervision & Engineering												
		P	SG	1,653,017	1,653,017	-	-	-	-	-	-	-	-
		P	SG	296,875	296,875	-	-	-	-	-	-	-	-
		P	SG	158,733	158,733	-	-	-	-	-	-	-	-
				2,108,625	2,108,625	-	-	-	-	-	-	-	-
511	Maintenance of Structures												
		P	SG	6,108,182	6,108,182	-	-	-	-	-	-	-	-
		P	SG	711,090	711,090	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				6,819,272	6,819,272	-	-	-	-	-	-	-	-
512	Maintenance of Boiler Plant												
		P	SG	18,853,516	18,853,516	-	-	-	-	-	-	-	-
		P	SG	486,746	486,746	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				19,340,261	19,340,261	-	-	-	-	-	-	-	-
513	Maintenance of Electric Plant												
		P	SG	8,630,491	8,630,491	-	-	-	-	-	-	-	-
		P	SG	83,912	83,912	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				8,714,403	8,714,403	-	-	-	-	-	-	-	-
514	Maintenance of Misc. Steam Plant												
		P	SG	2,942,439	2,942,439	-	-	-	-	-	-	-	-
		P	SG	407,929	407,929	-	-	-	-	-	-	-	-
		P	SG	(6)	(6)	-	-	-	-	-	-	-	-
				3,350,362	3,350,362	-	-	-	-	-	-	-	-
Total Steam Power Generation				**238,036,042**	**238,036,042**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
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	(634)	(634)	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	2,645,604	2,645,604	-	-	-	-	-	-	-	-
		P	SG	432,509	432,509	-	-	-	-	-	-	-	-
				3,077,463	3,077,463	-	-	-	-	-	-	-	-
536	Water For Power												
		P	DGP	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	83,342	83,342	-	-	-	-	-	-	-	-
				83,342	83,342	-	-	-	-	-	-	-	-
537	Hydraulic Expenses												
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	1,181,426	1,181,426	-	-	-	-	-	-	-	-
		P	SG	90,386	90,386	-	-	-	-	-	-	-	-
				1,271,812	1,271,812	-	-	-	-	-	-	-	-
538	Electric Expenses												
		P	DGP	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
539	Misc. Hydro Expenses												
		P	SG	15	15	-	-	-	-	-	-	-	-
		P	SG	3,295,206	3,295,206	-	-	-	-	-	-	-	-
		P	SG	1,816,085	1,816,085	-	-	-	-	-	-	-	-
				5,111,306	5,111,306	-	-	-	-	-	-	-	-
540	Rents (Hydro Generation)												
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	408,188	408,188	-	-	-	-	-	-	-	-
		P	SG	18,221	18,221	-	-	-	-	-	-	-	-
				426,410	426,410	-	-	-	-	-	-	-	-
541	Maint Supervision & Engineering												
		P	DGP	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	107	107	-	-	-	-	-	-	-	-
				107	107	-	-	-	-	-	-	-	-
542	Maintenance of Structures												
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	206,101	206,101	-	-	-	-	-	-	-	-
		P	SG	20,182	20,182	-	-	-	-	-	-	-	-
				226,282	226,282	-	-	-	-	-	-	-	-
543	Maintenance of Dams & Waterways												
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	192,549	192,549	-	-	-	-	-	-	-	-
		P	SG	98,609	98,609	-	-	-	-	-	-	-	-
				291,159	291,159	-	-	-	-	-	-	-	-
544	Maintenance of Electric Plant												
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	450,909	450,909	-	-	-	-	-	-	-	-
		P	SG	69,322	69,322	-	-	-	-	-	-	-	-
				520,231	520,231	-	-	-	-	-	-	-	-
545	Maintenance of Misc. Hydro Plant												
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	836,324	836,324	-	-	-	-	-	-	-	-
		P	SG	233,149	233,149	-	-	-	-	-	-	-	-
				1,069,473	1,069,473	-	-	-	-	-	-	-	-
Total Hydraulic Power Generation				**12,077,585**	**12,077,585**	-	-	-	-	-	-	-	-
546	Operation Super & Engineering												
		P	SG	90,755	90,755	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	(3)	(3)	-	-	-	-	-	-	-	-
				90,752	90,752	-	-	-	-	-	-	-	-
547	Fuel-Non-NPC												
		P	SE	-	-	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
547NPC	Fuel-NPC												
		P	SE	77,422,181	77,422,181	-	-	-	-	-	-	-	-

		P	SE	496,371	496,371	-	-	-	-	-	-	-	-
				77,918,552	77,918,552	-	-	-	-	-	-	-	-
548	Generation Expense												
		P	SG	4,955,807	4,955,807	-	-	-	-	-	-	-	-
		P	SG	107,687	107,687	-	-	-	-	-	-	-	-
		P	SG	(79)	(79)	-	-	-	-	-	-	-	-
				5,063,415	5,063,415	-	-	-	-	-	-	-	-
549	Miscellaneous Other												
		P	S	34,592	34,592	-	-	-	-	-	-	-	-
		P	SG	1,109,540	1,109,540	-	-	-	-	-	-	-	-
		P	SG	1,270,008	1,270,008	-	-	-	-	-	-	-	-
		P	SG	(8,715)	(8,715)	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				2,405,425	2,405,425	-	-	-	-	-	-	-	-
550	Maint Supervision & Engineering												
		P	S	410,642	410,642	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	11,561	11,561	-	-	-	-	-	-	-	-
		P	SG	2,104,117	2,104,117	-	-	-	-	-	-	-	-
				2,526,321	2,526,321	-	-	-	-	-	-	-	-
551	Maint Supervision & Engineering												
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
552	Maintenance of Structures												
		P	SG	637,793	637,793	-	-	-	-	-	-	-	-
		P	SG	14,486	14,486	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				652,279	652,279	-	-	-	-	-	-	-	-
553	Maint of Generation & Electric Plant												
		P	SG	1,067,843	1,067,843	-	-	-	-	-	-	-	-
		P	SG	3,087,727	3,087,727	-	-	-	-	-	-	-	-
		P	SG	65,417	65,417	-	-	-	-	-	-	-	-
		P	SG	571,969	571,969	-	-	-	-	-	-	-	-
				4,792,956	4,792,956	-	-	-	-	-	-	-	-
554	Maintenance of Misc. Other												
		P	SG	571,642	571,642	-	-	-	-	-	-	-	-
		P	SG	280,792	280,792	-	-	-	-	-	-	-	-
		P	SG	20,931	20,931	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				873,365	873,365	-	-	-	-	-	-	-	-
Total Other Power Generation				**94,323,065**	**94,323,065**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
555	Purchased Power-Non NPC												
		P	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
555NPC	Purchased Power-NPC												
		P	S	(430,221)	(430,221)	-	-	-	-	-	-	-	-
		P	SG	236,092,898	236,092,898	-	-	-	-	-	-	-	-
		P	SE	11,211,701	11,211,701	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	DGP	-	-	-	-	-	-	-	-	-	-
				246,874,378	246,874,378	-	-	-	-	-	-	-	-
	Total Purchased Power			246,874,378	246,874,378	-	-	-	-	-	-	-	-
556	System Control & Load Dispatch												
		P	SG	166,747	166,747	-	-	-	-	-	-	-	-
				166,747	166,747	-	-	-	-	-	-	-	-
557	Other Expenses												
		P	S	3,316,961	3,316,961	-	-	-	-	-	-	-	-
		P	SG	9,953,088	9,953,088	-	-	-	-	-	-	-	-
		P	SGCT	-	-	-	-	-	-	-	-	-	-
		P	SE	2,331	2,331	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	TROJP	-	-	-	-	-	-	-	-	-	-
				13,272,379	13,272,379	-	-	-	-	-	-	-	-
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				**249,313,504**	**249,313,504**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
TOTAL PRODUCTION EXPENSE				**593,750,196**	**593,750,196**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Embedded Cost Differentials												
	Company Ownec	P	DGP	-	-	-	-	-	-	-	-	-	-
	Company Ownec	P	SG	-	-	-	-	-	-	-	-	-	-
	Mid-C Contract	P	MC	-	-	-	-	-	-	-	-	-	-
	Mid-C Contract	P	SG	-	-	-	-	-	-	-	-	-	-
	Existing QF Con	P	S	-	-	-	-	-	-	-	-	-	-
	Existing QF Con	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	2,469,731	-	2,469,731	-	-	-	-	-	-	-
		T	SG	(243)	-	(243)	-	-	-	-	-	-	-

				2,469,487	-	2,469,487	-	-	-	-	-	-	-
561	Load Dispatching												
		T	SG	4,872,252	-	4,872,252	-	-	-	-	-	-	-
		T	SG	(39)	-	(39)	-	-	-	-	-	-	-
				4,872,213	-	4,872,213	-	-	-	-	-	-	-
562	Station Expense												
		T	SG	884,923	-	884,923	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-	-
				884,923	-	884,923	-	-	-	-	-	-	-
563	Overhead Line Expense												
		T	SG	263,329	-	263,329	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-	-
				263,329	-	263,329	-	-	-	-	-	-	-
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	38,695,804	-	38,695,804	-	-	-	-	-	-	-
		T	SE	3,105,531	-	3,105,531	-	-	-	-	-	-	-
				41,801,335	-	41,801,335	-	-	-	-	-	-	-
	Total Transmission of Electricity by Others			41,801,335	-	41,801,335	-	-	-	-	-	-	-
566	Misc. Transmission Expense												
		T	SG	984,585	-	984,585	-	-	-	-	-	-	-
		T	SG	(1,236,567)	-	(1,236,567)	-	-	-	-	-	-	-
				(251,982)	-	(251,982)	-	-	-	-	-	-	-
567	Rents - Transmission												
		T	SG	677,134	-	677,134	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-	-
				677,134	-	677,134	-	-	-	-	-	-	-
568	Maint Supervision & Engineering												
		T	SG	232,098	-	232,098	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-	-
				232,098	-	232,098	-	-	-	-	-	-	-
569	Maintenance of Structures												
		T	SG	1,459,608	-	1,459,608	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-	-
				1,459,608	-	1,459,608	-	-	-	-	-	-	-
570	Maintenance of Station Equipment												
		STEP_UP	SG	2,869,004	201,730	2,667,274	-	-	-	-	-	-	-
		STEP_UP	SG	(0)	(0)	(0)	-	-	-	-	-	-	-
				2,869,004	201,730	2,667,274	-	-	-	-	-	-	-
571	Maintenance of Overhead Lines												
		T	SG	4,962,816	-	4,962,816	-	-	-	-	-	-	-
		T	SG	249,552	-	249,552	-	-	-	-	-	-	-
				5,212,368	-	5,212,368	-	-	-	-	-	-	-
572	Maintenance of Underground Lines												
		T	SG	47,632	-	47,632	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-	-
				47,632	-	47,632	-	-	-	-	-	-	-
573	Maint of Misc. Transmission Plant												
		T	SG	50,024	-	50,024	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-	-
				50,024	-	50,024	-	-	-	-	-	-	-
TOTAL TRANSMISSION EXPENSE				**60,587,175**	**201,730**	**60,385,445**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
580	Operation Supervision & Engineering												
		D_SPLIT	S	453,473	-	-	429,677	5,234	-	-	18,562	-	-
		D_SPLIT	SNPD	2,269,622	-	-	2,150,526	26,194	-	-	92,902	-	-
				2,723,095	-	-	2,580,204	31,427	-	-	111,464	-	-
581	Load Dispatching												
		D	S	-	-	-	-	-	-	-	-	-	-
		D	SNPD	3,549,774	-	-	3,549,774	-	-	-	-	-	-
				3,549,774	-	-	3,549,774	-	-	-	-	-	-
582	Station Expense												
		D	S	1,181,026	-	-	1,181,026	-	-	-	-	-	-
		D	SNPD	4,884	-	-	4,884	-	-	-	-	-	-
				1,185,910	-	-	1,185,910	-	-	-	-	-	-
583	Overhead Line Expenses												
		D	S	1,887,265	-	-	1,887,265	-	-	-	-	-	-
		D	SNPD	46	-	-	46	-	-	-	-	-	-
				1,887,312	-	-	1,887,312	-	-	-	-	-	-
584	Underground Line Expense												
		D	S	448	-	-	448	-	-	-	-	-	-
		D	SNPD	-	-	-	-	-	-	-	-	-	-
				448	-	-	448	-	-	-	-	-	-
585	Street Lighting & Signal Systems												
		DL	S	-	-	-	-	-	-	-	-	-	-
		DL	SNPD	90,751	-	-	-	90,751	-	-	-	-	-
				90,751	-	-	-	90,751	-	-	-	-	-
586	Meter Expenses												
		C_Meter	S	1,347,604	-	-	-	-	-	-	1,347,604	-	-
		C_Meter	SNPD	-	-	-	-	-	-	-	-	-	-
				1,347,604	-	-	-	-	-	-	1,347,604	-	-
587	Customer Installation Expenses												
		D	S	6,725,086	-	-	6,725,086	-	-	-	-	-	-
		D	SNPD	-	-	-	-	-	-	-	-	-	-
				6,725,086	-	-	6,725,086	-	-	-	-	-	-

588	Misc. Distribution Expenses												
		D	S	(122,388)	-	-	(122,388)	-	-	-	-	-	-
		D	SNPD	174,902	-	-	174,902	-	-	-	-	-	-
				52,513	-	-	52,513	-	-	-	-	-	-
589	Rents												
		D	S	2,010,384	-	-	2,010,384	-	-	-	-	-	-
		D	SNPD	7,210	-	-	7,210	-	-	-	-	-	-
				2,017,594	-	-	2,017,594	-	-	-	-	-	-
590	Maint Supervision & Engineering												
		D_SPLIT	S	870,564	-	-	824,882	10,047	-	-	35,635	-	-
		D_SPLIT	SNPD	712,784	-	-	675,381	8,226	-	-	29,176	-	-
				1,583,348	-	-	1,500,264	18,274	-	-	64,811	-	-
591	Maintenance of Structures												
		D	S	542,121	-	-	542,121	-	-	-	-	-	-
		D	SNPD	17,119	-	-	17,119	-	-	-	-	-	-
				559,240	-	-	559,240	-	-	-	-	-	-
592	Maintenance of Station Equipment												
		D	S	2,892,483	-	-	2,892,483	-	-	-	-	-	-
		D	SNPD	438,362	-	-	438,362	-	-	-	-	-	-
				3,330,846	-	-	3,330,846	-	-	-	-	-	-
593	Maintenance of Overhead Lines												
		D	S	81,068,804	-	-	81,068,804	-	-	-	-	-	-
		D	SNPD	897,936	-	-	897,936	-	-	-	-	-	-
				81,966,740	-	-	81,966,740	-	-	-	-	-	-
594	Maintenance of Underground Lines												
		D	S	7,588,671	-	-	7,588,671	-	-	-	-	-	-
		D	SNPD	6,531	-	-	6,531	-	-	-	-	-	-
				7,595,202	-	-	7,595,202	-	-	-	-	-	-
595	Maintenance of Line Transformers												
		D	S	-	-	-	-	-	-	-	-	-	-
		D	SNPD	308,422	-	-	308,422	-	-	-	-	-	-
				308,422	-	-	308,422	-	-	-	-	-	-
596	Maint of Street Lighting & Signal Sys.												
		DL	S	734,147	-	-	-	734,147	-	-	-	-	-
		DL	SNPD	-	-	-	-	-	-	-	-	-	-
				734,147	-	-	-	734,147	-	-	-	-	-
597	Maintenance of Meters												
		C_Meter	S	227,348	-	-	-	-	-	-	227,348	-	-
		C_Meter	SNPD	8,148	-	-	-	-	-	-	8,148	-	-
				235,496	-	-	-	-	-	-	235,496	-	-
598	Maint of Misc. Distribution Plant												
		D	S	(271,211)	-	-	(271,211)	-	-	-	-	-	-
		D	SNPD	1,317,770	-	-	1,317,770	-	-	-	-	-	-
				1,046,559	-	-	1,046,559	-	-	-	-	-	-
TOTAL DISTRIBUTION EXPENSE				**116,940,088**	**-**	**-**	**114,306,114**	**874,599**	**-**	**-**	**1,759,374**	**-**	**-**
901	Supervision												
		CUST901	S	-	-	-	-	-	-	-	-	-	-
		CUST901	CN	745,648	-	-	-	-	-	334,066	360,999	50,583	-
				745,648	-	-	-	-	-	334,066	360,999	50,583	-
902	Meter Reading Expense												
		C_Meter	S	2,480,518	-	-	-	-	-	-	2,480,518	-	-
		C_Meter	CN	128,242	-	-	-	-	-	-	128,242	-	-
				2,608,760	-	-	-	-	-	-	2,608,760	-	-
903	Customer Receipts & Collections												
		CUST903	S	813,440	-	-	-	-	-	545,411	46,814	221,214	-
		CUST903	CN	13,026,611	-	-	-	-	-	8,734,342	749,697	3,542,572	-
				13,840,051	-	-	-	-	-	9,279,753	796,511	3,763,786	-
904	Uncollectible Accounts												
		REVREQ	S	6,241,502	3,642,632	849,793	1,546,464	12,205	-	67,477	80,933	41,998	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		REVREQ	CN	48,229	28,147	6,566	11,950	94	-	521	625	325	-
				6,289,730	3,670,779	856,359	1,558,413	12,299	-	67,998	81,558	42,323	-
905	Misc. Customer Accounts Expense												
		CUST905	S	-	-	-	-	-	-	-	-	-	-
		CUST905	CN	8,701	-	-	-	-	-	-	-	8,701	-
				8,701	-	-	-	-	-	-	-	8,701	-
TOTAL CUSTOMER ACCOUNTS EXPENSE				**23,492,890**	**3,670,779**	**856,359**	**1,558,413**	**12,299**	**-**	**9,681,818**	**3,847,829**	**3,865,393**	**-**
907	Supervision												
		C_Service	S	-	-	-	-	-	-	-	-	-	-
		C_Service	CN	950	-	-	-	-	-	-	-	950	-
				950	-	-	-	-	-	-	-	950	-
908	Customer Assistance												
		DSM	S	3,710,056	-	-	3,710,056	-	-	-	-	-	-
		C_Service	CN	661,150	-	-	-	-	-	-	-	661,150	-
				4,371,206	-	-	3,710,056	-	-	-	-	661,150	-
909	Informational & Instructional Adv												
		C_Service	S	793,001	-	-	-	-	-	-	-	793,001	-
		C_Service	CN	863,621	-	-	-	-	-	-	-	863,621	-
				1,656,622	-	-	-	-	-	-	-	1,656,622	-
910	Misc. Customer Service												
		C_Service	S	-	-	-	-	-	-	-	-	-	-
		C_Service	CN	598	-	-	-	-	-	-	-	598	-
				598	-	-	-	-	-	-	-	598	-
TOTAL CUSTOMER SERVICE EXPENSE				**6,029,376**	**-**	**-**	**3,710,056**	**-**	**-**	**-**	**-**	**2,319,320**	**-**
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				**6,029,376**	**-**	**-**	**3,710,056**	**-**	**-**	**-**	**-**	**2,319,320**	**-**
920	Administrative & General Salaries												
		LABOR	S	739,506	300,859	56,417	265,246	4,247	-	43,262	45,648	23,827	-
		LABOR	CN	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	21,919,618	8,917,743	1,672,241	7,862,123	125,884	-	1,282,337	1,353,036	706,255	-
				22,659,124	9,218,602	1,728,657	8,127,368	130,131	-	1,325,599	1,398,684	730,082	-
921	Office Supplies & expenses												
		LABOR	S	1,944,169	790,963	148,320	697,334	11,165	-	113,737	120,008	62,642	-
		LABOR	CN	29,094	11,836	2,220	10,435	167	-	1,702	1,796	937	-
		LABOR	SO	2,755,810	1,121,169	210,240	988,453	15,827	-	161,220	170,108	88,793	-
				4,729,073	1,923,968	360,779	1,696,223	27,159	-	276,659	291,912	152,372	-
922	Office Supplies & expenses												
		LABOR	S	-	-	-	-	-	-	-	-	-	-
		LABOR	CN	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	(10,754,134)	(4,375,195)	(820,429)	(3,857,290)	(61,761)	-	(629,136)	(663,822)	(346,501)	-
				(10,754,134)	(4,375,195)	(820,429)	(3,857,290)	(61,761)	-	(629,136)	(663,822)	(346,501)	-
923	Outside Services												
		LABOR	S	239,952	97,622	18,306	86,066	1,378	-	14,038	14,812	7,731	-
		LABOR	CN	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	6,447,326	2,623,020	491,864	2,312,525	37,027	-	377,180	397,975	207,734	-
				6,687,278	2,720,642	510,170	2,398,591	38,405	-	391,218	412,787	215,466	-
924	Property Insurance												
		DPW	S	11,847,293	-	-	11,470,299	-	-	-	376,994	-	-
		PT	SG	-	-	-	-	-	-	-	-	-	-
		GP	SO	981,641	418,318	235,688	298,744	3,683	-	5,493	16,113	3,601	-
				12,828,933	418,318	235,688	11,769,042	3,683	-	5,493	393,107	3,601	-
925	Injuries & Damages												
		DPW	S	1,608,709	-	-	1,557,518	-	-	-	51,191	-	-
		LABOR	SO	8,980,098	3,653,449	685,089	3,220,979	51,573	-	525,352	554,316	289,341	-
				10,588,807	3,653,449	685,089	4,778,497	51,573	-	525,352	605,507	289,341	-
926	Employee Pensions & Benefits												
		LABOR	S	174,360	70,936	13,302	62,539	1,001	-	10,200	10,763	5,618	-
		LABOR	CN	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	32,482,216	13,215,013	2,478,058	11,650,712	186,545	-	1,900,267	2,005,036	1,046,584	-
				32,656,576	13,285,950	2,491,360	11,713,252	187,547	-	1,910,468	2,015,798	1,052,202	-
927	Franchise Requirements												
		DSM	S	-	-	-	-	-	-	-	-	-	-
		DSM	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
928	Regulatory Commission Expense												
		D	S	6,019,755	-	-	6,019,755	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
		D	SO	654,867	-	-	654,867	-	-	-	-	-	-
		FERC	SG	1,206,779	485,160	721,618	-	-	-	-	-	-	-
				7,881,401	485,160	721,618	6,674,622	-	-	-	-	-	-
929	Duplicate Charges												
		LABOR	S	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	(34,071,021)	(13,861,400)	(2,599,267)	(12,220,584)	(195,670)	-	(1,993,215)	(2,103,108)	(1,097,776)	-
				(34,071,021)	(13,861,400)	(2,599,267)	(12,220,584)	(195,670)	-	(1,993,215)	(2,103,108)	(1,097,776)	-
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	488,157	198,601	37,241	175,092	2,803	-	28,558	30,133	15,729	-
				(1,181,559)	(480,704)	(90,141)	(423,801)	(6,786)	-	(69,123)	(72,934)	(38,070)	-
931	Rents												
		LABOR	S	490,906	199,719	37,451	176,078	2,819	-	28,719	30,302	15,817	-
		LABOR	SO	604,360	245,877	46,106	216,772	3,471	-	35,356	37,305	19,473	-
				1,095,266	445,596	83,557	392,850	6,290	-	64,075	67,608	35,290	-
935	Maintenance of General Plant												
		G	S	157,258	32,080	56,917	64,057	-	-	2,098	2,105	-	-
		B_Center	CN	9,015	-	-	-	-	-	5,873	-	3,142	-
		G	SO	7,456,823	1,521,166	2,698,884	3,037,444	-	-	99,498	99,832	-	-
				7,623,096	1,553,246	2,755,801	3,101,501	-	-	107,469	101,937	3,142	-
TOTAL ADMINISTRATIVE & GEN EXPENSE				**60,742,837**	**14,987,633**	**6,062,882**	**34,150,269**	**180,571**	**-**	**1,914,858**	**2,447,475**	**999,149**	**-**
TOTAL O&M EXPENSE				**861,542,561**	**612,610,337**	**67,304,687**	**153,724,852**	**1,067,470**	**-**	**11,596,676**	**8,054,679**	**7,183,862**	**-**
403SP	Steam Depreciation												
		P	SG	10,537,740	10,537,740	-	-	-	-	-	-	-	-
		P	SG	8,762,657	8,762,657	-	-	-	-	-	-	-	-
		P	SG	94,925,664	94,925,664	-	-	-	-	-	-	-	-
		P	SG	1,978,660	1,978,660	-	-	-	-	-	-	-	-
				116,204,721	116,204,721	-	-	-	-	-	-	-	-
403NP	Nuclear Depreciation												
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
403HP	Hydro Depreciation												
		P	SG	(6,305,162)	(6,305,162)	-	-	-	-	-	-	-	-
		P	SG	351,595	351,595	-	-	-	-	-	-	-	-
		P	SG	12,762,530	12,762,530	-	-	-	-	-	-	-	-
		P	SG	2,289,221	2,289,221	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				9,098,184	9,098,184	-	-	-	-	-	-	-	-

403OP		Other Production Depreciation												
			P	S	-	-	-	-	-	-	-	-	-	-
			P	SG	-	-	-	-	-	-	-	-	-	-
			P	SG	18,026,942	18,026,942	-	-	-	-	-	-	-	-
			P	SG	964,028	964,028	-	-	-	-	-	-	-	-
			P	SG	35,740,655	35,740,655	-	-	-	-	-	-	-	-
					54,731,626	54,731,626	-	-	-	-	-	-	-	-
403TP		Transmission Depreciation												
			T_Split	S	-	-	-	-	-	-	-	-	-	-
			T_Split	SG	2,205,066	45,136	2,159,930	-	-	-	-	-	-	-
			T_Split	SG	2,766,921	56,637	2,710,285	-	-	-	-	-	-	-
			T_Split	SG	31,065,085	635,878	30,429,207	-	-	-	-	-	-	-
					36,037,072	737,651	35,299,422	-	-	-	-	-	-	-
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 Equipr	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	11,722,022	-	-	11,722,022	-	-	-	-	-	-
	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	-	-	-	-	-
					56,428,045	-	-	53,029,949	793,971	-	-	2,604,125	-	-
403GP		General Depreciation												
			TD	S	6,150,304	-	2,815,280	3,335,024	-	-	-	-	-	-
			G-DGP	SG	4,753	3,011	1,742	-	-	-	-	-	-	-
			G-DGU	SG	13,378	8,475	4,903	-	-	-	-	-	-	-
			P	SE	27,778	27,778	-	-	-	-	-	-	-	-
			B_Center	CN	286,062	-	-	-	-	-	186,354	-	99,708	-
			G-SG	SG	2,769,397	1,139,605	1,629,792	-	-	-	-	-	-	-
			LABOR	SO	6,223,423	2,531,928	474,783	2,232,216	35,741	-	364,081	384,154	200,520	-
			P	SG	2,134	2,134	-	-	-	-	-	-	-	-
			P	SG	17,417	17,417	-	-	-	-	-	-	-	-
					15,494,647	3,730,348	4,926,500	5,567,240	35,741	-	550,435	384,154	300,228	-
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					**287,994,295**	**184,502,530**	**40,225,922**	**58,597,189**	**829,712**	**-**	**550,435**	**2,988,279**	**300,228**	**-**
404GP		Amort of LT Plant - Capital Lease Gen												
			TD	S	322,905	-	147,808	175,096	-	-	-	-	-	-
			I-SG	SG	-	-	-	-	-	-	-	-	-	-
			LABOR	SO	29,426	11,972	2,245	10,555	169	-	1,721	1,816	948	-
			I-DGU	SG	-	-	-	-	-	-	-	-	-	-
			B_Center	CN	-	-	-	-	-	-	-	-	-	-
			I-DGP	SG	-	-	-	-	-	-	-	-	-	-
					352,331	11,972	150,053	185,651	169	-	1,721	1,816	948	-
404SP		Amort of LT Plant - Cap Lease Steam												
			P	SG	-	-	-	-	-	-	-	-	-	-
			P	SG	-	-	-	-	-	-	-	-	-	-
					-	-	-	-	-	-	-	-	-	-
404IP		Amort of LT Plant - Intangible Plant												
			TD	S	11,687	-	5,350	6,337	-	-	-	-	-	-
			P	SE	(3,225)	(3,225)	-	-	-	-	-	-	-	-
			I-SG	SG	1,834,082	1,204,381	628,199	1,454	-	-	-	48	-	-
			LABOR	SO	7,974,960	3,244,520	608,407	2,860,457	45,800	-	466,549	492,272	256,955	-
			CSS_SYS	CN	4,274,209	-	-	-	-	-	1,894,899	997,315	1,381,994	-
			I-SG	SG	698,755	458,849	239,334	554	-	-	-	18	-	-
			I-SG	SG	81,951	53,815	28,069	65	-	-	-	2	-	-
			I-DGP	SG	20,503	20,503	-	-	-	-	-	-	-	-
			I-SG	SG	-	-	-	-	-	-	-	-	-	-
			I-SG	SG	3,588	2,356	1,229	3	-	-	-	0	-	-
			I-DGU	SG	3,687	3,687	-	-	-	-	-	-	-	-
					14,900,197	4,984,887	1,510,588	2,868,869	45,800	-	2,361,449	1,489,655	1,638,949	-
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	81,260	81,260	-	-	-	-	-	-	-	-
			P	SG	-	-	-	-	-	-	-	-	-	-
			P	SG	-	-	-	-	-	-	-	-	-	-
					81,260	81,260	-	-	-	-	-	-	-	-
Total Amortization of Limited Term Plant					**15,333,788**	**5,078,118**	**1,660,641**	**3,054,520**	**45,969**	**-**	**2,363,170**	**1,491,472**	**1,639,897**	**-**
405		Amortization of Other Electric Plant												
			GP	S	-	-	-	-	-	-	-	-	-	-
					-	-	-	-	-	-	-	-	-	-

406	Amortization of Plant Acquisition Adj												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	466,658	466,658	-	-	-	-	-	-	-	-
		P	SO	-	-	-	-	-	-	-	-	-	-
				466,658	466,658	-	-	-	-	-	-	-	-
407	Amort of Prop Losses, Unrec Plant, etc												
		DPW	S	27,186,148	-	-	26,321,055	-	-	-	865,093	-	-
		GP	SO	-	-	-	-	-	-	-	-	-	-
		P	SG	250,707	250,707	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	TROJP	-	-	-	-	-	-	-	-	-	-
				27,436,855	250,707	-	26,321,055	-	-	-	865,093	-	-
TOTAL AMORTIZATION EXPENSE				**43,237,301**	**5,795,483**	**1,660,641**	**29,375,575**	**45,969**	**-**	**2,363,170**	**2,356,565**	**1,639,897**	**-**
408	Taxes Other Than Income												
		D	S	29,218,549	-	-	29,218,549	-	-	-	-	-	-
		GP	GPS	50,535,683	21,535,383	12,133,414	15,379,572	189,614	-	282,789	829,524	185,386	-
		REVREQ	SO	3,594,117	2,097,580	489,346	890,518	7,028	-	38,856	46,605	24,184	-
		P	SE	218,476	218,476	-	-	-	-	-	-	-	-
		P	SG	604,983	604,983	-	-	-	-	-	-	-	-
		DSM	OPRV-ID	-	-	-	-	-	-	-	-	-	-
		GP	EXCTAX	-	-	-	-	-	-	-	-	-	-
		GP	SG	-	-	-	-	-	-	-	-	-	-
				84,171,808	24,456,422	12,622,760	45,488,639	196,642	-	321,645	876,129	209,570	-
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	87,804,135	33,978,392	26,454,928	25,079,650	273,415	-	240,233	1,632,532	144,985	-
		NP	SNP	-	-	-	-	-	-	-	-	-	-
				87,804,135	33,978,392	26,454,928	25,079,650	273,415	-	240,233	1,632,532	144,985	-
428	Amortization of Debt Disc & Exp												
		NP	SNP	1,306,296	505,510	393,580	373,120	4,068	-	3,574	24,288	2,157	-
				1,306,296	505,510	393,580	373,120	4,068	-	3,574	24,288	2,157	-
429	Amortization of Premium on Debt												
		NP	SNP	(2,822)	(1,092)	(850)	(806)	(9)	-	(8)	(52)	(5)	-
				(2,822)	(1,092)	(850)	(806)	(9)	-	(8)	(52)	(5)	-
431	Other Interest Expense												
		NUTIL	OTH	-	-	-	-	-	-	-	-	-	-
		GP	SO	-	-	-	-	-	-	-	-	-	-
		NP	SNP	4,749,201	1,837,843	1,430,910	1,356,523	14,789	-	12,994	88,301	7,842	-
				4,749,201	1,837,843	1,430,910	1,356,523	14,789	-	12,994	88,301	7,842	-
432	AFUDC - Borrowed												
		NP	SNP	(9,808,081)	(3,795,525)	(2,955,124)	(2,801,499)	(30,542)	-	(26,835)	(182,361)	(16,195)	-
				(9,808,081)	(3,795,525)	(2,955,124)	(2,801,499)	(30,542)	-	(26,835)	(182,361)	(16,195)	-
	Total Electric Interest Deductions for Tax			84,048,729	32,525,127	25,323,444	24,006,986	261,721	-	229,959	1,562,708	138,784	-
	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			84,048,729	32,525,127	25,323,444	24,006,986	261,721	-	229,959	1,562,708	138,784	-
419	Interest & Dividends												
		GP	S	-	-	-	-	-	-	-	-	-	-
		GP	SNP	(21,356,078)	(9,100,725)	(5,127,508)	(6,499,315)	(80,130)	-	(119,505)	(350,552)	(78,343)	-
	Total Operating Deductions for Tax			(21,356,078)	(9,100,725)	(5,127,508)	(6,499,315)	(80,130)	-	(119,505)	(350,552)	(78,343)	-
41010	Deferred Income Tax - Federal-DR												
		GP	S	404,694	172,457	97,165	123,161	1,518	-	2,265	6,643	1,485	-
		P	SCHMDEXP	-	-	-	-	-	-	-	-	-	-
		PT	SG	133,089	83,335	49,753	-	-	-	-	-	-	-
		LABOR	SO	1,798,756	731,803	137,227	645,177	10,330	-	105,230	111,032	57,956	-
		NP	SNP	7,425,983	2,873,702	2,237,410	2,121,097	23,124	-	20,318	138,070	12,262	-
		P	SE	9,431	9,431	-	-	-	-	-	-	-	-
		PT	SG	8,911,973	5,580,346	3,331,627	-	-	-	-	-	-	-
		GP	GPS	3,271,373	1,394,070	785,443	995,580	12,274	-	18,306	53,698	12,001	-
		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	-	-	-	-	-	-	-	-	-	-
				111,083,207	66,289,686	23,441,341	19,472,186	65,060	-	663,722	729,335	421,877	-
41110	Deferred Income Tax - Federal-CR												
		GP	S	(20,437,298)	(8,709,194)	(4,906,913)	(6,219,702)	(76,682)	-	(114,364)	(335,471)	(74,972)	-
		P	SE	(1,043,257)	(1,043,257)	-	-	-	-	-	-	-	-
		C_BILLING	BADDEBT	(0)	-	-	-	-	-	(0)	-	-	-
		NP	SNP	(4,484,072)	(1,735,244)	(1,351,028)	(1,280,793)	(13,963)	-	(12,268)	(83,372)	(7,404)	-
		PT	SG	(289,190)	(181,080)	(108,110)	-	-	-	-	-	-	-
		D_SPLIT	CIAC	(5,572,344)	-	-	(5,279,942)	(64,311)	-	-	(228,091)	-	-
		LABOR	SO	(1,218,558)	(495,756)	(92,963)	(437,072)	(6,998)	-	(71,288)	(75,218)	(39,262)	-

		D	SNPD	-	-	-	-	-	-	-	-	-	-
		CSS_SYS	CN	3,715	-	-	-	-	-	1,647	867	1,201	-
		P	SGCT	-	-	-	-	-	-	-	-	-	-
		BOOKDEPR	SCHMDEXP	(65,230,979)	(43,657,551)	(8,804,824)	(12,136,930)	(171,847)	-	(60,921)	(398,904)	-	-
		P	TROJD	(0)	(0)	-	-	-	-	-	-	-	-
		IBT	IBT	-	-	-	-	-	-	-	-	-	-
		P	SG	(151,206)	(151,206)	-	-	-	-	-	-	-	-
		GP	GPS	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				(98,423,188)	(55,973,287)	(15,263,838)	(25,354,440)	(333,801)	-	(257,194)	(1,120,189)	(120,438)	-
TOTAL DEFERRED INCOME TAXES				12,660,019	10,316,399	8,177,502	(5,882,254)	(268,741)	-	406,528	(390,854)	301,439	-
SCHMAF	Additions - Flow Through												
		SCHMAF	S	-	-	-	-	-	-	-	-	-	-
		SCHMAF	SNP	-	-	-	-	-	-	-	-	-	-
		SCHMAF	SO	-	-	-	-	-	-	-	-	-	-
		SCHMAF	SE	-	-	-	-	-	-	-	-	-	-
		P	TROJP	-	-	-	-	-	-	-	-	-	-
		SCHMAF	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
SCHMAP	Additions - Permanent												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SE	11,270	11,270	-	-	-	-	-	-	-	-
		PTD	SNP	-	-	-	-	-	-	-	-	-	-
		SCHMAP-SO	SO	794,541	600,654	24,937	117,242	1,877	-	19,123	20,177	10,532	-
		SCHMAP	SG	-	-	-	-	-	-	-	-	-	-
		BOOKDEPR	SCHMDEXP	29,259	19,583	3,949	5,444	77	-	27	179	-	-
				835,071	631,507	28,886	122,686	1,954	-	19,150	20,356	10,532	-
SCHMAT	Additions - Temporary												
		SCHMAT-SITUS	S	15,340,473	15,425,597	(70,870)	(30,667)	690	-	7,031	4,821	3,872	-
		SCHMAT-SG	GPS	-	-	-	-	-	-	-	-	-	-
		D_SPLIT	CIAC	22,664,151	-	-	21,474,876	261,569	-	-	927,706	-	-
		SCHMAT-SNP	SNP	18,237,871	8,434,033	4,880,163	4,766,173	-	-	395	156,837	269	-
		P	TROJD	0	0	-	-	-	-	-	-	-	-
		C_BILLING	BADDEBT	0	-	-	-	-	-	0	-	-	-
		SCHMAT-SE	SE	4,243,195	4,238,254	636	2,988	48	-	487	514	268	-
		SCHMAT-SG	GPS	-	-	-	-	-	-	-	-	-	-
		CSS_SYS	CN	(15,111)	-	-	-	-	-	(6,699)	(3,526)	(4,886)	-
		SCHMAT-SO	SO	4,956,187	2,011,392	361,020	1,786,382	28,976	-	295,172	310,678	162,568	-
		SCHMAT-SNP	SNPD	(0)	(0)	(0)	(0)	-	-	(0)	(0)	(0)	-
		P	SGCT	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		BOOKDEPR	SCHMDEXP	265,311,099	177,566,445	35,811,476	49,364,005	698,946	-	247,782	1,622,445	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	1,809,483	1,809,483	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				332,547,348	209,485,203	40,982,425	77,363,758	990,229	-	544,168	3,019,475	162,091	-
TOTAL SCHEDULE - M ADDITIONS				333,382,419	210,116,710	41,011,311	77,486,444	992,183	-	563,317	3,039,831	172,623	-
SCHMDF	Deductions - Flow Through												
		SCHMDF	S	-	-	-	-	-	-	-	-	-	-
		SCHMDF	SG	-	-	-	-	-	-	-	-	-	-
		SCHMDF	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
SCHMDP	Deductions - Permanent												
		SCHMDP	S	-	-	-	-	-	-	-	-	-	-
		P	SE	276,091	276,091	-	-	-	-	-	-	-	-
		SCHMDP	SNP	27,630	27,379	125	122	-	-	-	4	-	-
		BOOKDEPR	SCHMDEXP	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		SCHMDP-SO	SO	-	-	-	-	-	-	-	-	-	-
				303,721	303,470	125	122	-	-	-	4	-	-
SCHMDT	Deductions - Temporary												
		SCHMDT-SITUS	S	1,645,989	1,800,312	(39,678)	(97,892)	(558)	-	(5,944)	(6,945)	(3,306)	-
		SCHMDT	BADDEBT	-	-	-	-	-	-	-	-	-	-
		SCHMDT-SNP	SNP	30,203,376	13,970,129	8,081,434	7,892,413	-	-	-	259,400	-	-
		SCHMDT	CN	-	-	-	-	-	-	-	-	-	-
		SCHMDT-SG	SG	541,305	541,195	110	-	-	-	-	-	-	-
		SCHMDT-SG	SG	36,247,278	36,239,911	7,367	-	-	-	-	-	-	-
		P	SE	38,359	38,359	-	-	-	-	-	-	-	-
		SCHMDT-SG	SG	-	-	-	-	-	-	-	-	-	-
		SCHMDT-GPS	GPS	13,305,510	6,154,269	3,560,119	3,476,849	-	-	-	114,273	-	-
		SCHMDT-SO	SO	7,315,999	2,591,587	(1,646,815)	3,189,141	119,182	-	1,212,146	1,183,411	667,349	-
		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	-	-	-	-	-	-	-	-	-	-
				451,803,847	286,842,910	78,303,483	77,857,530	191,073	-	3,311,427	3,257,945	2,039,479	-
TOTAL SCHEDULE - M DEDUCTIONS				452,107,568	287,146,380	78,303,607	77,857,652	191,073	-	3,311,427	3,257,949	2,039,479	-
TOTAL SCHEDULE - M ADJUSTMENTS				(118,725,149)	(77,029,670)	(37,292,296)	(371,208)	801,110	-	(2,748,109)	(218,118)	(1,866,856)	-
40911	State Income Taxes												
		REVREQ		(1,615,210)	(942,660)	(219,914)	(400,202)	(3,159)	-	(17,462)	(20,944)	(10,869)	-
		REVREQ	S	5,845,636	3,411,599	795,895	1,448,380	11,431	-	63,197	75,800	39,334	-
	PTC	P	SG	-	-	-	-	-	-	-	-	-	-
		IBT	IBT	-	-	-	-	-	-	-	-	-	-
TOTAL STATE TAXES				4,230,426	2,468,939	575,981	1,048,177	8,273	-	45,735	54,856	28,466	-
Calculation of Taxable Income:													
	Operating Revenues			1,422,789,617	830,360,932	193,715,609	352,526,128	2,782,247	-	15,381,774	18,449,194	9,573,734	-
	Operating Deductions:												
	O & M Expenses			861,542,561	612,610,337	67,304,687	153,724,852	1,067,470	-	11,596,676	8,054,679	7,183,862	-
	Depreciation Expense			287,994,295	184,502,530	40,225,922	58,597,189	829,712	-	550,435	2,988,279	300,228	-
	Amortization Expense			43,237,301	5,795,483	1,660,641	29,375,575	45,969	-	2,363,170	2,356,565	1,639,897	-
	Taxes Other Than Income			84,171,808	24,456,422	12,622,760	45,488,639	196,642	-	321,645	876,129	209,570	-
	Interest & Dividends (AFUDC-Equity)			(21,356,078)	(9,100,725)	(5,127,508)	(6,499,315)	(80,130)	-	(119,505)	(350,552)	(78,343)	-
	Misc Revenue & Expense			3,165	(507,960)	(208)	511,333	-	-	-	-	-	-
	Total Operating Deductions			1,255,593,052	817,756,088	116,686,293	281,198,273	2,059,664	-	14,712,421	13,925,100	9,255,214	-
	Other Deductions:												
	Interest Deductions			84,048,729	32,525,127	25,323,444	24,006,986	261,721	-	229,959	1,562,708	138,784	-
	Interest on PCRBS			-	-	-	-	1	-	-	-	-	-
	Schedule M Adjustments			(118,725,149)	(77,029,670)	(37,292,296)	(371,208)	801,110	-	(2,748,109)	(218,118)	(1,866,856)	-
	Income Before State Taxes			(35,577,313)	(96,949,953)	14,413,575	46,949,660	1,261,971	-	(2,308,715)	2,743,267	(1,687,120)	-

	State Income Taxes			4,230,426	2,468,939	575,981	1,048,177	8,273	-	45,735	54,856	28,466	-
Total Taxable Income				(39,807,739)	(99,418,892)	13,837,595	45,901,483	1,253,699	-	(2,354,450)	2,688,411	(1,715,586)	-
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				(8,359,625.19)	(20,877,967)	2,905,895	9,639,311	263,277	-	(494,435)	564,566	(360,273)	-
Adjustments to Calculated Tax:													
40910	PMI	P	SE	(4,262)	(4,262)	-	-	-	-	-	-	-	-
40910	Renewable Energy Cre	P	SG	(52,932,259)	(52,932,259)	-	-	-	-	-	-	-	-
40910		P	SO	-	-	-	-	-	-	-	-	-	-
40910		P	S	-	-	-	-	-	-	-	-	-	-
Federal Income Tax				(61,296,146)	(73,814,488)	2,905,895	9,639,311	263,277	-	(494,435)	564,566	(360,273)	-
TOTAL OPERATING EXPENSES				**1,232,543,429**	**765,827,662**	**133,473,180**	**292,502,823**	**2,142,601**	**-**	**14,789,754**	**14,504,220**	**9,303,189**	**-**
310	Land and Land Rights												
		P	SG	606,665	606,665	-	-	-	-	-	-	-	-
		P	SG	8,821,544	8,821,544	-	-	-	-	-	-	-	-
		P	SG	14,127,229	14,127,229	-	-	-	-	-	-	-	-
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SG	330,272	330,272	-	-	-	-	-	-	-	-
				23,885,710	23,885,710	-	-	-	-	-	-	-	-
311	Structures and Improvements												
		P	SG	58,997,716	58,997,716	-	-	-	-	-	-	-	-
		P	SG	81,647,008	81,647,008	-	-	-	-	-	-	-	-
		P	SG	119,488,091	119,488,091	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				260,132,815	260,132,815	-	-	-	-	-	-	-	-
312	Boiler Plant Equipment												
		P	SG	152,960,616	152,960,616	-	-	-	-	-	-	-	-
		P	SG	121,218,558	121,218,558	-	-	-	-	-	-	-	-
		P	SG	872,591,337	872,591,337	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				1,146,770,511	1,146,770,511	-	-	-	-	-	-	-	-
314	Turbogenerator Units												
		P	SG	28,423,848	28,423,848	-	-	-	-	-	-	-	-
		P	SG	28,456,627	28,456,627	-	-	-	-	-	-	-	-
		P	SG	189,633,289	189,633,289	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				246,513,764	246,513,764	-	-	-	-	-	-	-	-
315	Accessory Electric Equipment												
		P	SG	22,358,913	22,358,913	-	-	-	-	-	-	-	-
		P	SG	34,705,893	34,705,893	-	-	-	-	-	-	-	-
		P	SG	53,367,895	53,367,895	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				110,432,701	110,432,701	-	-	-	-	-	-	-	-
316	Misc Power Plant Equipment												
		P	SG	612,221	612,221	-	-	-	-	-	-	-	-
		P	SG	1,280,790	1,280,790	-	-	-	-	-	-	-	-
		P	SG	6,188,421	6,188,421	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				8,081,432	8,081,432	-	-	-	-	-	-	-	-
317	Steam Plant ARO												
		P	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
SP	Unclassified Steam Plant - Account 300												
		P	SG	14,918,787	14,918,787	-	-	-	-	-	-	-	-
				14,918,787	14,918,787	-	-	-	-	-	-	-	-
Total Steam Production Plant				**1,810,735,721**	**1,810,735,721**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
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	2,693,685	2,693,685	-	-	-	-	-	-	-	-
		P	SG	1,373,470	1,373,470	-	-	-	-	-	-	-	-
		P	SG	5,726,355	5,726,355	-	-	-	-	-	-	-	-
		P	SG	343,282	343,282	-	-	-	-	-	-	-	-

				10,136,791	10,136,791	-	-	-	-	-	-	-	-
331	Structures and Improvements												
		P	SG	5,060,100	5,060,100	-	-	-	-	-	-	-	-
		P	SG	1,263,613	1,263,613	-	-	-	-	-	-	-	-
		P	SG	65,117,786	65,117,786	-	-	-	-	-	-	-	-
		P	SG	3,737,061	3,737,061	-	-	-	-	-	-	-	-
				75,178,560	75,178,560	-	-	-	-	-	-	-	-
332	Reservoirs, Dams & Waterways												
		P	SG	37,849,549	37,849,549	-	-	-	-	-	-	-	-
		P	SG	4,894,917	4,894,917	-	-	-	-	-	-	-	-
		P	SG	96,849,122	96,849,122	-	-	-	-	-	-	-	-
		P	SG	28,658,706	28,658,706	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				168,252,294	168,252,294	-	-	-	-	-	-	-	-
333	Water Wheel, Turbines, & Generators												
		P	SG	7,486,873	7,486,873	-	-	-	-	-	-	-	-
		P	SG	1,759,686	1,759,686	-	-	-	-	-	-	-	-
		P	SG	17,520,566	17,520,566	-	-	-	-	-	-	-	-
		P	SG	11,357,815	11,357,815	-	-	-	-	-	-	-	-
				38,124,941	38,124,941	-	-	-	-	-	-	-	-
334	Accessory Electric Equipment												
		P	SG	952,406	952,406	-	-	-	-	-	-	-	-
		P	SG	869,681	869,681	-	-	-	-	-	-	-	-
		P	SG	17,687,603	17,687,603	-	-	-	-	-	-	-	-
		P	SG	2,919,246	2,919,246	-	-	-	-	-	-	-	-
				22,428,936	22,428,936	-	-	-	-	-	-	-	-
335	Misc. Power Plant Equipment												
		P	SG	294,516	294,516	-	-	-	-	-	-	-	-
		P	SG	40,146	40,146	-	-	-	-	-	-	-	-
		P	SG	328,991	328,991	-	-	-	-	-	-	-	-
		P	SG	4,765	4,765	-	-	-	-	-	-	-	-
				668,419	668,419	-	-	-	-	-	-	-	-
336	Roads, Railroads & Bridges												
		P	SG	1,137,566	1,137,566	-	-	-	-	-	-	-	-
		P	SG	191,461	191,461	-	-	-	-	-	-	-	-
		P	SG	4,912,613	4,912,613	-	-	-	-	-	-	-	-
		P	SG	608,333	608,333	-	-	-	-	-	-	-	-
				6,849,973	6,849,973	-	-	-	-	-	-	-	-
337	Hydro Plant ARO												
		P	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
HP	Unclassified Hydro Plant - Acct 300												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
Total Hydraulic Plant				**321,639,915**	**321,639,915**	-	-	-	-	-	-	-	-
340	Land and Land Rights												
		P	S	74,986	74,986	-	-	-	-	-	-	-	-
		P	SG	10,173,300	10,173,300	-	-	-	-	-	-	-	-
		P	SG	3,070,758	3,070,758	-	-	-	-	-	-	-	-
		P	SG	61,299	61,299	-	-	-	-	-	-	-	-
				13,380,343	13,380,343	-	-	-	-	-	-	-	-
341	Structures and Improvements												
		P	SG	43,480,558	43,480,558	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	24,934,945	24,934,945	-	-	-	-	-	-	-	-
		P	SG	1,113,986	1,113,986	-	-	-	-	-	-	-	-
				69,529,489	69,529,489	-	-	-	-	-	-	-	-
342	Fuel Holders, Producers & Accessories												
		P	SG	3,551,616	3,551,616	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	719,368	719,368	-	-	-	-	-	-	-	-
				4,270,984	4,270,984	-	-	-	-	-	-	-	-
343	Prime Movers												
		P	S	315,315	315,315	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	762,265,075	762,265,075	-	-	-	-	-	-	-	-
		P	SG	244,208,406	244,208,406	-	-	-	-	-	-	-	-
		P	SG	15,100,889	15,100,889	-	-	-	-	-	-	-	-
				1,021,889,685	1,021,889,685	-	-	-	-	-	-	-	-
344	Generators												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SG	42,308,381	42,308,381	-	-	-	-	-	-	-	-
		P	SG	103,902,925	103,902,925	-	-	-	-	-	-	-	-
		P	SG	4,636,027	4,636,027	-	-	-	-	-	-	-	-
				150,847,332	150,847,332	-	-	-	-	-	-	-	-
345	Accessory Electric Plant												
		P	SG	51,834,382	51,834,382	-	-	-	-	-	-	-	-
		P	SG	61,779,677	61,779,677	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	756,429	756,429	-	-	-	-	-	-	-	-
				114,370,488	114,370,488	-	-	-	-	-	-	-	-
346	Misc. Power Plant Equipment												
		P	SG	3,117,681	3,117,681	-	-	-	-	-	-	-	-
		P	SG	2,854,884	2,854,884	-	-	-	-	-	-	-	-
				5,972,566	5,972,566	-	-	-	-	-	-	-	-
347	Other Production ARO												
		P	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
OP	Unclassified Other Prod Plant-Acct 300												
		P	S	-	-	-	-	-	-	-	-	-	-

		P	SG	(144,214)	(144,214)	-	-	-	-	-	-	-	-
				(144,214)	(144,214)	-	-	-	-	-	-	-	-
Total Other Production Plant				**1,380,116,672**	**1,380,116,672**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Experimental Plant													
103	Experimental Plant												
		P	SG	-	-	-	-	-	-	-	-	-	-
Total Experimental Plant				**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
TOTAL PRODUCTION PLANT				**3,512,492,308**	**3,512,492,308**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
350	Land and Land Rights												
		T	SG	5,470,988	-	5,470,988	-	-	-	-	-	-	-
		T	SG	12,300,087	-	12,300,087	-	-	-	-	-	-	-
		T	SG	63,014,302	-	63,014,302	-	-	-	-	-	-	-
				80,785,377	-	80,785,377	-	-	-	-	-	-	-
352	Structures and Improvements												
		T	S	-	-	-	-	-	-	-	-	-	-
		T	SG	1,811,625	-	1,811,625	-	-	-	-	-	-	-
		T	SG	4,607,410	-	4,607,410	-	-	-	-	-	-	-
		T	SG	75,127,254	-	75,127,254	-	-	-	-	-	-	-
				81,546,289	-	81,546,289	-	-	-	-	-	-	-
353	Station Equipment												
		STEP_UP	SG	27,253,570	1,916,294	25,337,276	-	-	-	-	-	-	-
		STEP_UP	SG	39,679,893	2,790,033	36,889,860	-	-	-	-	-	-	-
		STEP_UP	SG	543,548,929	38,218,838	505,330,091	-	-	-	-	-	-	-
				610,482,392	42,925,165	567,557,227	-	-	-	-	-	-	-
354	Towers and Fixtures												
		T	SG	33,397,707	-	33,397,707	-	-	-	-	-	-	-
		T	SG	34,209,839	-	34,209,839	-	-	-	-	-	-	-
		T	SG	280,025,120	-	280,025,120	-	-	-	-	-	-	-
				347,632,667	-	347,632,667	-	-	-	-	-	-	-
355	Poles and Fixtures												
		T	S	-	-	-	-	-	-	-	-	-	-
		T	SG	15,608,667	-	15,608,667	-	-	-	-	-	-	-
		T	SG	29,621,536	-	29,621,536	-	-	-	-	-	-	-
		T	SG	324,275,026	-	324,275,026	-	-	-	-	-	-	-
				369,505,228	-	369,505,228	-	-	-	-	-	-	-
356	Clearing and Grading												
		T	SG	41,055,979	-	41,055,979	-	-	-	-	-	-	-
		T	SG	40,970,698	-	40,970,698	-	-	-	-	-	-	-
		T	SG	277,503,823	-	277,503,823	-	-	-	-	-	-	-
				359,530,500	-	359,530,500	-	-	-	-	-	-	-
357	Underground Conduit												
		T	SG	1,661	-	1,661	-	-	-	-	-	-	-
		T	SG	23,894	-	23,894	-	-	-	-	-	-	-
		T	SG	980,230	-	980,230	-	-	-	-	-	-	-
				1,005,785	-	1,005,785	-	-	-	-	-	-	-
358	Underground Conductors												
		T	SG	-	-	-	-	-	-	-	-	-	-
		T	SG	283,529	-	283,529	-	-	-	-	-	-	-
		T	SG	2,083,819	-	2,083,819	-	-	-	-	-	-	-
				2,367,348	-	2,367,348	-	-	-	-	-	-	-
359	Roads and Trails												
		T	SG	485,699	-	485,699	-	-	-	-	-	-	-
		T	SG	114,843	-	114,843	-	-	-	-	-	-	-
		T	SG	2,565,965	-	2,565,965	-	-	-	-	-	-	-
				3,166,507	-	3,166,507	-	-	-	-	-	-	-
TP	Unclassified Trans Plant - Acct 300												
		T	SG	241,036,512	-	241,036,512	-	-	-	-	-	-	-
				241,036,512	-	241,036,512	-	-	-	-	-	-	-
TS0	Unclassified Trans Sub Plant - Acct 300												
		T	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
TOTAL TRANSMISSION PLANT				**2,097,058,605**	**42,925,165**	**2,054,133,440**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
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	87	55	32	-	-	-	-	-	-	-
		G-SG	SG	320	132	188	-	-	-	-	-	-	-
		LABOR	SO	2,068,311	841,468	157,791	741,861	11,878	-	121,000	127,671	66,641	-
				8,534,997	841,655	158,011	6,537,458	82,470	-	348,826	378,038	188,539	-
390	Structures and Improvements												
		D_SPLIT	S	40,901,786	-	-	38,755,513	472,051	-	-	1,674,222	-	-
		P	SE	222,614	222,614	-	-	-	-	-	-	-	-
		G-DGP	SG	87,398	55,368	32,030	-	-	-	-	-	-	-
		G-DGU	SG	353,615	224,022	129,593	-	-	-	-	-	-	-
		B_Center	CN	2,543,565	-	-	-	-	-	1,656,995	-	886,570	-
		G-SG	SG	2,709,338	1,114,891	1,594,448	-	-	-	-	-	-	-
		LABOR	SO	27,551,225	11,208,897	2,101,874	9,882,066	158,227	-	1,611,796	1,700,659	887,707	-
				74,369,541	12,825,791	3,857,945	48,637,579	630,278	-	3,268,791	3,374,882	1,774,277	-
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	1,072,760	441,440	631,320	-	-	-	-	-	-	-
		P	SE	8,010	8,010	-	-	-	-	-	-	-	-
		LABOR	SO	16,512,388	6,717,874	1,259,725	5,922,659	94,831	-	966,004	1,019,263	532,033	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	1,053	1,053	-	-	-	-	-	-	-	-
				21,246,980	7,168,377	1,891,045	8,200,880	122,580	-	1,779,257	1,117,681	967,161	-
392	Transportation Equipment												
		D_SPLIT	S	26,003,370	-	-	24,638,873	300,107	-	-	1,064,389	-	-
		LABOR	SO	2,109,964	858,414	160,968	756,801	12,118	-	123,437	130,242	67,984	-
		G-SG	SG	6,134,374	2,524,290	3,610,084	-	-	-	-	-	-	-
		B_Center	CN	-	-	-	-	-	-	-	-	-	-
		G-DGU	SG	104,592	66,261	38,331	-	-	-	-	-	-	-
		P	SE	82,063	82,063	-	-	-	-	-	-	-	-
		G-DGP	SG	18,410	11,663	6,747	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	11,642	11,642	-	-	-	-	-	-	-	-
				34,464,413	3,554,333	3,816,130	25,395,674	312,225	-	123,437	1,194,631	67,984	-
393	Stores Equipment												
		D_SPLIT	S	2,735,814	-	-	2,592,255	31,574	-	-	111,984	-	-
		G-DGP	SG	-	-	-	-	-	-	-	-	-	-
		G-DGU	SG	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	67,548	27,481	5,153	24,228	388	-	3,952	4,170	2,176	-
		G-SG	SG	1,566,389	644,568	921,821	-	-	-	-	-	-	-
		P	SG	14,070	14,070	-	-	-	-	-	-	-	-
				4,383,821	686,120	926,975	2,616,483	31,962	-	3,952	116,154	2,176	-
394	Tools, Shop & Garage Equipment												
		D_SPLIT	S	10,914,668	-	-	10,341,934	125,967	-	-	446,767	-	-
		G-DGP	SG	9,824	6,224	3,600	-	-	-	-	-	-	-
		G-SG	SG	5,654,511	2,326,827	3,327,685	-	-	-	-	-	-	-
		LABOR	SO	532,529	216,653	40,626	191,007	3,058	-	31,154	32,872	17,158	-
		P	SE	31,508	31,508	-	-	-	-	-	-	-	-
		G-SG	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	23,441	23,441	-	-	-	-	-	-	-	-
				17,166,482	2,604,653	3,371,911	10,532,941	129,025	-	31,154	479,639	17,158	-
395	Laboratory Equipment												
		D_SPLIT	S	9,565,368	-	-	9,063,437	110,395	-	-	391,537	-	-
		G-DGP	SG	-	-	-	-	-	-	-	-	-	-
		G-DGU	SG	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	1,324,126	538,705	101,017	474,937	7,604	-	77,464	81,735	42,664	-
		P	SE	336,723	336,723	-	-	-	-	-	-	-	-
		G-SG	SG	1,680,922	691,698	989,224	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	3,655	3,655	-	-	-	-	-	-	-	-
				12,910,795	1,570,782	1,090,241	9,538,374	117,999	-	77,464	473,271	42,664	-
396	Power Operated Equipment												
		D_SPLIT	S	44,851,927	-	-	42,498,374	517,640	-	-	1,835,912	-	-
		G-DGP	SG	68,304	43,272	25,032	-	-	-	-	-	-	-
		G-SG	SG	11,773,951	4,844,971	6,928,980	-	-	-	-	-	-	-
		LABOR	SO	2,265,084	921,523	172,803	812,440	13,008	-	132,511	139,817	72,982	-
		G-DGU	SG	241,105	152,745	88,361	-	-	-	-	-	-	-
		P	SE	59,333	59,333	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				59,259,704	6,021,844	7,215,175	43,310,814	530,648	-	132,511	1,975,729	72,982	-
397	Communication Equipment												

		D_SPLIT	S	99,466,592	-	-	94,247,199	1,147,953	-	-	4,071,440	-	-
		G-DGP	SG	78,674	49,842	28,833	-	-	-	-	-	-	-
		G-DGU	SG	36,305	23,000	13,305	-	-	-	-	-	-	-
		LABOR	SO	40,735,572	16,572,795	3,107,704	14,611,024	233,944	-	2,383,103	2,514,492	1,312,509	-
		B_Center	CN	638,025	-	-	-	-	-	415,639	-	222,386	-
		G-SG	SG	49,708,355	20,454,948	29,253,407	-	-	-	-	-	-	-
		P	SE	23,469	23,469	-	-	-	-	-	-	-	-
		G-SG	SG	-	-	-	-	-	-	-	-	-	-
		G-SG	SG	4,336	1,784	2,552	-	-	-	-	-	-	-
				190,691,327	37,125,838	32,405,800	108,858,222	1,381,897	-	2,798,742	6,585,932	1,534,895	-
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	605,636	246,396	46,204	217,229	3,478	-	35,431	37,384	19,514	-
		P	SE	994	994	-	-	-	-	-	-	-	-
		G-SG	SG	748,766	308,117	440,649	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				2,606,087	555,507	486,853	1,378,067	17,617	-	52,086	87,532	28,425	-
399	Coal Mine												
		P	SE	12,719,998	12,719,998	-	-	-	-	-	-	-	-
MP	Unckassified Mine Plant	P	SE	-	-	-	-	-	-	-	-	-	-
				12,719,998	12,719,998	-	-	-	-	-	-	-	-
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	2,575,971	2,575,971	-	-	-	-	-	-	-	-
		LABOR	SO	-	-	-	-	-	-	-	-	-	-
				4,188,634	2,575,971	-	1,528,041	18,612	-	-	66,011	-	-
	Remove Capital Leases			(4,188,634)	(2,575,971)	-	(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	16,747,258	6,813,428	1,277,643	6,006,902	96,179	-	979,744	1,033,761	539,600	-
		B_Center	CN	-	-	-	-	-	-	-	-	-	-
		G-SG	SG	-	-	-	-	-	-	-	-	-	-
		G-DGP	SG	-	-	-	-	-	-	-	-	-	-
		G-DGU	SG	-	-	-	-	-	-	-	-	-	-
				16,747,258	6,813,428	1,277,643	6,006,902	96,179	-	979,744	1,033,761	539,600	-
399G	Unclassified Gen Plant - Acct 300												
		D_SPLIT	S	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	-	-	-	-	-	-	-	-	-	-
		G-SG	SG	-	-	-	-	-	-	-	-	-	-
		G-DGP	SG	-	-	-	-	-	-	-	-	-	-
		G-DGU	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
TOTAL GENERAL PLANT				**455,101,404**	**92,488,325**	**56,497,729**	**271,013,394**	**3,452,882**	**-**	**9,595,963**	**16,817,251**	**5,235,861**	**-**
301	Organization												
		D_SPLIT	S	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	-	-	-	-	-	-	-	-	-	-
		I-SG	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
302	Franchise & Consent												
		D_SPLIT	S	-	-	-	-	-	-	-	-	-	-
		I-SG	SG	3,135,517	2,058,991	1,073,959	2,485	-	-	-	82	-	-
		I-DGP	SG	46,270,384	46,270,384	-	-	-	-	-	-	-	-
		I-DGU	SG	2,540,901	2,540,901	-	-	-	-	-	-	-	-
		I-DGP	SG	-	-	-	-	-	-	-	-	-	-
		I-DGU	SG	124,511	124,511	-	-	-	-	-	-	-	-
				52,071,314	50,994,788	1,073,959	2,485	-	-	-	82	-	-
303	Miscellaneous Intangible Plant												
		D_SPLIT	S	4,609,463	-	-	4,367,587	53,198	-	-	188,678	-	-
		LABOR	SG	51,495,028	20,950,156	3,928,539	18,470,222	295,736	-	3,012,551	3,178,643	1,659,181	-
		LABOR	SO	129,558,166	52,709,239	9,883,951	46,469,887	744,052	-	7,579,383	7,997,261	4,174,393	-
		P	SE	(16,125)	(16,125)	-	-	-	-	-	-	-	-
		CSS_SYS	CN	66,204,803	-	-	-	-	-	29,350,796	15,447,787	21,406,220	-
		I-DGP	SG	-	-	-	-	-	-	-	-	-	-
		I-DGP	SG	-	-	-	-	-	-	-	-	-	-
				251,851,335	73,643,270	13,812,490	69,307,696	1,092,986	-	39,942,730	26,812,369	27,239,794	-
303	Less Non-Utility Plant												
		I-SITUS	S	-	-	-	-	-	-	-	-	-	-
				251,851,335	73,643,270	13,812,490	69,307,696	1,092,986	-	39,942,730	26,812,369	27,239,794	-
IP	Unclassified Intangible Plant - Acct 300												
		D_SPLIT	S	-	-	-	-	-	-	-	-	-	-
		I-SG	SG	-	-	-	-	-	-	-	-	-	-
		I-DGU	SG	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
TOTAL INTANGIBLE PLANT				**303,922,649**	**124,638,057**	**14,886,449**	**69,310,181**	**1,092,986**	**-**	**39,942,730**	**26,812,451**	**27,239,794**	**-**
TOTAL ELECTRIC PLANT IN SERVICE				**8,852,783,093**	**3,772,543,856**	**2,125,517,618**	**2,694,175,792**	**33,216,336**	**-**	**49,538,693**	**145,315,143**	**32,475,655**	**-**
105	Plant Held For Future Use												
		D_SPLIT	S	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		T	SG	437,959	-	437,959	-	-	-	-	-	-	-
		P	SG	2,326,335	2,326,335	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
		G	SG	(2,764,295)	(563,907)	(1,000,494)	(1,126,001)	-	-	(36,884)	(37,008)	-	-

				-	1,762,429	(562,535)	(1,126,001)	-	-	(36,884)	(37,008)	-	-
114	Electric Plant Acquisition Adjustments												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SG	917,274	917,274	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				917,274	917,274	-	-	-	-	-	-	-	-
115	Accum Provision for Asset Acquisition Adjustments												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SG	(215,669)	(215,669)	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				(215,669)	(215,669)	-	-	-	-	-	-	-	-
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	44,556,924	44,556,924	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
				44,556,924	44,556,924	-	-	-	-	-	-	-	-
152	Fuel Stock - Undistributed												
		P	SE	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
25316	DG&T Working Capital Deposit												
		P	SE	(702,660)	(702,660)	-	-	-	-	-	-	-	-
				(702,660)	(702,660)	-	-	-	-	-	-	-	-
25317	DG&T Working Capital Deposit												
		P	SE	(662,138)	(662,138)	-	-	-	-	-	-	-	-
				(662,138)	(662,138)	-	-	-	-	-	-	-	-
25319	Provo Working Capital Deposit												
		P	SE	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
	Total Fuel Stock			43,192,126	43,192,126	-	-	-	-	-	-	-	-
154	Materials and Supplies												
		MSS	S	49,096,450	40,104,956	726,333	8,002,154	-	-	-	263,007	-	-
		MSS	SG	(131,544)	(107,453)	(1,946)	(21,440)	-	-	-	(705)	-	-
		MSS	SE	-	-	-	-	-	-	-	-	-	-
		MSS	SO	(348,970)	(285,060)	(5,163)	(56,878)	-	-	-	(1,869)	-	-
		MSS	SG	31,321,653	25,585,425	463,373	5,105,068	-	-	-	167,788	-	-
		MSS	SG	2,074	1,694	31	338	-	-	-	11	-	-
		MSS	SNPD	(346,469)	(283,017)	(5,126)	(56,470)	-	-	-	(1,856)	-	-
		MSS	SG	-	-	-	-	-	-	-	-	-	-
		MSS	SG	-	-	-	-	-	-	-	-	-	-
		MSS	SG	-	-	-	-	-	-	-	-	-	-
		MSS	SG	-	-	-	-	-	-	-	-	-	-
		MSS	SG	2,197,788	1,795,286	32,514	358,214	-	-	-	11,773	-	-
		MSS	SG	-	-	-	-	-	-	-	-	-	-
				81,790,983	66,811,832	1,210,017	13,330,985	-	-	-	438,149	-	-
163	Stores Expense Undistributed												
		MSS	SO	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
25318	Provo Working Capital Deposit												
		MSS	SG	(71,172)	(58,138)	(1,053)	(11,600)	-	-	-	(381)	-	-
				(71,172)	(58,138)	(1,053)	(11,600)	-	-	-	(381)	-	-
	Total Materials & Supplies			81,719,811	66,753,694	1,208,964	13,319,385	-	-	-	437,768	-	-
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	43,521	18,546	10,449	13,245	163	-	244	714	160	-
		PT	SG	999,612	625,920	373,692	-	-	-	-	-	-	-
		P	SE	11,465	11,465	-	-	-	-	-	-	-	-
		LABOR	SO	5,997,840	2,440,152	457,573	2,151,304	34,446	-	350,884	370,230	193,252	-
				11,129,917	4,754,958	1,152,784	3,627,057	58,026	-	589,668	622,635	324,789	-
182M	Misc Regulatory Assets												
		DDS2	S	-	-	-	-	-	-	-	-	-	-
		DEFSG	SG	611,240	560,054	51,186	-	-	-	-	-	-	-
		P	SGCT	-	-	-	-	-	-	-	-	-	-
		DEFSG	SG	-	-	-	-	-	-	-	-	-	-
		P	SE	28,858,211	28,858,211	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	12,446,039	5,063,527	949,504	4,464,142	71,478	-	728,115	768,259	401,014	-
				41,915,490	34,481,792	1,000,690	4,464,142	71,478	-	728,115	768,259	401,014	-
186M	Misc Deferred Debits												
		LABOR	S	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		DEFSG	SG	25,160,668	23,053,690	2,106,978	-	-	-	-	-	-	-

		LABOR	SO	21,299	8,665	1,625	7,640	122	-	1,246	1,315	686	-
		P	SE	202,872	202,872	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		GP	EXCTAX	-	-	-	-	-	-	-	-	-	-
				25,384,840	23,265,227	2,108,603	7,640	122	-	1,246	1,315	686	-
Working Capital													
CWC	Cash Working Capital												
		CWC	S	8,503,482	5,413,388	798,144	2,008,543	14,695	-	109,753	91,386	67,573	-
		CWC	SO	-	-	-	-	-	-	-	-	-	-
		CWC	SE	-	-	-	-	-	-	-	-	-	-
				8,503,482	5,413,388	798,144	2,008,543	14,695	-	109,753	91,386	67,573	-
OWC	Other Work. Cap.												
131	Cash	GP	SNP	-	-	-	-	-	-	-	-	-	-
135	Working Funds	GP	SG	-	-	-	-	-	-	-	-	-	-
141	Notes Receivable	GP	SO	-	-	-	-	-	-	-	-	-	-
143	Other A/R	LABOR	SO	10,498,734	4,271,288	800,945	3,765,683	60,294	-	614,195	648,057	338,272	-
232	A/P	LABOR	S	-	-	-	-	-	-	-	-	-	-
232	A/P	LABOR	SO	(1,672,721)	(680,527)	(127,611)	(599,971)	(9,606)	-	(97,857)	(103,252)	(53,895)	-
232	A/P	P	SE	(781,151)	(781,151)	-	-	-	-	-	-	-	-
232	A/P	P	SG	(868,492)	(868,492)	-	-	-	-	-	-	-	-
2533	Other Msc. Df. Crd.	P	S	-	-	-	-	-	-	-	-	-	-
2533	Other Msc. Df. Crd.	P	SE	(2,332,287)	(2,332,287)	-	-	-	-	-	-	-	-
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	-	-	-	-	-	-	-	-	-	-
				4,844,083	(391,169)	673,334	3,165,712	50,688	-	516,337	544,805	284,376	-
Total Working Capital				13,347,565	5,022,220	1,471,478	5,174,255	65,382	-	626,090	636,191	351,949	-
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	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
TOTAL MISCELLANEOUS RATE BASE				-	-	-	-	-	-	-	-	-	-
TOTAL RATE BASE ADDITIONS				**217,391,352**	**179,934,050**	**6,379,984**	**25,466,478**	**195,008**	**-**	**1,908,235**	**2,429,160**	**1,078,438**	**-**
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	(438,084)	(178,229)	(33,421)	(157,132)	(2,516)	-	(25,629)	(27,042)	(14,115)	-
2283	Prov for Pensions and Ben	LABOR	S	-	-	-	-	-	-	-	-	-	-
25335	Pens Oblig	LABOR	SE	(28,858,211)	(11,740,629)	(2,201,584)	(10,350,855)	(165,733)	-	(1,688,257)	(1,781,336)	(929,818)	-
254	Reg Liabilities - Insurance	LABOR	SO	(3,044,156)	(1,238,480)	(232,238)	(1,091,877)	(17,483)	-	(178,089)	(187,907)	(98,083)	-
				(23,819,237)	(9,690,581)	(1,817,162)	(8,543,477)	(136,794)	-	(1,393,468)	(1,470,294)	(767,461)	-
22841	Accum Misc Oper Provisions - Other												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SG	(61,227)	(61,227)	-	-	-	-	-	-	-	-
				(61,227)	(61,227)	-	-	-	-	-	-	-	-
254105	ARO	P	S	-	-	-	-	-	-	-	-	-	-
230	ARO	P	TROJD	(1,441,094)	(1,441,094)	-	-	-	-	-	-	-	-
254105	ARO	P	TROJD	-	-	-	-	-	-	-	-	-	-
254		P	S	(369,192,352)	(369,192,352)	-	-	-	-	-	-	-	-
				(370,633,446)	(370,633,446)	-	-	-	-	-	-	-	-
252	Customer Advances for Construction												
		D_SPLIT	S	(2,069,907)	-	-	(1,961,291)	(23,889)	-	-	(84,727)	-	-
		T	SE	-	-	-	-	-	-	-	-	-	-
		T	SG	(20,960,626)	-	(20,960,626)	-	-	-	-	-	-	-
		D_SPLIT	SO	-	-	-	-	-	-	-	-	-	-
		B_Center	CN	-	-	-	-	-	-	-	-	-	-
				(23,030,533)	-	(20,960,626)	(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	(16,645,479)	(16,645,479)	-	-	-	-	-	-	-	-
		P	SE	(3,659,474)	(3,659,474)	-	-	-	-	-	-	-	-
				(20,509,383)	(20,304,954)	-	(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	14,655,014	5,962,223	1,118,026	5,256,456	84,164	-	857,344	904,613	472,188	-
		P	GPS	-	-	-	-	-	-	-	-	-	-
		IBT	IBT	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		C_BILLING	BADDEBT	2,391,934	-	-	-	-	-	2,391,934	-	-	-
		P	TROJD	333,666	333,666	-	-	-	-	-	-	-	-
		P	SG	358,454	358,454	-	-	-	-	-	-	-	-
		P	SE	473,309	473,309	-	-	-	-	-	-	-	-
		LABOR	SNP	-	-	-	-	-	-	-	-	-	-
		D_SPLIT	SNPD	409,509	-	-	388,021	4,726	-	-	16,762	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				112,193,627	7,127,651	1,118,026	94,306,151	1,168,810	-	3,249,278	4,751,523	472,188	-

281	Accumulated Deferred Income Taxes												
		P	S	-	-	-	-	-	-	-	-	-	-
		PT	SG	(0)	(0)	(0)	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-	-
				(0)	(0)	(0)	-	-	-	-	-	-	-
282	Accumulated Deferred Income Taxes												
		GP	S	(741,897,489)	(316,153,777)	(178,126,603)	(225,782,359)	(2,783,658)	-	(4,151,534)	(12,177,971)	(2,721,586)	-
		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	(226,230)	-	-	-	-	-	-	-	(226,230)	-
		P	SG-U	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	(285,561)	(116,177)	(21,785)	(102,425)	(1,640)	-	(16,706)	(17,627)	(9,201)	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SE	(148,010)	(148,010)	-	-	-	-	-	-	-	-
		P	SG	1,388,143	1,388,143	-	-	-	-	-	-	-	-
				(741,265,083)	(315,076,917)	(178,172,075)	(225,907,964)	(2,785,298)	-	(4,169,122)	(12,196,091)	(2,957,617)	-
283	Accumulated Deferred Income Taxes												
		GP	S	(5,955,522)	(2,537,899)	(1,429,897)	(1,812,449)	(22,346)	-	(33,326)	(97,758)	(21,847)	-
		P	SG	(584,194)	(584,194)	-	-	-	-	-	-	-	-
		P	SE	129,198	129,198	-	-	-	-	-	-	-	-
		LABOR	SO	(5,500,684)	(2,237,889)	(419,645)	(1,972,984)	(31,590)	-	(321,800)	(339,542)	(177,233)	-
		GP	GPS	(2,320,754)	(988,971)	(557,204)	(706,277)	(8,708)	-	(12,987)	(38,094)	(8,513)	-
		LABOR	SNP	(176,775)	(71,919)	(13,486)	(63,406)	(1,015)	-	(10,342)	(10,912)	(5,696)	-
		P	TROJD	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SGCT	-	-	-	-	-	-	-	-	-	-
		IBT	IBT	-	-	-	-	-	-	-	-	-	-
				(14,408,731)	(6,291,674)	(2,420,232)	(4,555,116)	(63,659)	-	(378,454)	(486,306)	(213,290)	-
TOTAL ACCUMULATED DEF INCOME TAX				(643,480,187)	(314,240,940)	(179,474,281)	(136,156,929)	(1,680,147)	-	(1,298,298)	(7,930,873)	(2,698,719)	-
255	Accumulated Investment Tax Credit												
		LABOR	S	-	-	-	-	-	-	-	-	-	-
		LABOR	ITC84	-	-	-	-	-	-	-	-	-	-
		LABOR	ITC85	-	-	-	-	-	-	-	-	-	-
		LABOR	ITC86	-	-	-	-	-	-	-	-	-	-
		LABOR	ITC88	-	-	-	-	-	-	-	-	-	-
		LABOR	ITC89	-	-	-	-	-	-	-	-	-	-
		LABOR	ITC90	-	-	-	-	-	-	-	-	-	-
		LABOR	SG	(45,778)	(18,624)	(3,492)	(16,420)	(263)	-	(2,678)	(2,826)	(1,475)	-
				(45,778)	(18,624)	(3,492)	(16,420)	(263)	-	(2,678)	(2,826)	(1,475)	-
TOTAL RATE BASE DEDUCTIONS				**(1,081,579,791)**	**(714,949,771)**	**(202,255,561)**	**(146,871,819)**	**(1,843,452)**	**-**	**(2,694,444)**	**(9,497,088)**	**(3,467,655)**	**-**
108SP	Steam Prod Plant Accumulated Depr												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SG	(195,324,698)	(195,324,698)	-	-	-	-	-	-	-	-
		P	SG	(187,675,365)	(187,675,365)	-	-	-	-	-	-	-	-
		P	SG	(885,770,211)	(885,770,211)	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				(1,268,770,274)	(1,268,770,274)	-	-	-	-	-	-	-	-
108NP	Nuclear Prod Plant Accumulated Depr												
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
108HP	Hydraulic Prod Plant Accum Depr												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SG	(44,151,776)	(44,151,776)	-	-	-	-	-	-	-	-
		P	SG	(8,211,199)	(8,211,199)	-	-	-	-	-	-	-	-
		P	SG	(68,623,085)	(68,623,085)	-	-	-	-	-	-	-	-
		P	SG	(19,419,019)	(19,419,019)	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				(140,405,079)	(140,405,079)	-	-	-	-	-	-	-	-
108OP	Other Production Plant - Accum Depr												
		P	S	(183,195,467)	(183,195,467)	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	52,720,573	52,720,573	-	-	-	-	-	-	-	-
		P	SG	(148,624,309)	(148,624,309)	-	-	-	-	-	-	-	-
		P	SG	(11,428,672)	(11,428,672)	-	-	-	-	-	-	-	-
				(290,527,875)	(290,527,875)	-	-	-	-	-	-	-	-
108EP	Experimental Plant - Accum Depr												
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
TOTAL PRODUCTION PLANT DEPRECIATION				**(1,699,703,228)**	**(1,699,703,228)**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
108TP	Transmission Plant Accumulated Depr												
		T_Split	S	-	-	-	-	-	-	-	-	-	-
		T_Split	SG	(92,069,293)	(1,884,587)	(90,184,706)	-	-	-	-	-	-	-
		T_Split	SG	(111,265,118)	(2,277,511)	(108,987,607)	-	-	-	-	-	-	-
		T_Split	SG	(363,551,001)	(7,441,607)	(356,109,394)	-	-	-	-	-	-	-
TOTAL TRANS PLANT ACCUM DEPR				**(566,885,412)**	**(11,603,705)**	**(555,281,707)**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
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	(186,466)	(118,130)	(68,336)	-	-	-	-	-	-	-
		G-DGU	SG	(508,818)	(322,346)	(186,472)	-	-	-	-	-	-	-
		G-SG	SG	(36,230,166)	(14,908,684)	(21,321,482)	-	-	-	-	-	-	-
		B_Center	CN	(2,141,251)	-	-	-	-	-	(1,394,909)	-	(746,342)	-
		LABOR	SO	(34,259,759)	(13,938,186)	(2,613,666)	(12,288,281)	(196,754)	-	(2,004,257)	(2,114,758)	(1,103,857)	-
		P	SE	(374,616)	(374,616)	-	-	-	-	-	-	-	-
		G-SG	SG	(33,997)	(13,990)	(20,007)	-	-	-	-	-	-	-
		G-SG	SG	-	-	-	-	-	-	-	-	-	-
				(182,294,103)	(29,675,951)	(24,209,964)	(115,150,802)	(1,449,643)	-	(3,399,166)	(6,558,377)	(1,850,199)	-
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				**(182,294,103)**	**(29,675,951)**	**(24,209,964)**	**(115,150,802)**	**(1,449,643)**	**-**	**(3,399,166)**	**(6,558,377)**	**(1,850,199)**	**-**
TOTAL ACCUM DEPR - PLANT IN SERVICE				**(3,571,364,011)**	**(1,740,982,885)**	**(579,491,671)**	**(1,198,794,615)**	**(16,682,711)**	**-**	**(3,399,166)**	**(30,162,765)**	**(1,850,199)**	**-**
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	(363,384)	(147,839)	(27,722)	(130,339)	(2,087)	-	(21,259)	(22,431)	(11,708)	-
		P	SE	-	-	-	-	-	-	-	-	-	-
				(5,588,746)	(147,839)	(27,722)	(5,081,506)	(62,393)	-	(21,259)	(236,319)	(11,708)	-
111HP	Accum Prov for Amort-Hydro												
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	(940,299)	(940,299)	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-

				(940,299)	(940,299)	-	-	-	-	-	-	-	-
111IP	Accum Prov for Amort-Intangible Plant												
		D_SPLIT	S	(140,175)	-	-	(132,819)	(1,618)	-	-	(5,738)	-	-
		LABOR	SG	-	-	-	-	-	-	-	-	-	-
		LABOR	SG	(103,514)	(42,114)	(7,897)	(37,129)	(594)	-	(6,056)	(6,390)	(3,335)	-
		P	SE	21,235	21,235	-	-	-	-	-	-	-	-
		LABOR	SG	(30,133,638)	(12,259,522)	(2,298,886)	(10,808,325)	(173,057)	-	(1,762,871)	(1,860,065)	(970,913)	-
		I-SG	SG	(30,888,669)	(20,283,571)	(10,579,811)	(24,482)	-	-	-	(805)	-	-
		I-SG	SG	(1,554,304)	(1,020,660)	(532,371)	(1,232)	-	-	-	(40)	-	-
		CSS_SYS	CN	(56,627,623)	-	-	-	-	-	(25,104,913)	(13,213,112)	(18,309,598)	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	(92,153,375)	(37,491,533)	(7,030,351)	(33,053,547)	(529,236)	-	(5,391,137)	(5,688,368)	(2,969,202)	-
				(211,580,064)	(71,076,165)	(20,449,317)	(44,057,534)	(704,506)	-	(32,264,977)	(20,774,517)	(22,253,048)	-
111IP	Less Non-Utility Plant												
		NUTIL	OTH	-	-	-	-	-	-	-	-	-	-
				(211,580,064)	(71,076,165)	(20,449,317)	(44,057,534)	(704,506)	-	(32,264,977)	(20,774,517)	(22,253,048)	-
111390	Accum Amtr - Capital Lease												
		LABOR	S	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
	Remove Capital Lease Amtr			-	-	-	-	-	-	-	-	-	-
TOTAL ACCUM PROV FOR AMORTIZATION				**(218,109,109)**	**(72,164,303)**	**(20,477,039)**	**(49,139,039)**	**(766,899)**	**-**	**(32,286,235)**	**(21,010,836)**	**(22,264,757)**	**-**

Docket No. UE 399
Exhibit PAC/1104
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Functional Factors

March 2022

Functional Factors

Function	Description	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM	Total
					Internal Factors						
CWC	Cash Working Capital	63.6608%	9.3861%	23.6202%	0.1728%	0.0000%	1.2907%	1.0747%	0.7946%	0.0000%	100.0000%
D_SPLIT	Distribution Split between Functions	0.0000%	0.0000%	94.7526%	1.1541%	0.0000%	0.0000%	4.0933%	0.0000%	0.0000%	100.0000%
GP	Gross Plant	42.6142%	24.0096%	30.4331%	0.3752%	0.0000%	0.5596%	1.6415%	0.3668%	0.0000%	100.0000%
IBT	Income Before Taxes	272.5050%	-40.5134%	-131.9652%	-3.5471%	0.0000%	6.4893%	-7.7107%	4.7421%	0.0000%	100.0000%
NP	Net Plant	38.6979%	30.1295%	28.5632%	0.3114%	0.0000%	0.2736%	1.8593%	0.1651%	0.0000%	100.0000%
PT	Production / Transmission	62.6163%	37.3837%								100.0000%
PTD	Prod, Trans, Dist Plant	43.3975%	25.9096%	30.6929%							100.0000%
REVREQ	Revenue Requirement	58.3615%	13.6152%	24.7771%	0.1955%	0.0000%	1.0811%	1.2967%	0.6729%	0.0000%	100.0000%
T_SPLIT	Transmission Split	2.0469%	97.9531%								100.0000%
TD	Transmission / Distribution		45.7746%	54.2254%							100.0000%
					External Factors						
ACCMDIT	Deferred Income Tax - Balance	50.0593%	25.1772%	24.6386%	0.0000%	0.0000%	0.0624%	0.0626%	0.0000%	0.0000%	100.0000%
ANC	Ancillary Function	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
B_CENTER	Business Centers	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	65.1446%	0.0000%	34.8554%	0.0000%	100.0000%
BOOKDEPR	Book Depreciation	66.9276%	13.4979%	18.6061%	0.2634%	0.0000%	0.0934%	0.6115%	0.0000%	0.0000%	100.0000%
C_BILLING	Customer Billing	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	100.0000%
C_METER	Customer Metering	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	100.0000%
C_SERVICE	Customer Other	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	100.0000%
CSS_SYS	CSS System	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	44.3333%	23.3333%	32.3333%	0.0000%	100.0000%
CUST	Customer	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	44.3333%	23.3333%	32.3333%	0.0000%	100.0000%
CUST901	Supervision	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	44.8021%	48.4141%	6.7838%	0.0000%	100.0000%
CUST903	Cust. Records & Coll. Exp.	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	67.0500%	5.7551%	27.1949%	0.0000%	100.0000%
CUST905	Misc. Customer Acct. Exp.	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	100.0000%
D	Distribution Only	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
DL	Distribution Only-LGT	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
DDS2	Deferred Debits - Situs	77.3972%	3.1278%	16.0812%	0.1232%	0.0000%	1.2551%	1.3243%	0.6912%	0.0000%	100.0000%
DDS6	Deferred Debits - Situs	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
DDSO2	Deferred Debits - System Overhead	39.6393%	7.7128%	37.9806%	0.5325%	0.0000%	5.4242%	5.7232%	2.9874%	0.0000%	100.0000%
DDSO6	Deferred Debits - System Overhead	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
DEFSG	Deferred Debit - System Generation	91.6259%	8.3741%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
DSM	Demand Side Management	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
DPW	Distribution Poles & Wires	0.0000%	0.0000%	96.8179%	0.0000%	0.0000%	0.0000%	3.1821%	0.0000%	0.0000%	100.0000%
ESD	Environmental Services Department	30.0000%	10.0000%	60.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
FERC	FERC Fees	40.2029%	59.7971%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
G	General Plant	20.3997%	36.1935%	40.7338%	0.0000%	0.0000%	1.3343%	1.3388%	0.0000%	0.0000%	100.0000%
G-DGP	General Plant - DGP Factor	63.3519%	36.6481%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
G-DGU	General Plant - DGU Factor	63.3519%	36.6481%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
G-SG	General Plant - SG Factor	41.1499%	58.8501%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
G-SITUS	General Plant - SITUS Factor	0.0000%	31.1670%	66.6426%	0.0000%	0.0000%	0.0000%	2.1903%	0.0000%	0.0000%	100.0000%
I	Intangible Plant	48.5579%	17.0250%	12.1643%	0.0000%	0.0000%	7.8659%	8.3673%	6.0196%	0.0000%	100.0000%
I-DGP	Intangible Plant - DGP Factor	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
I-DGU	Intangible Plant - DGU Factor	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
I-SG	Intangible Plant - SG Factor	65.6667%	34.2514%	0.0793%	0.0000%	0.0000%	0.0000%	0.0026%	0.0000%	0.0000%	100.0000%
I-SITUS	Intangible Plant - SITUS Factor	0.0000%	2.4335%	94.4618%	0.0000%	0.0000%	0.0000%	3.1047%	0.0000%	0.0000%	100.0000%
LABOR	Direct Labor Expense	40.6838%	7.6290%	35.8680%	0.5743%	0.0000%	5.8502%	6.1727%	3.2220%	0.0000%	100.0000%
MSS	Materials & Supplies	81.6861%	1.4794%	16.2988%	0.0000%	0.0000%	0.0000%	0.5357%	0.0000%	0.0000%	100.0000%
NONE	Not Functionalized	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
NUTIL	Non-Utility	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
OTHDGP	Other Revenues - DGP Factor	22.9341%	77.0630%	0.0029%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
OTHDGU	Other Revenues - DGU Factor	22.9341%	77.0630%	0.0029%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
OTHSE	Other Revenues - SE Factor	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
OTHSG	Other Revenues - SG Factor	22.9341%	77.0630%	0.0029%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
OTHSGR	Other Revenues - Rolled-In SG Factor	22.9341%	77.0630%	0.0029%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
OTHSITUS	Other Revenues - SITUS	0.3440%	89.6679%	9.9881%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
OTHSO	Other Revenues - SO Factor	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
P	Production	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
SCHMA	Schedule M Additions	58.6408%	14.4458%	24.6911%	0.0213%	0.0000%	0.8772%	1.0855%	0.2381%	0.0000%	100.0000%
SCHMAF	Schedule M Additions - Flow Through	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
SCHMAP	Schedule M Additions - Permanent	74.5155%	3.2777%	15.4102%	0.2467%	0.0000%	2.5135%	2.6520%	1.3843%	0.0000%	100.0000%
SCHMAP-SO	Schedule M Additions - Permanent-SO	75.5976%	3.1385%	14.7559%	0.2363%	0.0000%	2.4067%	2.5394%	1.3255%	0.0000%	100.0000%
SCHMAT	Schedule M Additions - Temporary	58.5956%	14.4776%	24.7176%	0.0207%	0.0000%	0.8726%	1.0811%	0.2349%	0.0000%	100.0000%
SCHMAT-SG	Schedule M Additions - Temporary-SG	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
SCHMAT-SE	Schedule M Additions - Temporary-SE	99.8835%	0.0150%	0.0704%	0.0011%	0.0000%	0.0115%	0.0121%	0.0063%	0.0000%	100.0000%
SCHMAT-SITU	Schedule M Additions - Temporary-SITUS	100.5549%	-0.4620%	-0.1999%	0.0045%	0.0000%	0.0458%	0.0314%	0.0252%	0.0000%	100.0000%
SCHMAT-SNP	Schedule M Additions - Temporary-SNP	46.2446%	26.7584%	26.1334%	0.0000%	0.0000%	0.0022%	0.8600%	0.0015%	0.0000%	100.0000%
SCHMAT-SO	Schedule M Additions - Temporary-SO	40.5835%	7.2842%	36.0435%	0.5847%	0.0000%	5.9556%	6.2685%	3.2801%	0.0000%	100.0000%
SCHMD	Schedule M Deductions	63.5198%	20.6824%	16.3163%	-0.0659%	0.0000%	-0.0089%	-0.2770%	-0.1667%	0.0000%	100.0000%
SCHMDF	Schedule M Deductions - Flow Through	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
SCHMDP	Schedule M Deductions - Permanent	99.0933%	0.4514%	0.4408%	0.0000%	0.0000%	0.0000%	0.0145%	0.0000%	0.0000%	100.0000%
SCHMDP-SO	Schedule M Deductions - Permanent- SO	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
SCHMDT	Schedule M Deductions - Temporary	63.3764%	20.7640%	16.3802%	-0.0661%	0.0000%	-0.0089%	-0.2782%	-0.1673%	0.0000%	100.0000%
SCHMDT-GPS	Schedule M Deductions - Temporary-GPS	46.2535%	26.7567%	26.1309%	0.0000%	0.0000%	0.0000%	0.8588%	0.0000%	0.0000%	100.0000%
SCHMDT-SG	Schedule M Deductions - Temporary-SG	99.9797%	0.0203%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
SCHMDT-SITU	Schedule M Deductions - Temporary-SITUS	109.3757%	-2.4106%	-5.9473%	-0.0339%	0.0000%	-0.3611%	-0.4219%	-0.2009%	0.0000%	100.0000%
SCHMDT-SNP	Schedule M Deductions - Temporary-SNP	46.2535%	26.7567%	26.1309%	0.0000%	0.0000%	0.0000%	0.8588%	0.0000%	0.0000%	100.0000%
SCHMDT-SO	Schedule M Deductions - Temporary-SO	35.4236%	-22.5098%	43.5913%	1.6291%	0.0000%	16.5684%	16.1757%	9.1218%	0.0000%	100.0000%
STEP_UP	Step-up Transformers	7.0314%	92.9686%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
T	Transmission	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
TAXDEPR	Tax Depreciation	62.2078%	18.8524%	17.4885%	0.0200%	0.0000%	0.5807%	0.4711%	0.3794%	0.0000%	100.0000%

Docket No. UE 399
Exhibit PAC/1105
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Ancillary Services Revenue Requirement

March 2022

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
Ancillary Services Revenue
12 Months Ended December 31, 2023 Forecast

Oregon Annual Ancillary Service Revenue $23,847,685

Calculation below per the PacifiCorp Open Access Transmission Tariff (OATT) Load and Generation prices on
Schedule 3 (Regulation and Frequency Response Service), Schedule 3A (Generator Regulation and Frequency Response Service), Schedule 5 (Operating Reserve - Spinning Reserve Service) and Schedule 6 (Operating Reserve - Supplemental Reserve Service)

Load[1]

Line	Description	Calculation	Value
1	Sum of 12 Oregon Monthly Peaks (MW)		27,220
2	Total Oregon Retail Load (MWh)		15,310,450
3			
4	Schedule 3 Load Rate ($/MW-month)		$115
5	Schedule 3 Revenue	1*4	$3,130,277
6			
7	Schedule 5 Rate ($/MWh)		$0.168
8	Schedule 5 Revenue	2*7	$2,572,156
9			
10	Schedule 6 Rate ($/MWh)		$0.168
11	Schedule 6 Revenue	2*10	$2,572,156
12			
13			
14	Total Oregon Load Revenue	5+8+11	$8,274,588

Generation

Line	Description	Calculation	Value
1	Sum of 12 Total System VER Generator Nameplate Capacities (MW)[2]		67,991
2	Sum of 12 Total System Non-VER Generator Nameplate Capacities (MW)		12,114
3	Total System Generation MWh at input		62,280,620
4			
5	Schedule 3A VER Rate ($/MW-month)		$524
6	Schedule 3A VER Revenue	1*5	$35,634,858
7			
8	Schedule 3A Non-VER Rate ($/MW-month)		$262
9	Schedule 3A Non-VER Revenue	2*8	$3,173,767
10			
11	Schedule 5 Rate ($/MWh)		$0.168
12	Schedule 5 Revenue	3*11	$10,463,144
13			
14	Schedule 6 Rate ($/MWh)		$0.168
15	Schedule 6 Revenue	3*14	$10,463,144
16			
17			
18	Total Generation Revenue	6+9+12+15	$59,734,914
19			
20	Oregon JAM SG Factor		26%
21	Oregon-allocated Total Generation Revenue	18*20	$15,573,096

[1] Load is Oregon's Contributions to Monthly Firm System Retail Load at input
[2] All VER Generation is assumed to be Uncommitted (see OATT Schedule 3A requirements for Committed and Uncommitted)

Docket No. UE 399
Exhibit PAC/1106
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Oregon Marginal Cost of Service Study Summary

March 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)

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)
			Residential	General Service - Schedule 23			General Service - Schedule 28				General Service - Schedule 30			Large Power Service - Schedule 48					Irrg - Sch 41	Lighting
				0-15 kW	15+ kW	Primary	0-50 kW	51-100 kW	100 + kW	Primary	0-300 kW	300+ kW	Primary	1 - 4 MW	1 - 4 MW	> 4 MW	> 4 MW	Trn		Schs 15, 51,
Line	Class / Function	Total	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)	53, 54 (sec)
1	Demand Related Marginal Cost																			
2	Generation	$220,002	$107,503	$8,554	$9,332	$44	$6,793	$10,074	$12,856	$344	$2,783	$13,848	$1,425	$6,976	$6,491	$474	$11,655	$17,333	$3,516	$0
3	Transmission	$10,329	$5,047	$402	$438	$2	$319	$473	$604	$16	$131	$650	$67	$328	$305	$22	$547	$814	$165	$0
4	Distribution																			
5	Poles	$43,954	$23,495	$2,370	$2,643	$9	$1,252	$1,841	$2,351	$56	$377	$1,857	$180	$2,043	$1,894	$4	$123	$0	$3,383	$77
6	Conductor	$64,852	$36,118	$3,168	$3,533	$12	$1,905	$2,800	$3,577	$85	$653	$3,215	$312	$2,658	$2,464	$9	$238	$0	$4,004	$103
7	Substations	$44,587	$25,258	$1,670	$1,863	$6	$1,331	$1,957	$2,500	$59	$554	$2,726	$264	$1,406	$1,304	$96	$2,363	$0	$1,230	$0
8	Transformers	$9,372	$5,495	$675	$419	$0	$434	$716	$562	$0	$102	$385	$0	$192	$0	$13	$0	$0	$341	$37
9	Total Demand	$393,096	$202,915	$16,837	$18,228	$74	$12,034	$17,862	$22,449	$559	$4,600	$22,681	$2,248	$13,602	$12,458	$619	$14,926	$18,147	$12,640	$218
10																				
11																				
12	Energy Related Marginal Cost																			
13	Generation	$526,179	$214,837	$20,792	$22,439	$125	$16,672	$25,372	$33,020	$894	$7,293	$37,824	$3,696	$19,341	$18,778	$1,476	$36,197	$56,490	$10,051	$883
14	Transmission	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
15	Total Energy	$526,179	$214,837	$20,792	$22,439	$125	$16,672	$25,372	$33,020	$894	$7,293	$37,824	$3,696	$19,341	$18,778	$1,476	$36,197	$56,490	$10,051	$883
16																				
17	Customer Related Marginal Cost																			
18	Poles	$55,496	$42,111	$8,672	$1,790	$14	$382	$282	$160	$5	$12	$29	$3	$12	$8	$0	$0	$0	$2,015	$0
19	Conductor	$27,553	$20,908	$4,305	$889	$7	$190	$140	$79	$3	$6	$14	$1	$6	$4	$0	$0	$0	$1,001	$0
20	Transformers	$76,429	$45,720	$12,013	$3,293	$0	$3,414	$2,868	$1,754	$0	$211	$527	$0	$91	$0	$1	$0	$0	$6,535	$0
21	Lighting	$6,326	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,326
22	Service Drops	$53,903	$40,536	$7,153	$2,859	$0	$989	$763	$836	$0	$88	$424	$0	$252	$0	$3	$0	$0	$0	$0
23	Meters	$16,150	$12,418	$1,724	$409	$134	$154	$122	$357	$80	$38	$95	$62	$20	$71	$0	$33	$159	$273	$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	$174	$36	$0	$121	$89	$50	$2	$32	$79	$8	$64	$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)	$264,503	$185,235	$36,801	$9,846	$160	$5,468	$4,426	$3,326	$93	$397	$1,195	$77	$475	$145	$5	$61	$167	$10,034	$6,590
29																				
30																				
31	Total Revenue @ Full MC																			
32	Generation	$746,181	$322,340	$29,346	$31,771	$169	$23,465	$35,447	$45,875	$1,238	$10,076	$51,673	$5,121	$26,317	$25,269	$1,951	$47,852	$73,823	$13,567	$883
33	Transmission	$10,329	$5,047	$402	$438	$2	$319	$473	$604	$16	$131	$650	$67	$328	$305	$22	$547	$814	$165	$0
34	Distribution	$376,144	$239,641	$40,026	$17,289	$49	$9,897	$11,368	$11,817	$207	$2,002	$9,178	$760	$6,659	$5,673	$126	$2,724	$0	$18,509	$218
35	Distribution-Lighting	$6,326	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,326
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	$16,150	$12,418	$1,724	$409	$134	$154	$122	$357	$80	$38	$95	$62	$20	$71	$0	$33	$159	$273	$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)	$1,177,864	$597,832	$74,257	$50,476	$358	$34,053	$47,571	$58,745	$1,545	$12,258	$61,622	$6,012	$33,354	$31,338	$2,100	$51,165	$74,798	$32,688	$7,691
40																				
41	Customer - Uncollectables	$5,914	$5,155	$174	$36	$0	$121	$89	$50	$2	$32	$79	$8	$64	$43	$1	$20	$6	$36	$0
42	Total Revenue	$1,183,778	$602,987	$74,431	$50,512	$359	$34,174	$47,660	$58,795	$1,546	$12,289	$61,701	$6,020	$33,418	$31,381	$2,100	$51,185	$74,804	$32,724	$7,691

Docket No. UE 399
Exhibit PAC/1107
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Unbundled Revenue Requirement Allocation

March 2022

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
December 31, 2023 Unbundled Revenue Requirement Allocation by Load Class

			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)			
			Residential	General Service		General Service		General Service		Large Power Service			Irrigation	Lighting	Lighting Detail		
		Total		Sch 23		Sch 28		Sch 30		Sch 48			Sch 41	Schs 15, 51,	Schs 15 & 51	Sch 53	Sch 54
Line	Description		(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)	53, and 54	(sec)	(sec)	(sec)
1	Total Operating Revenues	$1,238,175	$597,063	$124,106	$332	$161,664	$2,068	$86,965	$7,232	$40,979	$96,027	$87,395	$29,194	$5,151	$4,413	$657	$82
2	MWh	13,886,900	5,633,856	1,133,687	3,324	1,968,466	23,804	1,183,142	98,439	545,911	1,464,317	1,545,236	263,565	23,152	10,559	11,452	1,141
3																	
4	Functionalized 20 Year Full Marginal Costs - Class $																
5	Generation	$746,181	$322,340	$61,117	$169	$104,787	$1,238	$61,749	$5,121	$28,268	$73,121	$73,823	$13,567	$883	$403	$437	$44
6	Transmission	$10,329	$5,047	$840	$2	$1,396	$16	$781	$67	$350	$852	$814	$165	$0	$0	$0	$0
7	Distribution	$376,144	$239,641	$57,315	$49	$33,082	$207	$11,180	$760	$6,785	$8,397	$0	$18,509	$218	$203	$5	$9
8	Distribution-Lighting	$6,326	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,326	$6,326	$0	$0
9	Customer - Billing	$16,770	$13,430	$2,556	$3	$366	$2	$26	$2	$27	$26	$2	$132	$196	$185	$8	$3
10	Customer - Metering	$16,150	$12,418	$2,132	$134	$632	$80	$133	$62	$20	$104	$159	$273	$3	$0	$0	$3
11	Customer - Other	$5,964	$4,955	$774	$1	$106	$1	$11	$1	$4	$4	$0	$41	$66	$62	$3	$1
12	Total	$1,177,864	$597,832	$124,734	$358	$140,369	$1,545	$73,880	$6,012	$35,454	$82,503	$74,798	$32,688	$7,691	$7,178	$453	$59
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%	3.79%	9.80%	9.89%	1.82%	0.12%	0.05%	0.06%	0.01%
17	Transmission	100.00%	48.86%	8.13%	0.02%	13.51%	0.16%	7.56%	0.65%	3.39%	8.25%	7.88%	1.60%	0.00%	0.00%	0.00%	0.00%
18	Distribution	100.00%	63.71%	15.24%	0.01%	8.80%	0.06%	2.97%	0.20%	1.80%	2.23%	0.00%	4.92%	0.06%	0.05%	0.00%	0.00%
19	Distribution-Lighting	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	100.00%	0.00%	0.00%
20	Ancillary Service	100.00%	43.20%	8.19%	0.02%	14.04%	0.17%	8.28%	0.69%	3.79%	9.80%	9.89%	1.82%	0.12%	0.05%	0.06%	0.01%
21	Customer - Billing	100.00%	80.09%	15.24%	0.02%	2.18%	0.01%	0.16%	0.01%	0.16%	0.15%	0.01%	0.79%	1.17%	1.10%	0.05%	0.02%
22	Customer - Metering	100.00%	76.89%	13.20%	0.83%	3.92%	0.50%	0.82%	0.38%	0.12%	0.64%	0.99%	1.69%	0.02%	0.00%	0.00%	0.02%
23	Customer - Other	100.00%	83.09%	12.98%	0.02%	1.78%	0.01%	0.18%	0.01%	0.07%	0.07%	0.01%	0.69%	1.10%	1.04%	0.05%	0.02%
24	Embedded DSM - (MWh)	100.00%	40.57%	8.16%	0.02%	14.17%	0.17%	8.52%	0.71%	3.93%	10.54%	11.13%	1.90%	0.17%	0.08%	0.08%	0.01%
25	Regulatory & Franchise - (Total Operating Revenues)	100.00%	48.22%	10.02%	0.03%	13.06%	0.17%	7.02%	0.58%	3.31%	7.76%	7.06%	2.36%	0.42%	0.36%	0.05%	0.01%
26																	
27																	
28	Functionalized Class Revenue Requirement - (Target)																
29	Generation	$744,404	$321,572	$60,971	$168	$104,538	$1,235	$61,602	$5,108	$28,200	$72,947	$73,647	$13,535	$881	$402	$436	$43
30	Transmission	$179,693	$87,806	$14,609	$36	$24,277	$281	$13,585	$1,164	$6,085	$14,821	$14,157	$2,872	$0	$0	$0	$0
31	Distribution	364,324	$232,110	$55,514	$48	$32,043	$201	$10,829	$736	$6,572	$8,133	$0	$17,928	$211	$196	$5	$9
32	Distribution-Lighting	$3,032	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,032	$3,032	$0	$0
33	Distribution Total	367,356	$232,110	$55,514	$48	$32,043	$201	$10,829	$736	$6,572	$8,133	$0	$17,928	$3,243	$3,229	$5	$9
34	Ancillary Services	$23,675	$10,227	$1,939	$5	$3,325	$39	$1,959	$162	$897	$2,320	$2,342	$430	$28	$13	$14	$1
35	Customer - Billing	$15,079	$12,076	$2,298	$3	$329	$2	$24	$2	$24	$23	$2	$119	$177	$167	$8	$2
36	Customer - Metering	$21,031	$16,171	$2,777	$174	$824	$105	$173	$80	$26	$135	$207	$356	$3	$0	$0	$3
37	Customer - Other	$9,224	$7,664	$1,197	$2	$164	$1	$17	$1	$6	$6	$1	$63	$102	$96	$4	$1
38	Embedded DSM - (MWh)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
39	Franchise Fees	$32,642	$15,740	$3,272	$9	$4,262	$55	$2,293	$191	$1,080	$2,532	$2,304	$770	$136	$116	$17	$2
40	Total	$1,393,104	$703,367	$142,577	$445	$169,761	$1,918	$90,480	$7,445	$42,891	$100,917	$92,661	$36,073	$4,569	$4,022	$484	$63
41																	
42	Ratio of Operating Revn to Revenue Requirement-(Target)	88.88%	84.89%	87.05%	74.61%	95.23%	107.83%	96.12%	97.13%	95.54%	95.15%	94.32%	80.93%	112.73%	109.71%	135.70%	129.01%
43	(Line 1 / Line 40)																
44																	
45	Increase or (Decrease)	$154,929	$106,304	$18,470	$113	$8,097	($150)	$3,515	$213	$1,913	$4,890	$5,266	$6,879	($582)	($391)	($173)	($18)
46	(Line 40 - Line 1)																
47																	
48																	
49	Percent Increase (Decrease)	12.51%	17.80%	14.88%	34.03%	5.01%	-7.26%	4.04%	2.95%	4.67%	5.09%	6.03%	23.56%	-11.29%	-8.85%	-26.31%	-22.49%
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	$698,716	$133,281	$319,434	$2,548	$23,848	$14,720	$18,059	$9,077	$29,219	$1,248,901
2											
3	Percent of Total	55.95%	10.67%	25.58%	0.20%	1.91%	1.18%	1.45%	0.73%	2.34%	100.00%
4											
5	Revenue From Classes Included in MC Study	$692,715	$132,136	$316,690	$2,526	$23,643	$14,594	$17,904	$8,999	$28,968	$1,238,175
6											
7	Other Revenues										
8	Schedule 4 - Employee Discount										($341)
9	Partial Requirements - Sch. 47 pri										$1,607
10	Partial Requirements - Sch. 47 trn										$2,367
11	Sch 848										$1,805
12	Oregon Direct Access Opt Out Amortization										$1,767
13	AGA										$3,521
14	Total Oregon Situs Revenue										$1,248,901

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
Oregon Marginal Cost Study
December 31, 2023 Functionalized Revenue - Target
($ 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	Target Functional Revenue Requirement	$749,838	$181,005	$366,984	$3,055	$23,848	$15,189	$21,184	$9,292	$32,880	$1,403,274	
2												
3	Percent of Total	53.43%	12.90%	26.15%	0.22%	1.70%	1.08%	1.51%	0.66%	2.34%	100.00%	
4												Increase
5	Revenue From Classes Included in MC Study	$744,404	$179,693	$364,324	$3,032	$23,675	$15,079	$21,031	$9,224	$32,642	$1,393,104	$154,929
6												
7	Other Revenues											$154,373
8	Schedule 4 - Employee Discount										($399)	($59)
9	Partial Requirements - Sch. 47 pri										$1,623	$16
10	Partial Requirements - Sch. 47 trn										$2,286	($81)
11	Sch 848										$1,374	($432)
12	Oregon Direct Access Opt Out Amortization										$1,767	$0
13	AGA										$3,521	($0)
14	Total Oregon Situs Revenue										$1,403,274	

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	Lighting
Line	Description		(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	Irrigation	(sec)
1	Total Transmission Revenue Requirement	$179,693	$87,806	$14,609	$36	$24,277	$281	$13,585	$1,164	$6,085	$14,821	$14,157	$2,872	$0
2														
3	FERC Transmission													
4	Peak MW @ Input	2,358	1,152	192	0	319	4	178	15	80	195	186	38	0
5	% of Total	100.00%	48.86%	8.13%	0.02%	13.51%	0.16%	7.56%	0.65%	3.39%	8.25%	7.88%	1.60%	0.00%
6	FERC Transmission Revenues ($ 000)	$84,946	$41,508	$6,906	$17	$11,477	$133	$6,422	$550	$2,877	$7,006	$6,693	$1,358	$0
7														
8	Other Transmission Revenue Requirement	$94,747	$46,297	$7,703	$19	$12,801	$148	$7,163	$614	$3,209	$7,815	$7,465	$1,514	$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

Docket No. UE 399
Exhibit PAC/1108
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Oregon Marginal Cost of Service Study

March 2022

PacifiCorp
Marginal Cost Study & Circuit Model Procedures

INTRODUCTION

Customer class marginal costs are developed to illustrate the resources required to produce one additional unit of electricity or add one additional customer to the system. One, five, ten and twenty years marginal costs are calculated because the Company believes the Commission should have information about the Company's marginal costs over different time periods. Twenty-year (or long run) marginal costs, however, are the primary time frame used in setting retail tariff prices.

The one-year marginal costs include only changes in operating costs, while ten- and twenty-year marginal costs also include the cost of expanding facilities. The cost of added facilities results in long-run costs, which are higher than short-run costs. Short-run costs include only one year of generation energy costs and some billing costs. There are no short-run demand-related generation, transmission or distribution costs. Long-run costs include ten or twenty years of generation costs, transmission and distribution costs.

One, ten and twenty-year marginal costs are summarized by customer class and load size group and shown in mills/kilowatt-hour (kWh). Marginal commitment costs and billing expenses, which are sometimes referred to as customer costs, are shown in dollars per customer per year. Costs are shown for both the one-year and the long-run time periods.

Unit costs are adjusted to 2023 values and are shown by generation, transmission, and distribution functional categories and by demand, energy, and commitment and billing costing classifications. Also included are energy usage, peak demand, and number of customers by customer class for the 12 month period ending December 2023.

One, ten and twenty-year marginal costs in mills/kilowatt-hour (kWh) are shown on "Summary of Marginal Costs Demand & Energy in Mills/kWh" (Sheet 'Table 1'). Marginal commitment costs and billing expenses are shown on "Summary of Marginal Costs Commitment and Billing in $ / Customer / Month" (Sheet 'Table 2'). Billing information, unit costs, and total marginal costs are shown on "20 Year Marginal Cost" (Sheet 'Table 3').

MARGINAL GENERATION COSTS

The development of marginal generation costs for this study is consistent with the analysis done to prepare the Company's avoided costs filings. Marginal generation costs are based on the Company's most recent avoided cost calculations. The analysis recognizes that baseload generation produces the dual products of capacity and energy. The new resource costs are based on the fixed and variable cost of a Combined Cycle Combustion Turbine (CCCT), which operates as a baseload unit. The cost of the CCCT is split into capacity and energy components. The fixed cost of a simple cycle combustion turbine (SCCT) defines the fixed costs of the CCCT that are assigned to capacity. CCCT fixed costs which are in excess of SCCT fixed costs are assigned to energy. Total energy and capacity costs are present valued, summed, and an annual charge is applied to the total. The marginal generation cost calculation is shown in the cost of service study on sheet "Summary of Marginal Generation Costs in Nominal Dollars" (Sheet 'Table 4').

MARGINAL TRANSMISSION COSTS

The calculation of transmission costs are based on a five-year (2020-2024) analysis of forecasted expenditures to meet increased load on the transmission system. All of these growth-related transmission investments, except bulk power lines, are classified entirely to demand.

Unlike growth-related system support and local transmission investments, the Company's investment in bulk power lines is classified both to demand and energy in the same proportions as twenty-year marginal costs of generation resources. Bulk transmission costs are classified this way because they are thought to be an integral part of the generation system. The Company's investments in high voltage bulk transmission lines are being made to move both energy and capacity. It is usually not possible to site a thermal plant close to the customers the plant is intended to serve. Instead, bulk power lines are constructed to transmit the energy being generated, along with the accompanying capacity.

Each year's growth-related transmission investments are adjusted to 2023 dollars and the five years are totaled. The total transmission investment is divided by the capacity added by the investment to determine the marginal investment per kilowatt (kW). An annual charge for including an A&G expense loading factor and a transmission O&M loading factor are added to the per kW investment to arrive at long-run transmission marginal cost.

The marginal transmission calculation including the split between demand and energy can be seen in the marginal cost study on page "Marginal Transmission Investment and O&M Expenses" (Sheet 'Transm1'). A summarized version of this page is "Marginal Cost of Transmission Investment and Associated Expenses" (Sheet 'Table 5').

MARGINAL DISTRIBUTION COSTS

Distribution costs are classified into three components: Demand-related, shown in dollars per kW/year, commitment-related, shown in dollars per customer/year, and billing-related, shown in dollars per customer/year. Commitment costs consist of the costs of transformers, poles, and conductor that are not determined by the level of demand customers place on the system. Demand-related costs are the additional costs of larger transformers, substations, poles, and conductors with sufficient capacity to serve the level of demand a customer class places on the system. Billing costs are the costs of meters, service drops, and customer accounting functions.

A summary of distribution marginal costs showing these three components is on page "Marginal Distribution & Billing Costs" (Sheet 'Table 6').

Marginal line transformer costs are calculated using a least squares regression analysis of the current installed cost versus size of the Company's commonly installed transformers. Commitment and demand costs are separated by the nature of the statistical technique.

The regression provides an intercept term, which represents the commitment costs, and a slope, which represents the demand cost per kW. The regression also identifies the additional costs of a three-phase transformer over a single-phase transformer.

Line transformer regression results are shown on page “Calculation of Escalation Factors for Transformers” (Sheet ‘XFMR3’). Transformer demand costs are shown on page “Transformer Demand Costs” (Sheet ‘XFMR2’) and commitment costs are shown on page “Transformer Commitment Costs” (Sheet ‘XFMR1’).

Marginal costs of distribution poles and wires are calculated using the Company’s Distribution Circuit Model (Sheets ‘PC3’ through ‘PC14’). The circuit model focuses on several key characteristics that influence distribution cost of service. Among these are customer density, customer size and usage characteristics, and customer location on the circuit. The hypothetical circuit is constructed with seven branches of equal length using the composite line statistics for the state of Oregon. The model determines the cost of the circuit by using current cost estimates to construct one mile of distribution facilities using each of the Company’s single and three phase wire sizes. The results are segregated into commitment related and demand related costs for each customer class. A more detailed description of the circuit model is included as an appendix to this narrative.

Marginal poles and wire costs are shown on page "Hypothetical Circuit Study Results Annual Demand and Commitment Costs” (Sheet ‘PC1’).

Marginal substation costs are determined using the per kW cost of budgeted and forecasted substation additions for the five year period 2020 - 2024. As part of the capital budgeting process the company determines which substations are approaching their maximum design loading. When load can no longer be shifted to adjacent substations, an upgrade, either greater capacity at the substation or a new substation, is required. The capital investment in common year dollars is totaled across all projects and across the budget-planning horizon to produce total substation investment.

This substation investment is then multiplied by a substation utilization factor. The substation utilization factor is calculated by dividing the maximum distribution peak by the installed capacity of existing distribution substations. The distribution peak is expanded by transmission voltage level losses and substation thermal loading. Applying a utilization factor to distribution substation costs reflects the fact that substation capacity additions are typically done in blocks which result in some substations being close to being fully utilized and others operating well below peak capacity. This weighted substation investment is, finally, divided by the associated incremental substation capacity to get dollars / kW. The dollars per kW is adjusted to an annual value by applying a real levelized carrying charge. Substation marginal costs are classified entirely to demand, and are allocated to customer classes based on the distribution peak load for each class.

Page "Substation Investment” (Sheet ‘DistSub2’) shows the detail of the substation calculation. "Distribution Substation Costs / kW 2021 Dollars” (Sheet ‘DistSub1’) shows the annualized cost in $/kW.

The marginal cost of services includes the costs of new service drop investment plus associated O&M expense. Average service drop investments are determined for each customer load size by analyzing service requirements, such as single or three-phase service and voltage level. Incremental service drop O&M is based on the average of ten years of historical expenditures.

The metering category includes the marginal cost of metering equipment with associated O&M expense. Average meter investments are determined for each customer load size by analyzing service requirements, such as single or three-phase service and voltage level. Meter O&M expense is based on historical expenditures.

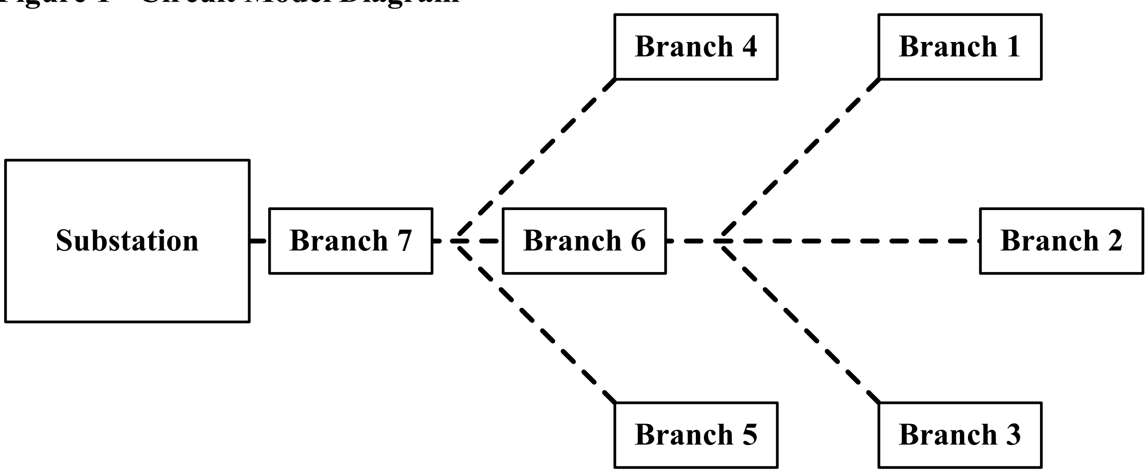
The billing customer service/other category includes the costs of billing, payment processing, debt recovery, meter reading expenses and all remaining customer accounting and customer service activities. Customer accounting and customer service expense are based on the most recent five years of expenditures and are assigned to each customer class based on the various resources required to perform billing, collections, and customer service activities for different types of customers.

Weighted average installed service drop cost calculations are located on Sheets 'Services 1' through 'Services 3' and the weighted average installed meter cost calculations are included on Sheets 'Meters 1' through 'Meters 5'. The customer accounting and informational expense calculation is on page "Summary of Customer Accounting Expense by Schedule" (Sheet 'Cust Exp Sum'). These calculations are brought together on "Marginal Distribution & Billing Costs" (Sheet 'Table 6') to calculate metering reading, billing, collections and customer service related costs ($/Customer/Yr).

PacifiCorp
Distribution Circuit Model
PacifiCorp Distribution Circuit Model

General Overview
The PacifiCorp Distribution Circuit Model is included in Exhibit PAC/1407, Sheets PC 3 through PC 14 and calculates the cost of building a hypothetical circuit (Figure 1, below) with seven branches of equal length using the composite line statistics for a chosen state or service area. A hypothetical circuit is used rather than a sampling of actual existing circuits. This is because the diverse characteristics of PacifiCorp's six state service area, consisting of over 2,000 distribution circuits, makes the selection of any single, or small number of typical circuits impractical. The fundamental concept of the hypothetical circuit is to create a model that reduces the elements of distribution cost assignment to a workable form.

Figure 1 - Circuit Model Diagram



The circuit model focuses on several key characteristics that influence distribution cost of service. Among these are customer density, customer size and usage characteristics, and perhaps most importantly, customer location on the circuit. Each customer is assigned cost responsibility for all distribution facilities between the customer's location and the substation (upstream facilities), but no facilities beyond the customer's service location (downstream facilities). The model performs three basic functions. First, it estimates the total cost to build the composite circuit using current construction costs and state specific characteristics. Second, it divides the cost of each branch of the circuit between demand and commitment related costs. Third, it assigns the various types of costs to customer classes.

Required Engineering & Statistical Data
Listed below are the basic statistics that we use to calculate the composite circuit for a given state:

1. Current One Mile Line Construction Cost Estimates for Each Conductor Size
2. Economic Conductor Loading for Each Conductor Size

3. Overhead and Underground Line Miles
4. Number of Poles
5. Number of Circuits -- distribution line points of origin radiating from a substation.
6. Actual Customer Distances from Distribution Substations
7. Number of Customers and Loads by Class
8. Percentages of Three-Phase and Single-Phase Customers by Class

One Mile Line Estimate
The model determines the cost of the circuit by using cost estimates to construct one mile of distribution facilities using each of the Company's single and three-phase wire sizes. These cost estimates are based on typical topography and equipment configuration for an average mile of line construction. Since the number of poles per mile varies between states, we use a factor to adjust the line cost estimate from the system wide average of 26.20 poles per mile to the state average poles per mile. For example, Oregon has an average of 26.13 poles per mile. Figure 2 shows the circuit cost per mile calculation for Oregon.

Figure 2 – Adjusted Oregon Line Costs per Mile

	State Specific Account 364 Pole Statistics				Adjustment
	Poles	Pole Feet	Pole Miles	Poles / Mile	Factor
California	55,482	12,544,659	2,376	23.35	0.884
Idaho	97,406	21,318,575	4,038	24.12	0.913
Oregon	377,374	74,711,073	14,150	26.67	1.009
Utah	332,602	61,493,319	11,646	28.56	1.081
Washington	99,980	16,626,029	3,149	31.75	1.202
Wyoming	157,847	37,272,116	7,059	22.36	0.846
Total	1,120,691	223,965,771	42,418	26.42	1.000
	Account 364 Pole Cost per Mile			Account 365	Total Line
	Pole Cost	Adjustment	Adjusted	Conductor	Construction
Wire Size	per Mile	Factor	Pole Cost	Cost per Mile	Cost
1 Phase - 1/0 ACSR	$25,517	1.009	$25,758	$12,789	$38,547
3 Phase - 1/0 ACSR	$48,426	1.009	$48,883	$28,548	$77,431
3 Phase - 447 AAC & 4\0 AAC	$54,011	1.009	$54,521	$62,952	$117,473
3 Phase -795 AAC & 477 AAC	$56,143	1.009	$56,673	$110,173	$166,846

Customer Placement
One of the most significant cost drivers of marginal distribution costs is the distance between the customer and the substation. Costs increase as the distance from the substation increases.

The circuit model takes distance into account by assigning customers to the different branches of the circuit based upon actual customer locations. The actual customer distances are derived from PacifiCorp's outage management system (CADOPS). The system is able to accurately trace the flow of electricity from substation to customer as well as ascertain the exact distance it must travel.
Figure 3 shows the Customer Distribution on the Hypothetical Circuit Branch for Oregon.

Figure 3 Customer Distribution

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
	Hypothetical Circuit Branch							Branch
Class	1	2	3	4	5	6	7	Total
Res - Schedule 4 (sec)	0.38%	0.38%	0.38%	1.83%	1.83%	1.83%	93.37%	100.00%
GS - Schedule 23 - 0-15 kW (sec)	0.73%	0.73%	0.73%	2.67%	2.67%	2.67%	89.80%	100.00%
GS - Schedule 23 - 15+ kW (sec)	0.73%	0.73%	0.73%	2.67%	2.67%	2.67%	89.80%	100.00%
GS - Schedule 23 - Primary (pri)	0.73%	0.73%	0.73%	2.67%	2.67%	2.67%	89.80%	100.00%
GS - Schedule 28 - 0-50 kW (sec)	0.45%	0.45%	0.45%	1.53%	1.53%	1.53%	94.08%	100.00%
GS - Schedule 28 - 51-100 kW (sec)	0.45%	0.45%	0.45%	1.53%	1.53%	1.53%	94.08%	100.00%
GS - Schedule 28 - 100 + kW (sec)	0.45%	0.45%	0.45%	1.53%	1.53%	1.53%	94.08%	100.00%
GS - Schedule 28 - Primary (pri)	0.45%	0.45%	0.45%	1.53%	1.53%	1.53%	94.08%	100.00%
GS - Schedule 30 - 0-300 kW (sec)	0.28%	0.28%	0.28%	0.98%	0.98%	0.98%	96.23%	100.00%
GS - Schedule 30 - 300+ kW (sec)	0.28%	0.28%	0.28%	0.98%	0.98%	0.98%	96.23%	100.00%
GS - Schedule 30 - Primary (pri)	0.28%	0.28%	0.28%	0.98%	0.98%	0.98%	96.23%	100.00%
Irrigation - Sch 41	1.10%	1.10%	1.10%	7.97%	7.97%	7.97%	72.78%	100.00%
LPS - Schedule 48 - 1 - 4 MW (sec)	1.03%	1.03%	1.03%	1.37%	1.37%	1.37%	92.82%	100.00%
LPS - Schedule 48 - 1 - 4 MW (pri)	1.03%	1.03%	1.03%	1.37%	1.37%	1.37%	92.82%	100.00%
LPS - Schedule 48 - > 4 MW (sec)	Large Customers are on dedicated circuits and are not included here							
LPS - Schedule 48 - > 4 MW (pri)	Large Customers are on dedicated circuits and are not included here							

Customer Density

The next significant driver of distribution costs is customer density. The model uses state specific line and customer statistics to calculate the average number of customers by circuit branch. Total state distribution line miles and state customers, by class, are divided by the number of distribution circuits in the state to determine the average length of the composite circuit (line miles / number of circuits) and the number of customers on the circuit (customers / circuits). Figure 4 shows the average number of customers located on each of the seven circuit branches for Oregon.

Figure 4 – Oregon Average Customers by Hypothetical Circuit Branch

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
	Hypothetical Circuit Branch							
Class	1	2	3	4	5	6	7	Total
Res - Schedule 4 (sec)	3.68	3.68	3.68	17.98	17.98	17.98	915.63	980.61
GS - Schedule 23 - 0-15 kW (sec)	0.97	0.97	0.97	3.54	3.54	3.54	118.99	132.50
GS - Schedule 23 - 15+ kW (sec)	0.20	0.20	0.20	0.73	0.73	0.73	24.56	27.35
GS - Schedule 23 - Primary (pri)	0.00	0.00	0.00	0.01	0.01	0.01	0.20	0.22
GS - Schedule 28 - 0-50 kW (sec)	0.04	0.04	0.04	0.14	0.14	0.14	8.41	8.94
GS - Schedule 28 - 51-100 kW (sec)	0.03	0.03	0.03	0.10	0.10	0.10	6.21	6.60
GS - Schedule 28 - 100 + kW (sec)	0.02	0.02	0.02	0.06	0.06	0.06	3.51	3.73
GS - Schedule 28 - Primary (pri)	0.00	0.00	0.00	0.00	0.00	0.00	0.12	0.13
GS - Schedule 30 - 0-300 kW (sec)	0.00	0.00	0.00	0.00	0.00	0.00	0.39	0.41
GS - Schedule 30 - 300+ kW (sec)	0.00	0.00	0.00	0.01	0.01	0.01	0.98	1.02
GS - Schedule 30 - Primary (pri)	0.00	0.00	0.00	0.00	0.00	0.00	0.10	0.10
Irrigation - Sch 41	0.14	0.14	0.14	0.99	0.99	0.99	9.02	12.40
LPS - Schedule 48 - 1 - 4 MW (sec)	0.00	0.00	0.00	0.00	0.00	0.00	0.16	0.17
LPS - Schedule 48 - 1 - 4 MW (pri)	0.00	0.00	0.00	0.00	0.00	0.00	0.11	0.12
LPS - Schedule 48 - > 4 MW (sec)	-	-	-	-	-	-	-	-
LPS - Schedule 48 - > 4 MW (pri)	-	-	-	-	-	-	-	-
Total	5.08	5.08	5.08	23.55	23.55	23.55	1,088.39	1,174.30

Load Accumulation

The kW load that a customer or class places on the system influences the size of the conductor necessary to serve the load. At each point on the circuit, the conductor must be sized to carry the entire downstream load. At the far ends of the outer branches, loads are minimal. As you move upstream closer to the substation, the load on the circuit becomes greater requiring larger conductor sizes. In the model, load can accumulate two ways. The first occurs as customers accumulate on a branch of the circuit. When enough customers, or load, accumulate it is necessary to increment up to the next wire size. Upstream from that point, customer segments increase in cost due to the increase in wire size. The second method of load accumulation is when several branches converge at a central point on the trunk of the circuit. The trunk branches must be of adequate size to carry the load of the customers on that branch plus all downstream branches.

Figure 5 shows the circuit kW loading on each of the circuit branches for Oregon. Loads are for customers located on that branch. Accumulated loads for branch 6 would be the combined loads of branches 1, 2, 3 and 6. Accumulated loads for branch 7 would be the combined loads of all branches.

Figure 5 – Oregon Circuit kW Load by Branch

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
	Hypothetical Circuit Branch							
Class	1	2	3	4	5	6	7	Total
Res - Schedule 4 (sec)	8.97	8.97	8.97	43.77	43.77	43.77	2,229.56	2,387.77
GS - Schedule 23 - 0-15 kW (sec)	1.15	1.15	1.15	4.21	4.21	4.21	141.78	157.89
GS - Schedule 23 - 15+ kW (sec)	1.29	1.29	1.29	4.70	4.70	4.70	158.14	176.10
GS - Schedule 23 - Primary (pri)	0.00	0.00	0.00	0.02	0.02	0.02	0.56	0.62
GS - Schedule 28 - 0-50 kW (sec)	0.56	0.56	0.56	1.92	1.92	1.92	118.39	125.85
GS - Schedule 28 - 51-100 kW (sec)	0.83	0.83	0.83	2.82	2.82	2.82	174.08	185.04
GS - Schedule 28 - 100 + kW (sec)	1.06	1.06	1.06	3.61	3.61	3.61	222.32	236.32
GS - Schedule 28 - Primary (pri)	0.03	0.03	0.03	0.09	0.09	0.09	5.32	5.66
GS - Schedule 30 - 0-300 kW (sec)	0.15	0.15	0.15	0.51	0.51	0.51	50.36	52.34
GS - Schedule 30 - 300+ kW (sec)	0.72	0.72	0.72	2.52	2.52	2.52	248.00	257.71
GS - Schedule 30 - Primary (pri)	0.07	0.07	0.07	0.25	0.25	0.25	24.37	25.32
Irrigation - Sch 41	1.28	1.28	1.28	9.28	9.28	9.28	84.66	116.32
LPS - Schedule 48 - 1 - 4 MW (sec)	1.36	1.36	1.36	1.82	1.82	1.82	123.37	132.91
LPS - Schedule 48 - 1 - 4 MW (pri)	1.28	1.28	1.28	1.71	1.71	1.71	115.91	124.88
LPS - Schedule 48 - > 4 MW (sec)	-	-	-	-	-	-	-	-
LPS - Schedule 48 - > 4 MW (pri)	-	-	-	-	-	-	-	-
Total	18.75	18.75	18.75	77.21	77.21	77.21	3,696.84	3,984.72

Circuit Model Cost Assignment

Line statistics for the PacifiCorp service area show that the distribution system is predominately overhead. To calculate the cost of branch construction, miles per branch is calculated by taking the distance per circuit (total line miles / total number of circuits) and dividing it by the number of branches per circuit (7 branches, see figure 1). Next, using an assumption from distribution engineers that the typical outer branches are 25% single phase, the circuit branch length is split between single and three-phase. The total branch construction cost can then be calculated by taking the single and three-phase distances per branch and multiplying them by the one mile construction costs for poles and conductors, as shown in figure 6. Costs are split between demand and commitment by assuming that the cost of constructing the branch with the smallest single-phase conductor and smallest pole is the commitment related portion and all costs above this amount are demand related. Trunk branches 6 and 7 are shown as 100% three-phase. Figure 6 shows the circuit costs per mile, costs for each branch and miles per branch broken out by single and three-phase for Oregon.

Figure 6 – Adjusted Oregon Line Costs per Mile

	Account 364 Pole Cost per Mile			Account 365	Total Line
	Pole Cost	Adjustment	Adjusted	Conductor	Construction
Wire Size	per Mile	Factor	Pole Cost	Cost per Mile	Cost
1 Phase - 1/0 ACSR	$25,517	1.009	$25,758	$12,789	$38,547
3 Phase - 1/0 ACSR	$48,426	1.009	$48,883	$28,548	$77,431
3 Phase - 447 AAC & 4\0 AAC	$54,011	1.009	$54,521	$62,952	$117,473
3 Phase -795 AAC & 477 AAC	$56,143	1.009	$56,673	$110,173	$166,846

	Costs for Branches 1,2,3,4,5		
	1 Phase - 1/0 ACSR	3 Phase - 1/0 ACSR	Total
Poles	$47,499	$167,408	$214,907
Conductors	$23,583	$97,767	$121,350
Total	$71,082	$265,175	$336,257

	Costs for Branch 6	Cost for Branch 7
	3 Phase - 447 AAC & 4\0 AAC	3 Phase -795 AAC & 477 AAC
Poles	$287,255	$298,594
Conductors	$331,674	$580,467
Total	$618,929	$879,060

Miles per Branch	5.27
Single Phase Miles Per Branch	1.84
Three Phase Miles Per Branch	3.42

Customer Circuit Costs
After calculating the cost per mile for single and three-phase construction for all of the branches, we compile the data and create a hypothetical circuit model branch cost sheet, as shown in figure 7. Figure 7 includes the total cost per circuit branch in columns (A) and (B), and the allocation of total cost between commitment and demand in columns (C) through (F) for Oregon.

Figure 7 – Oregon Hypothetical Circuit Model Branch Costs

		(A)	(B)	(C)	(D)	(E)	(F)
		Total Cost		Commitment Cost		Demand Cost	
	Conductors Type	Poles	Conductor	Poles	Conductor	Poles	Conductor
Branch 1							
	1 Phase - 1/0 ACSR	$ 47,499	$ 23,583	$ 47,499	$ 23,583		
	3 Phase - 1/0 ACSR	$ 167,408	$ 97,767	$ 88,212	$ 43,798	$ 79,196	$ 53,969
	Total segment	$ 214,907	$ 121,350	$ 135,711	$ 67,381	$ 79,196	$ 53,969
Branch 2							
	1 Phase - 1/0 ACSR	$ 47,499	$ 23,583	$ 47,499	$ 23,583		
	3 Phase - 1/0 ACSR	$ 167,408	$ 97,767	$ 88,212	$ 43,798	$ 79,196	$ 53,969
	Total Segments	$ 214,907	$ 121,350	$ 135,711	$ 67,381	$ 79,196	$ 53,969
Branch 3							
	1 Phase - 1/0 ACSR	$ 47,499	$ 23,583	$ 47,499	$ 23,583		
	3 Phase - 1/0 ACSR	$ 167,408	$ 97,767	$ 88,212	$ 43,798	$ 79,196	$ 53,969
	Total Segments	$ 214,907	$ 121,350	$ 135,711	$ 67,381	$ 79,196	$ 53,969
Branch 4							
	1 Phase - 1/0 ACSR	$ 47,499	$ 23,583	$ 47,499	$ 23,583		
	3 Phase - 1/0 ACSR	$ 167,408	$ 97,767	$ 88,212	$ 43,798	$ 79,196	$ 53,969
	Total Segments	$ 214,907	$ 121,350	$ 135,711	$ 67,381	$ 79,196	$ 53,969
Branch 5							
	1 Phase - 1/0 ACSR	$ 47,499	$ 23,583	$ 47,499	$ 23,583		
	3 Phase - 1/0 ACSR	$ 167,408	$ 97,767	$ 88,212	$ 43,798	$ 79,196	$ 53,969
	Total Segments	$ 214,907	$ 121,350	$ 135,711	$ 67,381	$ 79,196	$ 53,969
Branch 6							
	3 Phase - 447 AAC & 4\0 AAC	$ 287,255	$ 331,674	$ 135,711	$ 67,381	$ 151,544	$ 264,293
	Total Segments	$ 287,255	$ 331,674	$ 135,711	$ 67,381	$ 151,544	$ 264,293
Branch 7							
	3 Phase -795 AAC & 477 AAC	$ 298,594	$ 580,467	$ 135,711	$ 67,381	$ 162,883	$ 513,086
	Total segment	$ 298,594	$ 580,467	$ 135,711	$ 67,381	$ 162,883	$ 513,086

Cost Sharing Calculation

As mentioned before, one of the critical factors of cost-responsibility is the location of a customer or class on the circuit branches. Customer classes that locate on all branches share cost responsibility for all branches of the circuit including the trunk. Large industrial customers, who locate on the trunk of the circuit, share cost responsibility for only the trunk. Cost responsibility is determined by calculating the percentage of demand, or percentage of customers, by class that share a particular branch of the circuit. The total branch costs are then multiplied by the share percentage, and the branch costs are totaled by class. To calculate the total branch cost, the applicable cost of branches 6 and 7 are assigned to customers on branches 1, 2, 3, 4 and 5. Demand costs calculated in an earlier step are allocated between customer classes at this point. Figure 8 shows this calculation along with the allocation of branch costs to the individual customer classes for Oregon. Demand costs are totaled for each customer class and divided by circuit kW to get demand cost in dollars per kW.

Figure 8 – Oregon Poles Demand Calculations, Cost Assignment

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
	Hypothetical Circuit Branch								
	1	2	3	4	5	6	7		
% customer	14.05%	14.05%	14.05%			57.86%		100.00%	
Branch 6 Cost	$ 21,288	$ 21,288	$ 21,288			$ 87,679		$ 151,544	$ / kW
% customer	0.47%	0.47%	0.47%	1.94%	1.94%	1.94%	92.78%	100.00%	
Branch 7 Cost	$ 766	$ 766	$ 766	$ 3,156	$ 3,156	$ 3,156	$ 151,115	$ 162,883	
Branch Commitment Cost	$ 79,196	$ 79,196	$ 79,196	$ 79,196	$ 79,196				Average
Total	$ 101,251	$ 101,251	$ 101,251	$ 82,352	$ 82,352	$ 90,835	$ 151,115	$ 710,408	$ 178.28
								Total	
								Demand	$ Per
Class Cost per Branch	1	2	3	4	5	6	7	Cost	kW
Res - Schedule 4 (sec)	$ 48,440	$ 48,440	$ 48,440	$ 46,683	$ 46,683	$ 51,491	$ 91,137	$ 381,314	$ 159.69
GS - Schedule 23 - 0-15 kW (sec)	$ 6,233	$ 6,233	$ 6,233	$ 4,494	$ 4,494	$ 4,957	$ 5,796	$ 38,439	$ 243.46
GS - Schedule 23 - 15+ kW (sec)	$ 6,952	$ 6,952	$ 6,952	$ 5,012	$ 5,012	$ 5,529	$ 6,464	$ 42,874	$ 243.46
GS - Schedule 23 - Primary (pri)	$ 25	$ 25	$ 25	$ 18	$ 18	$ 20	$ 23	$ 151	$ 243.46
GS - Schedule 28 - 0-50 kW (sec)	$ 3,041	$ 3,041	$ 3,041	$ 2,049	$ 2,049	$ 2,260	$ 4,840	$ 20,319	$ 161.46
GS - Schedule 28 - 51-100 kW (sec)	$ 4,471	$ 4,471	$ 4,471	$ 3,012	$ 3,012	$ 3,323	$ 7,116	$ 29,876	$ 161.46
GS - Schedule 28 - 100 + kW (sec)	$ 5,710	$ 5,710	$ 5,710	$ 3,847	$ 3,847	$ 4,243	$ 9,088	$ 38,155	$ 161.46
GS - Schedule 28 - Primary (pri)	$ 137	$ 137	$ 137	$ 92	$ 92	$ 102	$ 218	$ 913	$ 161.46
GS - Schedule 30 - 0-300 kW (sec)	$ 788	$ 788	$ 788	$ 545	$ 545	$ 601	$ 2,059	$ 6,115	$ 116.84
GS - Schedule 30 - 300+ kW (sec)	$ 3,882	$ 3,882	$ 3,882	$ 2,683	$ 2,683	$ 2,960	$ 10,138	$ 30,112	$ 116.84
GS - Schedule 30 - Primary (pri)	$ 381	$ 381	$ 381	$ 264	$ 264	$ 291	$ 996	$ 2,958	$ 116.84
Irrigation - Sch 41	$ 6,911	$ 6,911	$ 6,911	$ 9,893	$ 9,893	$ 10,913	$ 3,461	$ 54,893	$ 471.90
LPS - Schedule 48 - 1 - 4 MW (sec)	$ 7,363	$ 7,363	$ 7,363	$ 1,939	$ 1,939	$ 2,138	$ 5,043	$ 33,146	$ 249.38
LPS - Schedule 48 - 1 - 4 MW (pri)	$ 6,917	$ 6,917	$ 6,917	$ 1,821	$ 1,821	$ 2,009	$ 4,738	$ 31,142	$ 249.38
LPS - Schedule 48 - > 4 MW (sec)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LPS - Schedule 48 - > 4 MW (pri)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Check Total	$ 101,251	$ 101,251	$ 101,251	$ 82,352	$ 82,352	$ 90,835	$ 151,115	$ 710,408	

Commitment costs are calculated using a similar method. Commitment costs calculated in an earlier step are allocated to classes using percent of customers on a given branch. Commitment dollars are totaled by customer class then divided by the number of customers in the class to get commitment costs in dollars per customer. Figure 9 shows these calculations for Oregon.

Figure 9–Oregon Poles Commitment Calculations, Cost Assignment

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
	Hypothetical Circuit Branch								
	1	2	3	4	5	6	7		
% customer	14.05%	14.05%	14.05%			57.86%		100.00%	
Branch 6 Cost	$ 37,127	$ 37,127	$ 37,127			$ 152,912		$ 264,293	$ / kW
% customer	0.47%	0.47%	0.47%	1.94%	1.94%	1.94%	92.78%	100.00%	
Branch 7 Cost	$ 2,414	$ 2,414	$ 2,414	$ 9,942	$ 9,942	$ 9,942	$ 476,017	$ 513,086	
Branch Commitment Cost	$ 53,969	$ 53,969	$ 53,969	$ 53,969	$ 53,969				Average
Total	$ 93,510	$ 93,510	$ 93,510	$ 63,911	$ 63,911	$ 162,854	$ 476,017	$ 1,047,223	$ 262.81
								Total	
								Demand	$ Per
Class Cost per Branch	1	2	3	4	5	6	7	Cost	kW
Res - Schedule 4 (sec)	$ 44,737	$ 44,737	$ 44,737	$ 36,229	$ 36,229	$ 92,316	$ 287,085	$ 586,070	$ 245.45
GS - Schedule 23 - 0-15 kW (sec)	$ 5,756	$ 5,756	$ 5,756	$ 3,488	$ 3,488	$ 8,887	$ 18,256	$ 51,387	$ 325.47
GS - Schedule 23 - 15+ kW (sec)	$ 6,421	$ 6,421	$ 6,421	$ 3,890	$ 3,890	$ 9,912	$ 20,363	$ 57,317	$ 325.47
GS - Schedule 23 - Primary (pri)	$ 23	$ 23	$ 23	$ 14	$ 14	$ 35	$ 72	$ 202	$ 325.47
GS - Schedule 28 - 0-50 kW (sec)	$ 2,808	$ 2,808	$ 2,808	$ 1,590	$ 1,590	$ 4,051	$ 15,245	$ 30,900	$ 245.54
GS - Schedule 28 - 51-100 kW (sec)	$ 4,129	$ 4,129	$ 4,129	$ 2,338	$ 2,338	$ 5,957	$ 22,415	$ 45,435	$ 245.54
GS - Schedule 28 - 100 + kW (sec)	$ 5,273	$ 5,273	$ 5,273	$ 2,986	$ 2,986	$ 7,608	$ 28,627	$ 58,026	$ 245.54
GS - Schedule 28 - Primary (pri)	$ 126	$ 126	$ 126	$ 71	$ 71	$ 182	$ 685	$ 1,389	$ 245.54
GS - Schedule 30 - 0-300 kW (sec)	$ 728	$ 728	$ 728	$ 423	$ 423	$ 1,078	$ 6,485	$ 10,593	$ 202.41
GS - Schedule 30 - 300+ kW (sec)	$ 3,586	$ 3,586	$ 3,586	$ 2,083	$ 2,083	$ 5,307	$ 31,934	$ 52,162	$ 202.41
GS - Schedule 30 - Primary (pri)	$ 352	$ 352	$ 352	$ 205	$ 205	$ 521	$ 3,137	$ 5,125	$ 202.41
Irrigation - Sch 41	$ 6,383	$ 6,383	$ 6,383	$ 7,678	$ 7,678	$ 19,565	$ 10,901	$ 64,969	$ 558.52
LPS - Schedule 48 - 1 - 4 MW (sec)	$ 6,800	$ 6,800	$ 6,800	$ 1,505	$ 1,505	$ 3,834	$ 15,886	$ 43,128	$ 324.48
LPS - Schedule 48 - 1 - 4 MW (pri)	$ 6,388	$ 6,388	$ 6,388	$ 1,414	$ 1,414	$ 3,602	$ 14,925	$ 40,519	$ 324.48
LPS - Schedule 48 - > 4 MW (sec)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LPS - Schedule 48 - > 4 MW (pri)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Check Total	$ 93,510	$ 93,510	$ 93,510	$ 63,911	$ 63,911	$ 162,854	$ 476,017	$ 1,047,223	

Large Industrial Customers

Distribution studies have shown that very large industrial customers are not placed on a circuit in the same manner as residential or smaller commercial and industrial customers. Rather the customer is located very close to a substation (the average distance in Oregon is 2/3 of a mile) and has a dedicated circuit for their exclusive use. Since they have a dedicated circuit, they do not share in the costs of other common distribution investments, but they are responsible for the entire cost of the dedicated circuit. Dividing the total cost of a 2/3 of a mile circuit by the customer's kW determines the demand cost in dollars per kW for these customers. Table 10 shows this calculation for Oregon.

Table 10 – Oregon Dedicated Circuit Trunk Costs for Large Customers

	Voltage Delivery				
	Large GS + 4 MW (pri)			Large GS + 4 MW (sec)	
	Poles	Conductor		Poles	Conductor
Construction Cost Per Mile	$ 56,673	$ 110,173		$ 56,673	$ 110,173
Average Trunk Length	0.67	miles		0.67	miles
Total Construction Cost	$ 37,971	$ 73,816		$ 37,971	$ 73,816
Customer Peak Demand	4,256	kW		4,764	kW
Demand Cost $/kW	$8.92	$17.34		$7.97	$15.49

Summary

The final step in the circuit model is to bring the various results together in a single summary page. Table 11 shows the results calculated earlier in the study. Note that the $/customer and $/circuit kW is the distribution investment to serve that customer and not the price that the customer is expected to pay.

Table 11 – Oregon Summary of Results

	Commitment $/Customer		Demand $/Dist. kW		Typical circuit		Demand $/circuit	
Class	Poles	Conductor	Poles	Conductor	Customers	kW	Poles	Conductor
Res - Schedule 4 (sec)	$ 734.13	$ 364.50	$ 159.69	$ 245.45	980.6	2,387.77	$ 381,314	$ 586,070
GS - Schedule 23 - 0-15 kW (sec)	$ 1,158.69	$ 575.29	$ 243.46	$ 325.47	132.5	157.89	$ 38,439	$ 51,387
GS - Schedule 23 - 15+ kW (sec)	$ 1,158.69	$ 575.29	$ 243.46	$ 325.47	27.3	176.10	$ 42,874	$ 57,317
GS - Schedule 23 - Primary (pri)	$ 1,158.69	$ 575.29	$ 243.46	$ 325.47	0.2	0.62	$ 151	$ 202
GS - Schedule 28 - 0-50 kW (sec)	$ 739.44	$ 367.14	$ 161.46	$ 245.54	8.9	125.85	$ 20,319	$ 30,900
GS - Schedule 28 - 51-100 kW (sec)	$ 739.44	$ 367.14	$ 161.46	$ 245.54	6.6	185.04	$ 29,876	$ 45,435
GS - Schedule 28 - 100 + kW (sec)	$ 739.44	$ 367.14	$ 161.46	$ 245.54	3.7	236.32	$ 38,155	$ 58,026
GS - Schedule 28 - Primary (pri)	$ 739.44	$ 367.14	$ 161.46	$ 245.54	0.1	5.66	$ 913	$ 1,389
GS - Schedule 30 - 0-300 kW (sec)	$ 512.16	$ 254.29	$ 116.84	$ 202.41	0.4	52.34	$ 6,115	$ 10,593
GS - Schedule 30 - 300+ kW (sec)	$ 512.16	$ 254.29	$ 116.84	$ 202.41	1.0	257.71	$ 30,112	$ 52,162
GS - Schedule 30 - Primary (pri)	$ 512.16	$ 254.29	$ 116.84	$ 202.41	0.1	25.32	$ 2,958	$ 5,125
Irrigation - Sch 41	$ 2,350.27	$ 1,166.92	$ 471.90	$ 558.52	12.4	116.32	$ 54,893	$ 64,969
LPS - Schedule 48 - 1 - 4 MW (sec)	$ 1,173.53	$ 582.66	$ 249.38	$ 324.48	0.2	132.91	$ 33,146	$ 43,128
LPS - Schedule 48 - 1 - 4 MW (pri)	$ 1,173.53	$ 582.66	$ 249.38	$ 324.48	0.1	124.88	$ 31,142	$ 40,519
Total -	$ 808.97	$ 401.66	$ 178.28	$ 262.81	1,174.3	3,984.7	$ 710,408	$ 1,047,223
Large GS + 4 MW (sec)	$ -	$ -	$ 7.97	$ 15.49	-	4,763.92	$ 37,971	$ 73,816
Large GS + 4 MW (pri)	$ -	$ -	$ 8.92	$ 17.34	-	4,256.39	$ 37,971	$ 73,816
							$ 786,350	$ 1,194,855

Table 1

PacifiCorp
Oregon Marginal Cost Study
Summary of Marginal Costs
Demand & Energy in Mills/kWh
December 2023 Dollars

			(A)	(B)	(C)	(D)	(E)	(F)
			Energy			Demand & Energy		
Line	Description		1 Year	10 Year	20 Year	1 Year	10 Year	20 Year
1	Res - Schedule 4	(sec)	34.51	37.14	38.13	34.51	73.19	74.15
2								
3	GS - Schedule 23							
4	0-15 kW	(sec)	34.51	37.14	38.13	34.51	68.05	69.01
5	15+ kW	(sec)	34.51	37.14	38.13	34.51	68.15	69.11
6	Primary	(pri)	33.98	36.57	37.54	33.98	58.83	59.75
7								
8	GS - Schedule 28							
9	0-50 kW	(sec)	34.51	37.14	38.13	34.51	64.69	65.66
10	51-100 kW	(sec)	34.51	37.14	38.13	34.51	64.01	64.98
11	100 + kW	(sec)	34.51	37.14	38.13	34.51	63.09	64.06
12	Primary	(pri)	33.98	36.57	37.54	33.98	60.09	61.04
13								
14	GS - Schedule 30							
15	0-300 kW	(sec)	34.51	37.14	38.13	34.51	61.22	62.19
16	300+ kW	(sec)	34.51	37.14	38.13	34.51	60.03	61.00
17	Primary	(pri)	33.98	36.57	37.54	33.98	59.43	60.38
18								
19	LPS - Schedule 48							
20	1 - 4 MW	(sec)	34.51	37.14	38.13	34.51	63.98	64.95
21	1 - 4 MW	(pri)	33.98	36.57	37.54	33.98	61.50	62.45
22	> 4 MW	(sec)	34.51	37.14	38.13	34.51	53.14	54.12
23	> 4 MW	(pri)	33.98	36.57	37.54	33.98	52.07	53.02
24	Trans	(trn)	33.08	35.61	36.56	33.08	47.37	48.30
25								
26								
27	Schedule 41- Irrigation	(sec)	34.51	37.14	38.13	34.51	85.12	86.09

Energy costs include both generation and transmission energy-related costs.

Table 2

PacifiCorp
Oregon Marginal Cost Study
Summary of Marginal Costs
Commitment and Billing in $ / Customer / Month
December 2023 Dollars

			(A)	(B)
Line	Description		1 Year	10 & 20 Year
1	Res - Schedule 4	(sec)	$11.91	$28.85
2				
3	GS - Schedule 23			
4	0-15 kW	(sec)	14.10	43.93
5	15+ kW	(sec)	22.40	56.95
6	Primary	(pri)	100.52	116.01
7				
8	GS - Schedule 28			
9	0-50 kW	(sec)	25.63	94.56
10	51-100 kW	(sec)	26.58	103.56
11	100 + kW	(sec)	55.26	137.78
12	Primary	(pri)	102.88	112.77
13				
14	GS - Schedule 30			
15	0-300 kW	(sec)	65.97	155.31
16	300+ kW	(sec)	97.99	187.59
17	Primary	(pri)	113.56	120.41
18				
19	LPS - Schedule 48			
20	1 - 4 MW	(sec)	331.79	430.23
21	1 - 4 MW	(pri)	183.00	198.69
22	> 4 MW	(sec)	331.79	414.54
23	> 4 MW	(pri)	183.00	183.00
24	Trans	(trn)	1,743.47	1,743.47
25				
26				
27	Schedule 41- Irrigation	(sec)	6.85	106.38

Footnote:
Short-run commitment and billing costs include the cost of metering, meter overhead, maintenance, service drops, service drop overhead and maintenance, customer accounting, informational expenses, and billing expenses.

Table 3

PacifiCorp
Oregon Marginal Cost Study
20 Year Marginal Cost
December 2023 Dollars

Line	Calculation Component	Class	Units Description / Function	Total	(A) Residential (sec)	(B) General Service - Schedule 23 0-15 kW (sec)	(C) General Service - Schedule 23 15+ kW (sec)	(D) General Service - Schedule 23 Primary (pri)	(E) General Service - Schedule 28 0-50 kW (sec)	(F) General Service - Schedule 28 51-100 kW (sec)	(G) General Service - Schedule 28 100 + kW (sec)	(H) General Service - Schedule 28 Primary (pri)	(I) General Service - Schedule 30 0-300 kW (sec)	(J) General Service - Schedule 30 300+ kW (sec)	(K) General Service - Schedule 30 Primary (pri)	(L) Large Power Service - Schedule 48 1 - 4 MW (sec)	(M) Large Power Service - Schedule 48 1 - 4 MW (pri)	(N) Large Power Service - Schedule 48 > 4 MW (sec)	(O) Large Power Service - Schedule 48 > 4 MW (pri)	(P) Large Power Service - Schedule 48 Trn (trn)	(Q) Irrg - Sch 41 (sec)	(R) Lighting Schs 15, 51, 53, 54 (sec)
1	Units	Demand	Peak MW @ Input-System		1,152	92	100	0	73	108	138	4	30	148	15	75	70	5	125	186	38	
2	Units	Demand	Peak MW @ Input-Distribution		1,373	91	101	0	72	106	136	3	30	148	14	76	71	5	128	-	67	
3	Units	Demand	Peak MW @ Input-Transformer		3,702	455	282	-	292	482	379	-	69	259	-	130	-	9	-	-	229	
4																						
5	Units	Energy	Annual MWh @ Input		6,082,593	588,687	635,298	3,533	472,029	718,357	934,868	25,303	206,473	1,070,906	104,635	547,595	531,645	41,798	1,024,837	1,599,365	284,558	
6																						
7	Units	Customer	Average		535,059	69,806	14,408	115	4,819	3,562	2,012	69	213	531	53	92	61	1	28	8	4,356	
8	Units	Customer	Annual		535,059	69,806	14,408	115	4,819	3,562	2,012	69	213	531	53	92	61	1	28	8	7,997	
9																						
10																						
11	$/Unit	Demand	Generation ($/System Peak kW)		$93.29	$93.29	$93.29	$93.29	$93.29	$93.29	$93.29	$93.29	$93.29	$93.29	$93.29	$93.29	$93.29	$93.29	$93.29	$93.29	$93.29	
12	$/Unit	Demand	Transmission ($/System Peak kW)		$4.38	$4.38	$4.38	$4.38	$4.38	$4.38	$4.38	$4.38	$4.38	$4.38	$4.38	$4.38	$4.38	$4.38	$4.38	$4.38	$4.38	
13	$/Unit	Demand	Dist-Poles ($/Dist. kW)		$17.12	$26.11	$26.11	$26.11	$17.30	$17.30	$17.30	$17.30	$12.53	$12.53	$12.53	$26.73	$26.73	$0.86	$0.96	$0.00	$50.59	
14	$/Unit	Demand	Dist-Cond ($/Dist. kW)		$26.31	$34.90	$34.90	$34.90	$26.33	$26.33	$26.33	$26.33	$21.70	$21.70	$21.70	$34.78	$34.78	$1.67	$1.86	$0.00	$59.88	
15	$/Unit	Demand	Dist-Substation ($/Dist. kW)		$18.40	$18.40	$18.40	$18.40	$18.40	$18.40	$18.40	$18.40	$18.40	$18.40	$18.40	$18.40	$18.40	$18.40	$18.40	$0.00	$18.40	
16	$/Unit	Demand	Dist-Transformers ($/Xfmr kW)		$1.48	$1.48	$1.48	$0.00	$1.48	$1.48	$1.48	$0.00	$1.48	$1.48	$0.00	$1.48	$0.00	$1.48	$0.00	$0.00	$1.48	
17																						
18	$/Unit	Energy	Generation Energy @ Input ($/kWh)		$0.03532	$0.03532	$0.03532	$0.03532	$0.03532	$0.03532	$0.03532	$0.03532	$0.03532	$0.03532	$0.03532	$0.03532	$0.03532	$0.03532	$0.03532	$0.03532	$0.03532	
19	$/Unit	Energy	Transmission Energy @ Input ($/kWh)		$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	
20																						
21	$/Unit	Customer	Dist-Poles ($/Customer)		$78.70	$124.24	$124.24	$124.24	$79.28	$79.28	$79.28	$79.28	$54.92	$54.92	$54.92	$125.82	$125.82	$0.00	$0.00	$0.00	$251.98	
22	$/Unit	Customer	Dist-Conductor ($/Customer)		$39.08	$61.68	$61.68	$61.68	$39.37	$39.37	$39.37	$39.37	$27.27	$27.27	$27.27	$62.47	$62.47	$0.00	$0.00	$0.00	$125.12	
23	$/Unit	Customer	Dist-Transformers ($/Customer)		$85.45	$172.10	$228.58	$0.00	$708.48	$805.13	$871.54	$0.00	$989.88	$992.99	$0.00	$992.99	$0.00	$992.99	$0.00	$0.00	$817.24	
24	$/Unit	Customer	Dist-Service Drop ($/Customer)		$75.76	$102.46	$198.46	$0.00	$205.20	$214.31	$415.31	$0.00	$415.15	$799.21	$0.00	$2,733.92	$0.00	$2,733.92	$0.00	$0.00	$0.00	
25	$/Unit	Customer	Meters ($/Customer)		$23.21	$24.69	$28.37	$1,164.18	$31.92	$34.16	$177.40	$1,164.18	$177.96	$178.19	$1,164.18	$215.74	$1,164.18	$215.74	$1,164.18	$19,889.86	$34.18	
26	$/Unit	Customer	Meter Reading ($/Customer)		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
27	$/Unit	Customer	Billing & Collections ($/Customer)		$25.10	$30.35	$30.35	$30.35	$35.21	$35.21	$35.21	$35.21	$35.21	$35.21	$35.21	$290.78	$290.78	$290.78	$290.78	$290.78	$30.33	
28	$/Unit	Customer	Uncollectables ($/Customer)		$9.64	$2.49	$2.49	$2.49	$25.02	$25.02	$25.02	$25.02	$148.58	$148.58	$148.58	$696.73	$696.73	$696.73	$696.73	$696.73	$8.29	
29	$/Unit	Customer	Customer Service / Other ($/Customer)		$9.26	$9.19	$9.19	$9.19	$10.20	$10.20	$10.20	$10.20	$14.74	$14.74	$14.74	$44.26	$44.26	$44.26	$44.26	$44.26	$9.40	
30																						
31																						
32	$000	Demand	Generation	$220,002	$107,503	$8,554	$9,332	$44	$6,793	$10,074	$12,856	$344	$2,783	$13,848	$1,425	$6,976	$6,491	$474	$11,655	$17,333	$3,516	$0
33	$000	Demand	Transmission	$10,329	$5,047	$402	$438	$2	$319	$473	$604	$16	$131	$650	$67	$328	$305	$22	$547	$814	$165	$0
34	$000	Demand	Dist-Poles	$43,954	$23,495	$2,370	$2,643	$9	$1,252	$1,841	$2,351	$56	$377	$1,857	$180	$2,043	$1,894	$4	$123	$0	$3,383	$77
35	$000	Demand	Dist-Conductor	$64,852	$36,118	$3,168	$3,533	$12	$1,905	$2,800	$3,577	$85	$653	$3,215	$312	$2,658	$2,464	$9	$238	$0	$4,004	$103
36	$000	Demand	Dist-Substations	$44,587	$25,258	$1,670	$1,863	$6	$1,331	$1,957	$2,500	$59	$554	$2,726	$264	$1,406	$1,304	$96	$2,363	$0	$1,230	$0
37	$000	Demand	Dist-Transformers	$9,372	$5,495	$675	$419	$0	$434	$716	$562	$0	$102	$385	$0	$192	$0	$13	$0	$0	$341	$37
38	$000	Demand	Total Demand	$393,096	$202,915	$16,837	$18,228	$74	$12,034	$17,862	$22,449	$559	$4,600	$22,681	$2,248	$13,602	$12,458	$619	$14,926	$18,147	$12,640	$218
39																						
40	$000	Energy	Generation	$526,179	$214,837	$20,792	$22,439	$125	$16,672	$25,372	$33,020	$894	$7,293	$37,824	$3,696	$19,341	$18,778	$1,476	$36,197	$56,490	$10,051	$883
41	$000	Energy	Transmission	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
42	$000	Energy	Total Energy	$526,179	$214,837	$20,792	$22,439	$125	$16,672	$25,372	$33,020	$894	$7,293	$37,824	$3,696	$19,341	$18,778	$1,476	$36,197	$56,490	$10,051	$883
43																						
44	$000	Customer	Dist-Poles	$55,496	$42,111	$8,672	$1,790	$14	$382	$282	$160	$5	$12	$29	$3	$12	$8	$0	$0	$0	$2,015	$0
45	$000	Customer	Dist-Conductor	$27,553	$20,908	$4,305	$889	$7	$190	$140	$79	$3	$6	$14	$1	$6	$4	$0	$0	$0	$1,001	$0
46	$000	Customer	Dist-Transformers	$76,429	$45,720	$12,013	$3,293	$0	$3,414	$2,868	$1,754	$0	$211	$527	$0	$91	$0	$1	$0	$0	$6,535	$0
47	$000	Customer	Dist-Lighting	$6,326	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,326
48	$000	Customer	Dist-Service Drop	$53,903	$40,536	$7,153	$2,859	$0	$989	$763	$836	$0	$88	$424	$0	$252	$0	$3	$0	$0	$0	$0
49	$000	Customer	Meters	$16,150	$12,418	$1,724	$409	$134	$154	$122	$357	$80	$38	$95	$62	$20	$71	$0	$33	$159	$273	$2.52
50	$000	Customer	Meter Reading	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
51	$000	Customer	Billing & Collections	$16,770	$13,430	$2,119	$437	$3	$170	$125	$71	$2	$7	$19	$2	$27	$18	$0	$8	$2	$132	$196
52	$000	Customer	Uncollectables	$5,914	$5,155	$174	$36	$0	$121	$89	$50	$2	$32	$79	$8	$64	$43	$1	$20	$6	$36	$0
53	$000	Customer	Customer Service / Other	$5,964	$4,955	$642	$132	$1	$49	$36	$21	$1	$3	$8	$1	$4	$3	$0	$1	$0	$41	$66
54	$000	Customer	Total Customer (Commitment & Billing)	$264,503	$185,235	$36,801	$9,846	$160	$5,468	$4,426	$3,326	$93	$397	$1,195	$77	$475	$145	$5	$61	$167	$10,034	$6,590
55																						
56																						
57			Total Revenue @ Full MC ($000)																			
58			Generation	$746,181	$322,340	$29,346	$31,771	$169	$23,465	$35,447	$45,875	$1,238	$10,076	$51,673	$5,121	$26,317	$25,269	$1,951	$47,852	$73,823	$13,567	$883
59			Transmission	$10,329	$5,047	$402	$438	$2	$319	$473	$604	$16	$131	$650	$67	$328	$305	$22	$547	$814	$165	$0
60			Distribution	$376,144	$239,641	$40,026	$17,289	$49	$9,897	$11,368	$11,817	$207	$2,002	$9,178	$760	$6,659	$5,673	$126	$2,724	$0	$18,509	$218
61			Distribution-Lighting	$6,326	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,326
62			Customer - Billing	$16,770	$13,430	$2,119	$437	$3	$170	$125	$71	$2	$7	$19	$2	$27	$18	$0	$8	$2	$132	$196
63			Customer - Metering	$16,150	$12,418	$1,724	$409	$134	$154	$122	$357	$80	$38	$95	$62	$20	$71	$0	$33	$159	$273	$3
64			Customer - Other	$5,964	$4,955	$642	$132	$1	$49	$36	$21	$1	$3	$8	$1	$4	$3	$0	$1	$0	$41	$66
65			Total Revenue (less Uncollectables)	$1,177,864	$597,832	$74,257	$50,476	$358	$34,053	$47,571	$58,745	$1,545	$12,258	$61,622	$6,012	$33,354	$31,338	$2,100	$51,165	$74,798	$32,688	$7,691
66																						
67			Customer - Uncollectables	$5,914	$5,155	$174	$36	$0	$121	$89	$50	$2	$32	$79	$8	$64	$43	$1	$20	$6	$36	$0
68			Total Revenue	$1,183,778	$602,987	$74,431	$50,512	$359	$34,174	$47,660	$58,795	$1,546	$12,289	$61,701	$6,020	$33,418	$31,381	$2,100	$51,185	$74,804	$32,724	$7,691

Table 4

PacifiCorp
Oregon Marginal Cost Study
Summary of Marginal Generation Costs in Nominal Dollars

	(A) (B) + (C)	(B)	(C)	(D)
Year	Resource Cost (Mills/kWh)	Energy Only (Mills/kWh)	Capacity Only (Mills/kWh)	Capacity Only ($/kW)
2023	47.10	31.96	15.14	93.53
2024	47.87	32.38	15.49	95.66
2025	50.42	34.58	15.84	97.84
2026	52.22	36.02	16.20	100.07
2027	53.99	37.42	16.57	102.36
2028	56.18	39.23	16.95	104.70
2029	59.13	41.79	17.34	107.09
2030	60.88	43.14	17.74	109.53
2031	62.56	44.42	18.14	112.03
2032	63.65	45.10	18.55	114.58
2033	65.79	46.81	18.98	117.19
2034	66.77	47.36	19.41	119.86
2035	67.72	47.87	19.85	122.60
2036	69.02	48.72	20.30	125.39
2037	70.76	49.99	20.77	128.25
2038	72.30	51.06	21.24	131.17
2039	74.95	53.22	21.73	134.17
2040	77.47	55.25	22.22	137.23
2041	79.25	56.52	22.73	140.36
2042	81.06	57.81	23.25	143.56

	Mills/kWh	Mills/kWh	Mills/kWh	$/kW
2023 (1 Year)	47.10	31.96	15.14	93.53
2023 - 2027 (5 Year, Short Run)				
Sum of PV Costs @ 7.21%	218.87	149.81	69.06	426.56
Annual Cost @ 21.92%	47.98	32.84	15.14	93.50
2023 - 2032 (10 Year, Medium Run)				
Sum of PV Costs @ 7.21%	404.72	281.07	123.65	763.68
Annual Cost @ 12.24%	49.53	34.40	15.13	93.47
2023 - 2042 (20 Year, Long Run)				
Sum of PV Costs @ 7.21%	670.51	469.63	200.88	1,240.61
Annual Cost @ 7.52%	50.43	35.32	15.11	93.29

Table 5

PacifiCorp
Oregon Marginal Cost Study
Marginal Cost of
Transmission Investment and Associated Expenses

Line	Item	$	
1	Growth Related Investments - (2022 to 2026 in $000s)	$158,702	
2			
3	System Growth MW from 2022 to 2026	2,879	
4			
5	Marginal Investment (line 1/line 3)	$55.13	/ kW
6			
7	Annualized Investment @ 6.16%	3.40	/ kW
8	Admin. & General Factor @ 0.60%	0.33	
9	Annual O&M Expenses @ 1.176%	0.65	/ kW
10	Annualized Marginal Cost	$4.38	/ kW
11			
12	Marginal Cost of Demand-Related Transmission	$4.38	/ kW
13			
14	Marginal Cost of Energy-Related Transmission (Line 10 - Line 12)	$0.00	/ kW
15	Marginal Cost of Energy-Related Transmission	$0.00000	/ kWh
16	$0.00 / (8760 x 77.45% LF))		

Table 6

PacifiCorp
Oregon Marginal Cost Study
Marginal Distribution & Billing Costs
2023 Dollars

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)
		Residential	General Service - Schedule 23			General Service - Schedule 28				General Service - Schedule 30			Large Power Service - Schedule 48					Irrg Sch 41
			0-15 kW	15+ kW	Primary	0-50 kW	51-100 kW	100 + kW	Primary	0-300 kW	300+ kW	Primary	1 - 4 MW	1 - 4 MW	> 4 MW	> 4 MW	Trans	
Line	Description	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)
1	Demand Costs ($/kW)																	
2																		
3	Dist-Poles	$11.80	$18.00	$18.00	$18.00	$11.93	$11.93	$11.93	$11.93	$8.64	$8.64	$8.64	$18.43	$18.43	$0.59	$0.66	$0.00	$34.88
4	Dist-Conductors	$18.14	$24.06	$24.06	$24.06	$18.15	$18.15	$18.15	$18.15	$14.96	$14.96	$14.96	$23.98	$23.98	$1.15	$1.28	$0.00	$41.28
5	Dist-Substation	$12.69	$12.69	$12.69	$12.69	$12.69	$12.69	$12.69	$12.69	$12.69	$12.69	$12.69	$12.69	$12.69	$12.69	$12.69	$0.00	$12.69
6	Dist. O&M @ 45.05% of Investment	$19.20	$24.66	$24.66	$24.66	$19.27	$19.27	$19.27	$19.27	$16.35	$16.35	$16.35	$24.82	$24.82	$6.50	$6.59	$0.00	$40.02
7	Total $/Dist. kW	$61.83	$79.41	$79.41	$79.41	$62.03	$62.03	$62.03	$62.03	$52.63	$52.63	$52.63	$79.92	$79.92	$20.92	$21.21	$0.00	$128.87
8																		
9	Dist-Transformers	$1.02	$1.02	$1.02	$0.00	$1.02	$1.02	$1.02	$0.00	$1.02	$1.02	$0.00	$1.02	$0.00	$1.02	$0.00	$0.00	$1.02
10	Dist. O&M @ 45.05% of Investment	$0.46	$0.46	$0.46	$0.00	$0.46	$0.46	$0.46	$0.00	$0.46	$0.46	$0.00	$0.46	$0.00	$0.46	$0.00	$0.00	$0.46
11	Total $/Transformer kW	$1.48	$1.48	$1.48	$0.00	$1.48	$1.48	$1.48	$0.00	$1.48	$1.48	$0.00	$1.48	$0.00	$1.48	$0.00	$0.00	$1.48
12																		
13																		
14																		
15	Customer Costs ($/Customer)																	
16																		
17	Commitment																	
18	Dist-Poles	$54.26	$85.65	$85.65	$85.65	$54.66	$54.66	$54.66	$54.66	$37.86	$37.86	$37.86	$86.74	$86.74	$0.00	$0.00	$0.00	$173.72
19	Dist-Conductors	$26.94	$42.52	$42.52	$42.52	$27.14	$27.14	$27.14	$27.14	$18.80	$18.80	$18.80	$43.07	$43.07	$0.00	$0.00	$0.00	$86.26
20	Dist-Transformers	$58.91	$118.65	$157.59	$0.00	$488.44	$555.07	$600.86	$0.00	$682.44	$684.58	$0.00	$684.58	$0.00	$684.58	$0.00	$0.00	$563.42
21	Dist. O&M @ 45.05% of Investment	$63.12	$111.19	$128.73	$57.74	$256.89	$286.91	$307.54	$36.85	$332.96	$333.93	$25.53	$366.88	$58.48	$308.41	$0.00	$0.00	$370.94
22	Total Commitment	$203.23	$358.01	$414.49	$185.91	$827.13	$923.78	$990.19	$118.65	$1,072.06	$1,075.17	$82.19	$1,181.28	$188.29	$992.99	$0.00	$0.00	$1,194.34
23	Monthly Commitment	$16.94	$29.83	$34.54	$15.49	$68.93	$76.98	$82.52	$9.89	$89.34	$89.60	$6.85	$98.44	$15.69	$82.75	$0.00	$0.00	$99.53
24																		
25	Billing																	
26	Dist-Service Drop	$52.23	$70.64	$136.82	$0.00	$141.47	$147.75	$286.32	$0.00	$286.21	$550.99	$0.00	$1,884.81	$0.00	$1,884.81	$0.00	$0.00	$0.00
27	Dist. O&M @ 45.05% of Investment	$23.53	$31.82	$61.64	$0.00	$63.73	$66.56	$128.99	$0.00	$128.94	$248.22	$0.00	$849.11	$0.00	$849.11	$0.00	$0.00	$0.00
28	Meter	$13.94	$14.83	$17.04	$699.25	$19.17	$20.52	$106.55	$699.25	$106.89	$107.03	$699.25	$129.58	$699.25	$129.58	$699.25	$11,946.58	$20.53
29	Meter O&M @ 66.49% of Investment	$9.27	$9.86	$11.33	$464.93	$12.75	$13.64	$70.85	$464.93	$71.07	$71.16	$464.93	$86.16	$464.93	$86.16	$464.93	$7,943.28	$13.65
30	Meter Reading	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
31	Billing & Collections	$25.10	$30.35	$30.35	$30.35	$35.21	$35.21	$35.21	$35.21	$35.21	$35.21	$35.21	$290.78	$290.78	$290.78	$290.78	$290.78	$30.33
32	Uncollectables	$9.64	$2.49	$2.49	$2.49	$25.02	$25.02	$25.02	$25.02	$148.58	$148.58	$148.58	$696.73	$696.73	$696.73	$696.73	$696.73	$8.29
33	Customer Service / Other	$9.26	$9.19	$9.19	$9.19	$10.20	$10.20	$10.20	$10.20	$14.74	$14.74	$14.74	$44.26	$44.26	$44.26	$44.26	$44.26	$9.40
34	Total Billing	$142.97	$169.19	$268.86	$1,206.21	$307.55	$318.91	$663.13	$1,234.61	$791.63	$1,175.93	$1,362.71	$3,981.44	$2,195.96	$3,981.44	$2,195.96	$20,921.64	$82.21
35	Monthly Billing	$11.91	$14.10	$22.40	$100.52	$25.63	$26.58	$55.26	$102.88	$65.97	$97.99	$113.56	$331.79	$183.00	$331.79	$183.00	$1,743.47	$6.85
36																		
37	Total Customer (Commitment & Billing)	$346.20	$527.19	$683.35	$1,392.12	$1,134.68	$1,242.69	$1,653.33	$1,353.26	$1,863.70	$2,251.10	$1,444.89	$5,162.71	$2,384.25	$4,974.42	$2,195.96	$20,921.64	$1,276.55
38	Monthly Customer (Commitment & Billing)	$28.85	$43.93	$56.95	$116.01	$94.56	$103.56	$137.78	$112.77	$155.31	$187.59	$120.41	$430.23	$198.69	$414.54	$183.00	$1,743.47	$106.38
39																		

Table 7

PacifiCorp
Oregon Marginal Cost Study
20 Year Demand Costs Divided by Billing kW
December 2023 Dollars

			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)
			Residential	General Service - Schedule 23			General Service - Schedule 28				General Service - Schedule 30			Large Power Service - Schedule 48					Irrg - Sch 41
				0-15 kW	15+ kW		0-50 kW	51-100 kW	100 + kW	Primary	0-300 kW	300+ kW	Primary	1 - 4 MW	1 - 4 MW	> 4 MW	> 4 MW	Trn	
Line	Units Description / Function	Total	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)
1	Marginal Cost ($000)																		
2																			
3	Generation	$220,002	$107,503	$8,554	$9,332	$44	$6,793	$10,074	$12,856	$344	$2,783	$13,848	$1,425	$6,976	$6,491	$474	$11,655	$17,333	$3,516
4	Transmission	$10,329	$5,047	$402	$438	$2	$319	$473	$604	$16	$131	$650	$67	$328	$305	$22	$547	$814	$165
5	Dist-Poles, Wire, Sub	$153,213	$84,870	$7,207	$8,039	$28	$4,488	$6,599	$8,427	$199	$1,584	$7,797	$756	$6,106	$5,661	$109	$2,724	$0	$8,618
6	Dist-Transformers	$9,334	$5,495	$675	$419	$0	$434	$716	$562	$0	$102	$385	$0	$192	$0	$13	$0	$0	$341
7																			
8	Average Billing kW @ Sales	8,497,531	5,094,228	598,673	371,428	5,687	269,617	444,697	349,255	12,225	63,411	239,143	24,614	119,399	146,695	8,225	229,520	309,205	211,511
9																			
10	Generation ($/kW)		$21.10	$14.29	$25.12	$7.70	$25.20	$22.65	$36.81	$28.14	$43.90	$57.91	$57.89	58.43	44.25	57.66	50.78	56.06	16.62
11	Transmission ($/kW)		$0.99	$0.67	$1.18	$0.36	$1.18	$1.06	$1.73	$1.32	$2.06	$2.72	$2.72	2.74	2.08	2.71	2.38	2.63	0.78
12	Dist-Poles, Wire, Sub ($/kW)		$16.66	$12.04	$21.64	$4.92	$16.64	$14.84	$24.13	$16.29	$24.97	$32.61	$30.71	51.14	38.59	13.29	11.87	0.00	40.74
13	Dist-Transformers ($/kW)		$1.08	$1.13	$1.13	$0.00	$1.61	$1.61	$1.61	$0.00	$1.61	$1.61	$0.00	1.61	0.00	1.61	0.00	0.00	1.61
14																			
15	Total Demand Related		$39.83	$28.12	$49.08	$12.98	$44.63	$40.17	$64.28	$45.75	$72.54	$94.84	$91.32	$113.92	$84.92	$75.26	$65.03	$58.69	$59.76
16	Monthly Demand Related		$3.32	$2.34	$4.09	$1.08	$3.72	$3.35	$5.36	$3.81	$6.04	$7.90	$7.61	$9.49	$7.08	$6.27	$5.42	$4.89	$4.98

Table 8

PacifiCorp
Oregon Marginal Cost Study
Marginal Cost Percentage
December 2023 Dollars

		(A)	(B)	(C)
Line	Description	Marginal Cost (000s)	Mills / kWh	% of Total
1	Demand Related Marginal Cost			
2	Generation	$220,002	15.84	18.7%
3	Transmission	$10,329	0.74	0.9%
4	Dist. Poles, Cond., Subst.	$153,213	11.03	13.0%
5	Dist. Transformers	$9,372	0.67	0.8%
6	Total Demand Related	$392,916	28.28	33.4%
7				
8	Energy Related Marginal Cost			
9	Generation	$526,179	37.89	44.7%
10	Transmission	$0	0.00	0.0%
11	Total Energy Related	$526,179	37.89	44.7%
12				
13	Commitment & Billing			
14	Commitment	$159,477	11.48	13.5%
15	Billing	$98,701	7.11	8.4%
16	Total Commitment & Billing	$258,178	18.59	21.9%
17				
18				
19	TOTAL MARGINAL COST	$1,177,272	84.76	100.0%
20				
21				
22		Note: Total MWh @ Sales =	13,886,900	

10 Year MC

PacifiCorp
Oregon Marginal Cost Study
10 Year Marginal Cost
December 2023 Dollars

					(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)
					Residential	General Service - Schedule 23			General Service - Schedule 28				General Service - Schedule 30			Large Power Service - Schedule 48					Irrg - Sch 41
	Calculation					0-15 kW	15+ kW	Primary	0-50 kW	51-100 kW	100 + kW	Primary	0-300 kW	300+ kW	Primary	1 - 4 MW	1 - 4 MW	> 4 MW	> 4 MW	Trn	
Line	Component	Class	Units Description / Function	Total	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)
1	Units	Demand	Peak MW @ Input-System		1,152	92	100	0	73	108	138	4	30	148	15	75	70	5	125	186	38
2	Units	Demand	Peak MW @ Input-Distribution		1,373	91	101	0	72	106	136	3	30	148	14	76	71	5	128	-	67
3	Units	Demand	Peak MW @ Input-Transformer		3,702	455	282	-	292	482	379	-	69	259	-	130	-	9	-	-	229
4																					
5	Units	Energy	Annual MWh @ Input		6,082,593	588,687	635,298	3,533	472,029	718,357	934,868	25,303	206,473	1,070,906	104,635	547,595	531,645	41,798	1,024,837	1,599,365	284,558
6																					
7	Units	Customer	Average		535,059	69,806	14,408	115	4,819	3,562	2,012	69	213	531	53	92	61	1	28	8	4,356
8	Units	Customer	Annual		535,059	69,806	14,408	115	4,819	3,562	2,012	69	213	531	53	92	61	1	28	8	7,997
9																					
10																					
11	$/Unit	Demand	Generation ($/System Peak kW)		$93.47	$93.47	$93.47	$93.47	$93.47	$93.47	$93.47	$93.47	$93.47	$93.47	$93.47	$93.47	$93.47	$93.47	$93.47	$93.47	$93.47
12	$/Unit	Demand	Transmission ($/System Peak kW)		$4.38	$4.38	$4.38	$4.38	$4.38	$4.38	$4.38	$4.38	$4.38	$4.38	$4.38	$4.38	$4.38	$4.38	$4.38	$4.38	$4.38
13	$/Unit	Demand	Dist-Poles ($/Dist. kW)		$17.12	$26.11	$26.11	$26.11	$17.30	$17.30	$17.30	$17.30	$12.53	$12.53	$12.53	$26.73	$26.73	$0.86	$0.96	$0.00	$50.59
14	$/Unit	Demand	Dist-Cond ($/Dist. kW)		$26.31	$34.90	$34.90	$34.90	$26.33	$26.33	$26.33	$26.33	$21.70	$21.70	$21.70	$34.78	$34.78	$1.67	$1.86	$0.00	$59.88
15	$/Unit	Demand	Dist-Substation ($/Dist. kW)		$18.40	$18.40	$18.40	$18.40	$18.40	$18.40	$18.40	$18.40	$18.40	$18.40	$18.40	$18.40	$18.40	$18.40	$18.40	$0.00	$18.40
16	$/Unit	Demand	Dist-Transformers ($/Xfmr kW)		$1.48	$1.48	$1.48	$0.00	$1.48	$1.48	$1.48	$0.00	$1.48	$1.48	$0.00	$1.48	$0.00	$1.48	$0.00	$0.00	$1.48
17																					
18	$/Unit	Energy	Generation Energy @ Input ($/kWh)		$0.03440	$0.03440	$0.03440	$0.03440	$0.03440	$0.03440	$0.03440	$0.03440	$0.03440	$0.03440	$0.03440	$0.03440	$0.03440	$0.03440	$0.03440	$0.03440	$0.03440
19																					
20																					
21	$/Unit	Customer	Dist-Poles ($/Customer)		$78.70	$124.24	$124.24	$124.24	$79.28	$79.28	$79.28	$79.28	$54.92	$54.92	$54.92	$125.82	$125.82	$0.00	$0.00	$0.00	$251.98
22	$/Unit	Customer	Dist-Conductor ($/Customer)		$39.08	$61.68	$61.68	$61.68	$39.37	$39.37	$39.37	$39.37	$27.27	$27.27	$27.27	$62.47	$62.47	$0.00	$0.00	$0.00	$125.12
23	$/Unit	Customer	Dist-Transformers ($/Customer)		$85.45	$172.10	$228.58	$0.00	$708.48	$805.13	$871.54	$0.00	$989.88	$992.99	$0.00	$992.99	$0.00	$992.99	$0.00	$0.00	$817.24
24	$/Unit	Customer	Dist-Service Drop ($/Customer)		$75.76	$102.46	$198.46	$0.00	$205.20	$214.31	$415.31	$0.00	$415.15	$799.21	$0.00	$2,733.92	$0.00	$2,733.92	$0.00	$0.00	$0.00
25	$/Unit	Customer	Meters ($/Customer)		$23.21	$24.69	$28.37	$1,164.18	$31.92	$34.16	$177.40	$1,164.18	$177.96	$178.19	$1,164.18	$215.74	$1,164.18	$215.74	$1,164.18	$19,889.86	$34.18
26	$/Unit	Customer	Meter Reading ($/Customer)		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
27	$/Unit	Customer	Billing & Collections ($/Customer)		$25.10	$30.35	$30.35	$30.35	$35.21	$35.21	$35.21	$35.21	$35.21	$35.21	$35.21	$290.78	$290.78	$290.78	$290.78	$290.78	$30.33
28	$/Unit	Customer	Uncollectables ($/Customer)		$9.64	$2.49	$2.49	$2.49	$25.02	$25.02	$25.02	$25.02	$148.58	$148.58	$148.58	$696.73	$696.73	$696.73	$696.73	$696.73	$8.29
29	$/Unit	Customer	Customer Service / Other ($/Customer)		$9.26	$9.19	$9.19	$9.19	$10.20	$10.20	$10.20	$10.20	$14.74	$14.74	$14.74	$44.26	$44.26	$44.26	$44.26	$44.26	$9.40
30																					
31																					
32	$000	Demand	Generation	$220,427	$107,710	$8,570	$9,350	$44	$6,806	$10,094	$12,881	$345	$2,789	$13,875	$1,428	$6,989	$6,504	$475	$11,677	$17,367	$3,523
33	$000	Demand	Transmission	$10,330	$5,047	$402	$438	$2	$319	$473	$604	$16	$131	$650	$67	$328	$305	$22	$547	$814	$165
34	$000	Demand	Dist-Poles	$43,877	$23,495	$2,370	$2,643	$9	$1,252	$1,841	$2,351	$56	$377	$1,857	$180	$2,043	$1,894	$4	$123	$0	$3,383
35	$000	Demand	Dist-Conductor	$64,749	$36,118	$3,168	$3,533	$12	$1,905	$2,800	$3,577	$85	$653	$3,215	$312	$2,658	$2,464	$9	$238	$0	$4,004
36	$000	Demand	Dist-Substations	$44,587	$25,258	$1,670	$1,863	$6	$1,331	$1,957	$2,500	$59	$554	$2,726	$264	$1,406	$1,304	$96	$2,363	$0	$1,230
37	$000	Demand	Dist-Transformers	$9,334	$5,495	$675	$419	$0	$434	$716	$562	$0	$102	$385	$0	$192	$0	$13	$0	$0	$341
38	$000	Demand	Total Demand	$393,304	$203,122	$16,854	$18,246	$74	$12,047	$17,882	$22,474	$560	$4,606	$22,707	$2,251	$13,616	$12,470	$620	$14,948	$18,181	$12,646
39																					
40	$000	Energy	Generation	$511,613	$209,241	$20,251	$21,854	$122	$16,238	$24,711	$32,159	$870	$7,103	$36,839	$3,599	$18,837	$18,289	$1,438	$35,254	$55,018	$9,789
41	$000	Energy	Transmission	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
42	$000	Energy	Total Energy	$511,613	$209,241	$20,251	$21,854	$122	$16,238	$24,711	$32,159	$870	$7,103	$36,839	$3,599	$18,837	$18,289	$1,438	$35,254	$55,018	$9,789
43																					
44	$000	Customer	Dist-Poles	$55,496	$42,111	$8,672	$1,790	$14	$382	$282	$160	$5	$12	$29	$3	$12	$8	$0	$0	$0	$2,015
45	$000	Customer	Dist-Conductor	$27,553	$20,908	$4,305	$889	$7	$190	$140	$79	$3	$6	$14	$1	$6	$4	$0	$0	$0	$1,001
46	$000	Customer	Dist-Transformers	$76,429	$45,720	$12,013	$3,293	$0	$3,414	$2,868	$1,754	$0	$211	$527	$0	$91	$0	$1	$0	$0	$6,535
47	$000	Customer	Dist-Service Drop	$53,903	$40,536	$7,153	$2,859	$0	$989	$763	$836	$0	$88	$424	$0	$252	$0	$3	$0	$0	$0
48	$000	Customer	Meters	$16,147	$12,418	$1,724	$409	$134	$154	$122	$357	$80	$38	$95	$62	$20	$71	$0	$33	$159	$273
49	$000	Customer	Meter Reading	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
50	$000	Customer	Billing & Collections	$16,574	$13,430	$2,119	$437	$3	$170	$125	$71	$2	$7	$19	$2	$27	$18	$0	$8	$2	$132
51	$000	Customer	Uncollectables	$5,914	$5,155	$174	$36	$0	$121	$89	$50	$2	$32	$79	$8	$64	$43	$1	$20	$6	$36
52	$000	Customer	Customer Service / Other	$5,898	$4,955	$642	$132	$1	$49	$36	$21	$1	$3	$8	$1	$4	$3	$0	$1	$0	$41
53	$000	Customer	Total Customer (Commitment & Billing)	$257,913	$185,235	$36,801	$9,846	$160	$5,468	$4,426	$3,326	$93	$397	$1,195	$77	$475	$145	$5	$61	$167	$10,034
54																					
55																					
56			Total Revenue @ Full MC ($000)	$1,162,830	$597,598	$73,906	$49,946	$356	$33,753	$47,019	$57,960	$1,524	$12,105	$60,742	$5,927	$32,928	$30,904	$2,062	$50,264	$73,367	$32,469

5 Year MC

PacifiCorp
Oregon Marginal Cost Study
5 Year Marginal Costs
December 2023 Dollars

					(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)
					Residential	General Service - Schedule 23			General Service - Schedule 28				General Service - Schedule 30			Large Power Service - Schedule 48					Irrg - Sch 41
	Calculation					0-15 kW	15+ kW	Primary	0-50 kW	51-100 kW	100 + kW	Primary	0-300 kW	300+ kW	Primary	1 - 4 MW	1 - 4 MW	> 4 MW	> 4 MW	Trn	
Line	Component	Class	Units Description / Function	Total	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)
1	Units	Demand	Peak MW @ Input-System		1,152	92	100	0	73	108	138	4	30	148	15	75	70	5	125	186	38
2	Units	Energy	Annual MWh @ Input		6,082,593	588,687	635,298	3,533	472,029	718,357	934,868	25,303	206,473	1,070,906	104,635	547,595	531,645	41,798	1,024,837	1,599,365	284,558
3	Units	Customer	Average		535,059	69,806	14,408	115	4,819	3,562	2,012	69	213	531	53	92	61	1	28	8	4,356
4	Units	Customer	Annual		535,059	69,806	14,408	115	4,819	3,562	2,012	69	213	531	53	92	61	1	28	8	7,997
5																					
6																					
7	$/Unit	Demand	Generation ($/System Peak kW)		$93.50	$93.50	$93.50	93.50	$93.50	93.50	$93.50	$93.50	$93.50	$93.50	$93.50	$93.50	$93.50	$93.50	$93.50	$93.50	$93.50
8	$/Unit	Energy	Generation Energy @ Input ($/kWh)		$0.03284	$0.03284	$0.03284	$0.03284	$0.03284	$0.03284	$0.03284	$0.03284	$0.03284	$0.03284	$0.03284	$0.03284	$0.03284	$0.03284	$0.03284	$0.03284	$0.03284
9	$/Unit	Customer	Dist-Service Drop ($/Customer)		$75.76	$102.46	$198.46	$0.00	$205.20	$214.31	$415.31	$0.00	$415.15	$799.21	$0.00	$2,733.92	$0.00	$2,733.92	$0.00	$0.00	$0.00
10	$/Unit	Customer	Meters ($/Customer)		$23.21	$24.69	$28.37	$1,164.18	$31.92	$34.16	$177.40	$1,164.18	$177.96	$178.19	$1,164.18	$215.74	$1,164.18	$215.74	$1,164.18	$19,889.86	$34.18
11	$/Unit	Customer	Meter Reading ($/Customer)		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
12	$/Unit	Customer	Billing & Collections ($/Customer)		$25.10	$30.35	$30.35	$30.35	$35.21	$35.21	$35.21	$35.21	$35.21	$35.21	$35.21	$290.78	$290.78	$290.78	$290.78	$290.78	$30.33
13	$/Unit	Customer	Uncollectables ($/Customer)		$9.64	$2.49	$2.49	$2.49	$25.02	$25.02	$25.02	$25.02	$148.58	$148.58	$148.58	$696.73	$696.73	$696.73	$696.73	$696.73	$8.29
14	$/Unit	Customer	Customer Service / Other ($/Customer)		$9.26	$9.19	$9.19	$9.19	$10.20	$10.20	$10.20	$10.20	$14.74	$14.74	$14.74	$44.26	$44.26	$44.26	$44.26	$44.26	$9.40
15																					
16																					
17	($000)	Demand	Total Demand	$220,497	$107,745	$8,573	$9,353	$44	$6,809	$10,097	$12,885	$345	$2,790	$13,880	$1,428	$6,992	$6,506	$475	$11,681	$17,372	$3,524
18	($000)	Energy	Total Energy	$488,412	$199,752	$19,332	$20,863	$116	$15,501	$23,591	$30,701	$831	$6,781	$35,169	$3,436	$17,983	$17,459	$1,373	$33,656	$52,523	$9,345
19	($000)	Customer	Total Customer (Billing)	$98,436	$76,495	$11,810	$3,874	$139	$1,482	$1,136	$1,334	$85	$169	$624	$72	$366	$134	$4	$61	$167	$483
20			Total Revenue @ Full MC ($000)	$807,346	$383,992	$39,716	$34,090	$299	$23,792	$34,824	$44,920	$1,261	$9,739	$49,673	$4,937	$25,341	$24,099	$1,852	$45,398	$70,063	$13,352

1 Year MC

PacifiCorp
Oregon Marginal Cost Study
1 Year Marginal Costs
December 2023 Dollars

					(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)
					Residential	General Service - Schedule 23			General Service - Schedule 28				General Service - Schedule 30			Large Power Service - Schedule 48					Irrg - Sch 41
	Calculation					0-15 kW	15+ kW	Primary	0-50 kW	51-100 kW	100 + kW	Primary	0-300 kW	300+ kW	Primary	1 - 4 MW	1 - 4 MW	> 4 MW	> 4 MW	Trn	
Line	Component	Class	Units Description / Function	Total	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)
1	Units	Energy	Annual MWh @ Input		6,082,593	588,687	635,298	3,533	472,029	718,357	934,868	25,303	206,473	1,070,906	104,635	547,595	531,645	41,798	1,024,837	1,599,365	284,558
2	Units	Customer	Average		535,059	69,806	14,408	115	4,819	3,562	2,012	69	213	531	53	92	61	1	28	8	4,356
3	Units	Customer	Annual		535,059	69,806	14,408	115	4,819	3,562	2,012	69	213	531	53	92	61	1	28	8	7,997
4																					
5																					
6	$/Unit	Energy	Generation Energy @ Input ($/kWh)		$0.03196	$0.03196	$0.03196	$0.03196	$0.03196	$0.03196	$0.03196	$0.03196	$0.03196	$0.03196	$0.03196	$0.03196	$0.03196	$0.03196	$0.03196	$0.03196	$0.03196
7	$/Unit	Customer	Dist-Service Drop ($/Customer)		75.759615	$102.46	$198.46	$0.00	$205.20	$214.31	$415.31	$0.00	$415.15	$799.21	$0.00	$2,733.92	$0.00	$2,733.92	$0.00	$0.00	$0.00
8	$/Unit	Customer	Meters ($/Customer)		$23.21	$24.69	$28.37	$1,164.18	$31.92	$34.16	$177.40	$1,164.18	$177.96	$178.19	$1,164.18	$215.74	$1,164.18	$215.74	$1,164.18	$19,889.86	$34.18
9	$/Unit	Customer	Meter Reading ($/Customer)		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
10	$/Unit	Customer	Billing & Collections ($/Customer)		$25.10	$30.35	$30.35	$30.35	$35.21	$35.21	$35.21	$35.21	$35.21	$35.21	$35.21	$290.78	$290.78	$290.78	$290.78	$290.78	$30.33
11	$/Unit	Customer	Uncollectables ($/Customer)		$9.64	$2.49	$2.49	$2.49	$25.02	$25.02	$25.02	$25.02	$148.58	$148.58	$148.58	$696.73	$696.73	$696.73	$696.73	$696.73	$8.29
12	$/Unit	Customer	Customer Service / Other ($/Customer)		$9.26	$9.19	$9.19	$9.19	$10.20	$10.20	$10.20	$10.20	$14.74	$14.74	$14.74	$44.26	$44.26	$44.26	$44.26	$44.26	$9.40
13																					
14																					
15	($000)	Energy	Total Energy	$475,384	$194,424	$18,817	$20,307	$113	$15,088	$22,962	$29,882	$809	$6,600	$34,230	$3,345	$17,503	$16,993	$1,336	$32,758	$51,122	$9,096
16	($000)	Customer	Total Customer (Billing)	$98,436	$76,495	$11,810	$3,874	$139	$1,482	$1,136	$1,334	$85	$169	$624	$72	$366	$134	$4	$61	$167	$483
17			Total Revenue @ Full MC ($000)	$573,820	$270,919	$30,627	$24,180	$252	$16,570	$24,098	$31,216	$894	$6,768	$34,855	$3,417	$17,870	$17,127	$1,340	$32,819	$51,289	$9,578

Energy

PacifiCorp
Oregon Marginal Cost Study
Marginal Generation Energy Costs
Nominal Mills / kWh

	(A)	(B) =(A)/12	(C)	(D) =(C)/12	(E) =(D)-(B)	(F)	(G)	(H)	(I)	(J) =(G)+(I)	(K)	(L)	(M)	(N) =(F)+(J)+(M)	(O)	(P) =(N)*(O)
Calendar Year (12 Mo Ended Dec)	SCCT Fixed Costs ($/kW-yr)	SCCT Fixed Costs ($/kW-mo)	CCCT Fixed Costs ($/kW-yr)	CCCT Fixed Costs ($/kW-mo)	Capitalized Energy Cost ($/kW-mo)	Capitalized Energy Cost 70.5% CF ($/MWh)	Purchase Cost ($/MWh)	Updated Gas Price ($/MMBtu)	CCCT Energy Costs 6,790 Btu/kWh ($/MWh)	Variable Avoided Energy Cost ($/MWh)	REC Price ($/REC)	Oregon RPS %	Cost of RPS Compliance ($/MWh)	Total Avoided Energy Cost ($/MWh)	Present Value Factors @ 7.21%	Present Value of Energy (Mills/kWh)
2023	93.53	7.79	171.00	14.25	6.46	12.54	0.00	2.86	19.42	19.42	0.00	20%	0.00	31.96	1.0000	31.96
2024	95.66	7.97	174.89	14.57	6.60	12.83	0.00	2.88	19.56	19.56	0.00	20%	0.00	32.38	0.9327	30.21
2025	97.84	8.15	178.86	14.91	6.75	13.12	0.00	3.16	21.46	21.46	0.00	20%	0.00	34.58	0.8700	30.08
2026	100.07	8.34	182.91	15.24	6.90	13.41	0.00	3.33	22.61	22.61	0.00	20%	0.00	36.02	0.8115	29.23
2027	102.36	8.53	187.11	15.59	7.06	13.72	0.00	3.49	23.70	23.70	0.00	27%	0.00	37.42	0.7569	28.32
2028	104.70	8.73	191.40	15.95	7.23	14.04	0.00	3.71	25.19	25.19	0.00	27%	0.00	39.23	0.7060	27.70
2029	107.09	8.92	195.77	16.31	7.39	14.36	0.00	4.04	27.43	27.43	0.00	27%	0.00	41.79	0.6585	27.52
2030	109.53	9.13	200.23	16.69	7.56	14.69	0.00	4.19	28.45	28.45	0.00	27%	0.00	43.14	0.6142	26.49
2031	112.03	9.34	204.79	17.07	7.73	15.02	0.00	4.33	29.40	29.40	0.00	27%	0.00	44.42	0.5729	25.45
2032	114.58	9.55	209.45	17.45	7.91	15.36	0.00	4.38	29.74	29.74	0.00	35%	0.00	45.10	0.5344	24.10
2033	117.19	9.77	214.20	17.85	8.08	15.71	0.00	4.58	31.10	31.10	0.00	35%	0.00	46.81	0.4985	23.33
2034	119.86	9.99	219.05	18.25	8.27	16.06	0.00	4.61	31.30	31.30	0.00	35%	0.00	47.36	0.4650	22.02
2035	122.60	10.22	224.06	18.67	8.46	16.43	0.00	4.63	31.44	31.44	0.00	35%	0.00	47.87	0.4337	20.76
2036	125.39	10.45	229.19	19.10	8.65	16.81	0.00	4.70	31.91	31.91	0.00	35%	0.00	48.72	0.4045	19.71
2037	128.25	10.69	234.43	19.54	8.85	17.19	0.00	4.83	32.80	32.80	0.00	45%	0.00	49.99	0.3773	18.86
2038	131.17	10.93	239.76	19.98	9.05	17.58	0.00	4.93	33.47	33.47	0.00	45%	0.00	51.06	0.3519	17.97
2039	134.17	11.18	245.21	20.43	9.25	17.98	0.00	5.19	35.24	35.24	0.00	45%	0.00	53.22	0.3282	17.47
2040	137.23	11.44	250.77	20.90	9.46	18.38	0.00	5.43	36.87	36.87	0.00	45%	0.00	55.25	0.3061	16.91
2041	140.36	11.70	256.52	21.38	9.68	18.81	0.00	5.55	37.71	37.71	0.00	45%	0.00	56.52	0.2855	16.14
2042	143.56	11.96	262.38	21.87	9.90	19.24	0.00	5.68	38.57	38.57	0.00	50%	0.00	57.81	0.2663	15.40

	Mills/kWh
2023 (1 Year)	31.96
2023 - 2027 (5 Year, Short Run)	
Sum of PV Costs @ 7.21%	149.81
Annual Cost of Energy @ 21.92%	32.84
2023 - 2032 (10 Year, Medium Run)	
Sum of PV Costs @ 7.21%	281.07
Annual Cost of Energy @ 12.24%	34.40
2023 - 2042 (20 Year, Long Run)	
Sum of PV Costs @ 7.21%	469.63
Annual Cost of Energy @ 7.52%	35.32

Capacity

PacifiCorp
Oregon Marginal Cost Study
Marginal Capacity Costs
Based on Avoided Capacity Costs

	(A)	(B)	(C) (A) x (B)	(D) (A) / 0.705 / 8,760	(E) (B) * (D)
Calendar Year (12 Mo Ended Dec)	Projected Capacity $/kW	Present Value Factors @ 7.21%	PV of Capacity $/kW	Capacity Mills/kWh	PV of Capacity Mills/kWh
2023	$93.53	1.0000	93.53	15.14	15.14
2024	$95.66	0.9327	89.22	15.49	14.45
2025	$97.84	0.8700	85.12	15.84	13.78
2026	$100.07	0.8115	81.21	16.20	13.15
2027	$102.36	0.7569	77.48	16.57	12.54
2028	$104.70	0.7060	73.92	16.95	11.97
2029	$107.09	0.6585	70.52	17.34	11.42
2030	$109.53	0.6142	67.27	17.74	10.90
2031	$112.03	0.5729	64.18	18.14	10.39
2032	$114.58	0.5344	61.23	18.55	9.91
2033	$117.19	0.4985	58.42	18.98	9.46
2034	$119.86	0.4650	55.73	19.41	9.03
2035	$122.60	0.4337	53.17	19.85	8.61
2036	$125.39	0.4045	50.72	20.30	8.21
2037	$128.25	0.3773	48.39	20.77	7.84
2038	$131.17	0.3519	46.16	21.24	7.47
2039	$134.17	0.3282	44.03	21.73	7.13
2040	$137.23	0.3061	42.01	22.22	6.80
2041	$140.36	0.2855	40.07	22.73	6.49
2042	$143.56	0.2663	38.23	23.25	6.19

	$/kW	Mills/kWh
2023 (1 Year)	93.53	15.14
2023 - 2027 (5 Year, Short Run)		
Sum of PV Costs @ 7.21%	426.56	69.06
Annual Cost of Capacity @ 21.92%	93.50	15.14
2023 - 2032 (10 Year, Medium Run)		
Sum of PV Costs @ 7.21%	763.68	123.65
Annual Cost of Capacity @ 12.24%	93.47	15.13
2023 - 2042 (20 Year, Long Run)		
Sum of PV Costs @ 7.21%	1,240.61	200.88
Annual Cost of Capacity @ 7.52%	93.29	15.11

Avoided Costs

PacifiCorp
Filed Marginal Generation Costs

	12 Months Ended December			12 Months Ended December		
Calendar Year	Avoided Simple Cycle CT Fixed Costs ($/kW-yr)	Avoided Combined Cycle CT Fixed Costs ($/kW-yr)	Gas Price ($/MMBtu)	Avoided Firm Capacity Costs ($/kW-yr)	Combined Cycle CT Fixed Cost ($/kW-yr)	Gas Price ($/MMBtu)
2023	93.53	171.00	2.86	93.53	171.00	2.86
2024	95.66	174.89	2.88	95.66	174.89	2.88
2025	97.84	178.86	3.16	97.84	178.86	3.16
2026	100.07	182.91	3.33	100.07	182.91	3.33
2027	102.36	187.11	3.49	102.36	187.11	3.49
2028	104.70	191.40	3.71	104.70	191.40	3.71
2029	107.09	195.77	4.04	107.09	195.77	4.04
2030	109.53	200.23	4.19	109.53	200.23	4.19
2031	112.03	204.79	4.33	112.03	204.79	4.33
2032	114.58	209.45	4.38	114.58	209.45	4.38
2033	117.19	214.20	4.58	117.19	214.20	4.58
2034	119.86	219.05	4.61	119.86	219.05	4.61
2035	122.60	224.06	4.63	122.60	224.06	4.63
2036	125.39	229.19	4.70	125.39	229.19	4.70
2037	128.25	234.43	4.83	128.25	234.43	4.83
2038	131.17	239.76	4.93	131.17	239.76	4.93
2039	134.17	245.21	5.19	134.17	245.21	5.19
2040	137.23	250.77	5.43	137.23	250.77	5.43
2041	140.36	256.52	5.55	140.36	256.52	5.55
2042	143.56	262.38	5.68	143.56	262.38	5.68

CCCT Capacity Factor	70.5%
CCCT Heat Rate (Btu/kWh)	6,790

Fiscal Year:
Previous Year * 75%+Current Year * 25%
Calendar Year:
(Previous Year * 0%)+(Current Year * 100%)
Previous Yr = 0%
Current Yr = 100%

Transm1

PacifiCorp
Oregon Marginal Cost Study
Marginal Transmission Investment and O&M Expenses
2023 Dollars

Line	Description	Calculation	Total	Demand Related	Energy Related
1	2022 Forecast Growth Related Investments ($000)		$44,326	$44,326	$0
2	2023 Forecast Growth Related Investments ($000)		$46,643	$46,643	$0
3	2024 Forecast Growth Related Investments ($000)		$19,155	$19,155	$0
4	2025 Forecast Growth Related Investments ($000)		$33,140	$33,140	$0
5	2026 Forecast Growth Related Investments ($000)		$15,438	$15,438	$0
6					
7	2022 to 2026 Forecast Growth Related Investments ($000)		$158,702	$158,702	$0
8					
9	Capacity Addition MW from 2022-2026		2,879		
10					
11	Marginal Investment ($/KW)	7 / 9	$55.13	$55.13	$0.00
12					
13	Annualized Investment ($/KW)	11 x 6.16%	$3.40	$3.40	$0.00
14	Admin. & General Factor ($/KW)	11 x 0.60%	$0.33	$0.33	$0.00
15	Annual O&M Expenses ($/KW)	11 x 1.176%	$0.65	$0.65	$0.00
16					
17	Annualized Marginal Cost ($/KW)	13 + 14 + 15	$4.38	$4.38	$0.00
18					
19	Marginal Cost of Energy-Related Transmission ($/KWh)	17 / 8760 hrs / 77.45% LF			$0.00000

Transm2

PacifiCorp
Oregon Marginal Cost Study
2022-2026 Forecasted Transmission
December 2023 Dollars (000s)

Line	Description	Calculation	Forecast 2022	2023	2024	2025	2026
1	Bulk Power Lines (grid)		$0	$0	$0	$0	$0
2	Escalation Factor		1.060	1.060	1.060	1.060	1.060
3	Adjusted Bulk Power Lines (grid)	1 x 2	$0	$0	$0	$0	$0
4							
5	Growth Related Major Projects (local)		$41,799	$43,984	$18,063	$31,251	$14,558
6	Escalation Factor		1.0605	1.0605	1.0605	1.0605	1.0605
7	Adjusted Growth Related Major Projects (local)	5 x 6	$44,326	$46,643	$19,155	$33,140	$15,438
8							
9	Total Growth Related Investments - Demand	3 x 29.96% + 7	$44,326	$46,643	$19,155	$33,140	$15,438
10	Total Growth Related Investments - Energy	3 x 70.04%	$0	$0	$0	$0	$0
11	Total Marginal Transmission Investment	3 + 7	$44,326	$46,643	$19,155	$33,140	$15,438

Footnotes:

Line 1 & 5 Bulk power line & growth related projects data provided in 2021 dollars for each year

Line 9 Demand Portion of Transmission = PV of Long Run Capacity Costs / PV of Total Long Run Costs = 200.88 / (200.88+469.63) = 29.96%

Line 10 Energy Portion of Transmission = PV of Long Run Energy Costs / PV of Total Long Run Costs = 469.63 / (200.88+469.63) = 70.04%

Index 2021	Index 2023	Escalation Factor 2021 - 2023
1.0406	1.1035	1.0605

Tran OM

PacifiCorp
Transmission O & M Expenses
(Dollars in 000's)

			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K) =AVERAGE of (A) thru (J)
Line	Description	Calculation	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	
1	Transmission O&M Exp.		204,716	206,484	198,670	211,984	215,664	203,261	204,806	206,506	218,367	210,892	
2	Wheeling		138,235	142,125	137,182	151,336	148,425	130,789	134,473	135,022	145,825	141,188	
3	Net Transmission O&M	1-2	66,481	64,359	61,488	60,648	67,239	72,472	70,333	71,484	72,541	69,703	
4	Transmission Plant		4,500,418	4,724,914	5,231,106	5,387,871	5,910,756	6,051,720	6,222,286	6,353,045	6,478,620	7,630,241	
5	Tran. O&M Loading	3/4	1.477%	1.362%	1.175%	1.126%	1.138%	1.198%	1.130%	1.125%	1.120%	0.914%	1.176%

Source:
PacifiCorp FERC Form 1
(1) page 321, line 112
(2) page 321, line 96
(4) page 206-07, line 58

TranLF

PacifiCorp
System Load Factor

Line No.	Month	Total Monthly Energy	Associated Losses		MW
	(A)	(B)	(C)	(D)	(E)
				(B)-(C)	
1	January	5,521,779	357,238	5,164,541	8,327
2	February	5,031,397	372,019	4,659,378	8,221
3	March	5,200,628	473,753	4,726,875	7,658
4	April	4,483,384	80,680	4,402,704	6,924
5	May	4,781,604	321,598	4,460,006	8,750
6	June	5,111,972	470,864	4,641,108	9,451
7	July	5,880,577	313,386	5,567,191	10,476
8	August	6,044,999	402,100	5,642,899	10,546
9	September	5,023,885	274,292	4,749,593	9,618
10	October	5,304,644	732,752	4,571,892	7,776
11	November	5,467,552	673,488	4,794,064	7,885
12	December	5,879,969	509,753	5,370,216	8,274
13		63,732,390	4,981,923	58,750,467	
14					
15				Average Monthly MW	8,659
16				Load Factor	77.45%

Source: FERC Form 1, December 31, 2020
Page 401b

DistSub1

PacifiCorp
Oregon Marginal Cost Study
Distribution Substation Costs / kW
2023 Dollars

Line	Description	Calculation	Value
1	Incremental Substation Cost ($/kVA)		$325.57
2	Power Factor		0.95
3	Substation Utilization Factor		53.11%
4	Incremental Substation Cost ($/kW)	1/2*3	$182.00
5			
6	Annual Distribution Carrying Charge		6.97%
7			
8	Substation Marginal Cost ($/kW)	4*6	$12.69

DistSub2

PacifiCorp
Marginal Cost Study
Substation Investment

(A)	(B)	(C)	(D)	(E)	(F) =(E)/(D)
In Service Year	Substation Capacity Project	State	Capacity Increase (MVA)	Installed Cost (000)	Installed Cost/MVA (000)
2022	Conser Road	OR	30.0	$11,054	$368.48
2022	Flint	WA	30.0	$20,711	$690.36
2022	Jefferson	OR	7.5	$1,943	$259.02
2022	Shevlin Park	OR	25.0	$4,446	$177.85
2022	Fraley	OR	0.5	$429	$857.53
2023	Dorris	OR	5.0	$1,461	$292.15
2023	Ahtanum	WA	25.0	$10,213	$408.52
2024	Mill City	OR	25.0	$3,667	$146.69
2024	Tieton	WA	25.0	$3,021	$120.85
2025	Empire	OR	25.0	$4,692	$187.66
2025	Fort Jones	CA	7.0	$1,441	$205.86
2025	Banfield	OR	25.0	$8,241	$329.65
2026	Glendale	OR	12.5	$2,795	$223.59
2026	Wake Robin	OR	30.0	$9,545	$318.18
		Western States Total	272.5	$83,659	$307.01

2021 Incremental Substation Cost ($/KVA) $307.01

Index		Escalation Factor
2021	2023	2021 - 2023
1.0406	1.1035	1.0605

2023 Incremental Substation Cost ($/KVA) $325.57

PC 1

PacifiCorp
Oregon Marginal Cost Study
Hypothetical Circuit Study Results
Annual Demand and Commitment Costs
December 2023 Dollars

			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
Line	Load Class		Demand				Commitment			
			Investment \$ / kW[1]		Annual \$ / kW[1]		Investment \$ / Customer		Annual \$ / Customer	
			Poles	Conductor	Poles	Conductor	Poles	Conductor	Poles	Conductor
					(A) x 6.97%	(B) x 6.97%			(E) x 6.97%	(F) x 6.97%
1	Res - Schedule 4	(sec)	$169.36	$260.30	$11.80	$18.14	$778.54	$386.55	$54.26	$26.94
2										
3	GS - Schedule 23									
4	0-15 kW	(sec)	$258.19	$345.16	$18.00	$24.06	$1,228.79	$610.10	$85.65	$42.52
5	15+ kW	(sec)	$258.19	$345.16	$18.00	$24.06	$1,228.79	$610.10	$85.65	$42.52
6	Primary	(pri)	$258.19	$345.16	$18.00	$24.06	$1,228.79	$610.10	$85.65	$42.52
7										
8	GS - Schedule 28									
9	0-50 kW	(sec)	$171.22	$260.40	$11.93	$18.15	$784.18	$389.35	$54.66	$27.14
10	51-100 kW	(sec)	$171.22	$260.40	$11.93	$18.15	$784.18	$389.35	$54.66	$27.14
11	100 + kW	(sec)	$171.22	$260.40	$11.93	$18.15	$784.18	$389.35	$54.66	$27.14
12	Primary	(pri)	$171.22	$260.40	$11.93	$18.15	$784.18	$389.35	$54.66	$27.14
13										
14	GS - Schedule 30									
15	0-300 kW	(sec)	$123.91	$214.65	$8.64	$14.96	$543.14	$269.67	$37.86	$18.80
16	300+ kW	(sec)	$123.91	$214.65	$8.64	$14.96	$543.14	$269.67	$37.86	$18.80
17	Primary	(pri)	$123.91	$214.65	$8.64	$14.96	$543.14	$269.67	$37.86	$18.80
18										
19	LPS - Schedule 48									
20	1 - 4 MW	(sec)	$264.47	$344.11	$18.43	$23.98	$1,244.53	$617.91	$86.74	$43.07
21	1 - 4 MW	(pri)	$264.47	$344.11	$18.43	$23.98	$1,244.53	$617.91	$86.74	$43.07
22	> 4 MW	(sec)	$8.45	$16.43	$0.59	$1.15	$0.00	$0.00	$0.00	$0.00
23	> 4 MW	(pri)	$9.46	$18.39	$0.66	$1.28	$0.00	$0.00	$0.00	$0.00
24										
25	Irrigation - Schedule 41	(sec)	$500.45	$592.31	$34.88	$41.28	$2,492.46	$1,237.52	$173.72	$86.26

Footnote:
[1] $ / kW are in terms of Distribution kW.

PC 2

PacifiCorp
Oregon Marginal Cost Study
Calculation of Escalation Factors
Poles and Conductor
Three Phase Costs as Demand

			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
Line	Load Class		Demand		Commitment		2023 Demand		2023 Commitment	
			Poles	Conductor	Poles	Conductor	Poles (D) x 1.0605	Conductor (C) x 1.0605	Poles (B) x 1.0605	Conductor (A) x 1.0605
1	Res - Schedule 4	(sec)	$159.69	$245.45	$734.13	$364.50	$169.36	$260.30	$778.54	$386.55
2										
3	GS - Schedule 23									
4	0-15 kW	(sec)	$243.46	$325.47	$1,158.69	$575.29	$258.19	$345.16	$1,228.79	$610.10
5	15+ kW	(sec)	$243.46	$325.47	$1,158.69	$575.29	$258.19	$345.16	$1,228.79	$610.10
6	Primary	(pri)	$243.46	$325.47	$1,158.69	$575.29	$258.19	$345.16	$1,228.79	$610.10
7										
8	GS - Schedule 28									
9	0-50 kW	(sec)	$161.46	$245.54	$739.44	$367.14	$171.22	$260.40	$784.18	$389.35
10	51-100 kW	(sec)	$161.46	$245.54	$739.44	$367.14	$171.22	$260.40	$784.18	$389.35
11	100 + kW	(sec)	$161.46	$245.54	$739.44	$367.14	$171.22	$260.40	$784.18	$389.35
12	Primary	(pri)	$161.46	$245.54	$739.44	$367.14	$171.22	$260.40	$784.18	$389.35
13										
14	GS - Schedule 30									
15	0-300 kW	(sec)	$116.84	$202.41	$512.16	$254.29	$123.91	$214.65	$543.14	$269.67
16	300+ kW	(sec)	$116.84	$202.41	$512.16	$254.29	$123.91	$214.65	$543.14	$269.67
17	Primary	(pri)	$116.84	$202.41	$512.16	$254.29	$123.91	$214.65	$543.14	$269.67
18										
19	LPS - Schedule 48									
20	1 - 4 MW	(sec)	$249.38	$324.48	$1,173.53	$582.66	$264.47	$344.11	$1,244.53	$617.91
21	1 - 4 MW	(pri)	$249.38	$324.48	$1,173.53	$582.66	$264.47	$344.11	$1,244.53	$617.91
22	> 4 MW	(sec)	$7.97	$15.49	$0.00	$0.00	$8.45	$16.43	$0.00	$0.00
23	> 4 MW	(pri)	$8.92	$17.34	$0.00	$0.00	$9.46	$18.39	$0.00	$0.00
24										
25	Irrigation - Schedule 41	(sec)	$471.90	$558.52	$2,350.27	$1,166.92	$500.45	$592.31	$2,492.46	$1,237.52

Index		Escalation Factor
2021	2023	2021 - 2023
1.0406	1.1035	1.0605

Footnote:
Pole and conductor costs from Distribution Circuit Model.

PC 3

PacifiCorp
Oregon Marginal Cost Study
Circuit Distribution Model
Inputs & Calculations

Line		(A)	(B)	(C)	(D)	(E)	(F)
1			Number	Average	Distribution	Average	Percent
2		Annual	of	MWh per	Peak	kW per	Single
3		MWh	Customers	Customer	MW	customer	Phase
4	Class			(A) / (B)		(D)/(B) * 1,000	
5	Res - Schedule 4 (sec)	5,755,783	519,723	11.07	1,266	2.43	100.00%
6	GS - Schedule 23 - 0-15 kW (sec)	567,191	70,227	8.08	84	1.19	80.83%
7	GS - Schedule 23 - 15+ kW (sec)	612,100	14,495	42.23	93	6.44	54.35%
8	GS - Schedule 23 - Primary (pri)	3,443	116	29.75	0	2.85	-
9	GS - Schedule 28 - 0-50 kW (sec)	442,735	4,736	93.48	67	14.08	28.88%
10	GS - Schedule 28 - 51-100 kW (sec)	673,777	3,501	192.48	98	28.02	12.69%
11	GS - Schedule 28 - 100 + kW (sec)	876,851	1,977	443.48	125	63.35	1.56%
12	GS - Schedule 28 - Primary (pri)	24,061	68	355.22	3	44.27	-
13	GS - Schedule 30 - 0-300 kW (sec)	186,365	217	859.44	28	127.91	0.47%
14	GS - Schedule 30 - 300+ kW (sec)	966,612	539	1,792.03	137	253.22	-
15	GS - Schedule 30 - Primary (pri)	95,500	53	1,789.23	13	251.41	-
16	Irrigation - Sch 41	237,458	6,572	36.13	62	9.38	15.50%
17	LPS - Schedule 48 - 1 - 4 MW (sec)	503,599	93	5,441.21	70	761.13	-
18	LPS - Schedule 48 - 1 - 4 MW (pri)	510,192	61	8,328.53	66	1,080.41	-
19	LPS - Schedule 48 - > 4 MW (sec)	38,440	1	38,017.58	5	4,763.92	-
20	LPS - Schedule 48 - > 4 MW (pri)	983,483	28	34,895.90	120	4,256.39	-
21	Total	12,477,589	622,407		2,237		
22							
23							

Line									
24		Customer Distribution on the Hypothetical Circuit Branch							
25		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
26					Hypothetical Circuit Branch				Branch
27	Class	1	2	3	4	5	6	7	Total
28	Res - Schedule 4 (sec)	0.38%	0.38%	0.38%	1.83%	1.83%	1.83%	93.37%	100.00%
29	GS - Schedule 23 - 0-15 kW (sec)	0.73%	0.73%	0.73%	2.67%	2.67%	2.67%	89.80%	100.00%
30	GS - Schedule 23 - 15+ kW (sec)	0.73%	0.73%	0.73%	2.67%	2.67%	2.67%	89.80%	100.00%
31	GS - Schedule 23 - Primary (pri)	0.73%	0.73%	0.73%	2.67%	2.67%	2.67%	89.80%	100.00%
32	GS - Schedule 28 - 0-50 kW (sec)	0.45%	0.45%	0.45%	1.53%	1.53%	1.53%	94.08%	100.00%
33	GS - Schedule 28 - 51-100 kW (sec)	0.45%	0.45%	0.45%	1.53%	1.53%	1.53%	94.08%	100.00%
34	GS - Schedule 28 - 100 + kW (sec)	0.45%	0.45%	0.45%	1.53%	1.53%	1.53%	94.08%	100.00%
35	GS - Schedule 28 - Primary (pri)	0.45%	0.45%	0.45%	1.53%	1.53%	1.53%	94.08%	100.00%
36	GS - Schedule 30 - 0-300 kW (sec)	0.28%	0.28%	0.28%	0.98%	0.98%	0.98%	96.23%	100.00%
37	GS - Schedule 30 - 300+ kW (sec)	0.28%	0.28%	0.28%	0.98%	0.98%	0.98%	96.23%	100.00%
38	GS - Schedule 30 - Primary (pri)	0.28%	0.28%	0.28%	0.98%	0.98%	0.98%	96.23%	100.00%
39	Irrigation - Sch 41	1.10%	1.10%	1.10%	7.97%	7.97%	7.97%	72.78%	100.00%
40	LPS - Schedule 48 - 1 - 4 MW (sec)	1.03%	1.03%	1.03%	1.37%	1.37%	1.37%	92.82%	100.00%
41	LPS - Schedule 48 - 1 - 4 MW (pri)	1.03%	1.03%	1.03%	1.37%	1.37%	1.37%	92.82%	100.00%
42	LPS - Schedule 48 - > 4 MW (sec)			Large Customers are on dedicated circuits and are not included here					
43	LPS - Schedule 48 - > 4 MW (pri)			Large Customers are on dedicated circuits and are not included here					
44									
45									

Line		
46	System property records & engineering information	
47	Number of pole feet in Oregon	74,711,073
48	Number of pole miles in Oregon	14,150
49	Number of trench feet in Oregon	28,496,127
50	Number of trench miles in Oregon	5,397
51	Total miles in Oregon	19,547
52	Number of circuits in Oregon	530
53	Number of poles in Oregon	377,374
54	Poles per mile	26.67
55	Customers per mile	31.84
56	MWh per customer	20.05
57	MWh per circuit	23,543
58	Branches per circuit	7
59	Miles per circuit	36.88
60	Miles per branch	5.27
61	Single Phase Miles per Branch[1]	1.84

[1]A 12 KV circuit 12 miles long has approx. 3 miles of single phase, which is approx. 25 percent of circuit distance, so applying 25% to the Miles per Circuit and dividing this amount by the 5 outer branches gives the Single Phase Miles per Branch.

PC 4

PacifiCorp
Oregon Circuit Model Study
Customer Distribution on the Hypothetical Circuit Branch

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
		Hypothetical Circuit Branch							Branch
Line	Class	1	2	3	4	5	6	7	Total
1	Res - Schedule 4 (sec)	0.38%	0.38%	0.38%	1.83%	1.83%	1.83%	93.37%	100.00%
2	GS - Schedule 23 - 0-15 kW (sec)	0.73%	0.73%	0.73%	2.67%	2.67%	2.67%	89.80%	100.00%
3	GS - Schedule 23 - 15+ kW (sec)	0.73%	0.73%	0.73%	2.67%	2.67%	2.67%	89.80%	100.00%
4	GS - Schedule 23 - Primary (pri)	0.73%	0.73%	0.73%	2.67%	2.67%	2.67%	89.80%	100.00%
5	GS - Schedule 28 - 0-50 kW (sec)	0.45%	0.45%	0.45%	1.53%	1.53%	1.53%	94.08%	100.00%
6	GS - Schedule 28 - 51-100 kW (sec)	0.45%	0.45%	0.45%	1.53%	1.53%	1.53%	94.08%	100.00%
7	GS - Schedule 28 - 100 + kW (sec)	0.45%	0.45%	0.45%	1.53%	1.53%	1.53%	94.08%	100.00%
8	GS - Schedule 28 - Primary (pri)	0.45%	0.45%	0.45%	1.53%	1.53%	1.53%	94.08%	100.00%
9	GS - Schedule 30 - 0-300 kW (sec)	0.28%	0.28%	0.28%	0.98%	0.98%	0.98%	96.23%	100.00%
10	GS - Schedule 30 - 300+ kW (sec)	0.28%	0.28%	0.28%	0.98%	0.98%	0.98%	96.23%	100.00%
11	GS - Schedule 30 - Primary (pri)	0.28%	0.28%	0.28%	0.98%	0.98%	0.98%	96.23%	100.00%
12	Irrigation - Sch 41	1.10%	1.10%	1.10%	7.97%	7.97%	7.97%	72.78%	100.00%
13	LPS - Schedule 48 - 1 - 4 MW (sec)	1.03%	1.03%	1.03%	1.37%	1.37%	1.37%	92.82%	100.00%
14	LPS - Schedule 48 - 1 - 4 MW (pri)	1.03%	1.03%	1.03%	1.37%	1.37%	1.37%	92.82%	100.00%
15	LPS - Schedule 48 - > 4 MW (sec)	-	-	-	-	-	-	-	-
16	LPS - Schedule 48 - > 4 MW (pri)	-	-	-	-	-	-	-	-

Except where customers own their own transformers.

PC 5

PacifiCorp
Oregon Circuit Model Study
Average Customers by Hypothetical Circuit Branch

Line		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
1				Hypothetical Circuit Branch					
2	Class	1	2	3	4	5	6	7	Total
3	Res - Schedule 4 (sec)	3.68	3.68	3.68	17.98	17.98	17.98	915.63	980.61
4	GS - Schedule 23 - 0-15 kW (sec)	0.97	0.97	0.97	3.54	3.54	3.54	118.99	132.50
5	GS - Schedule 23 - 15+ kW (sec)	0.20	0.20	0.20	0.73	0.73	0.73	24.56	27.35
6	GS - Schedule 23 - Primary (pri)	0.00	0.00	0.00	0.01	0.01	0.01	0.20	0.22
7	GS - Schedule 28 - 0-50 kW (sec)	0.04	0.04	0.04	0.14	0.14	0.14	8.41	8.94
8	GS - Schedule 28 - 51-100 kW (sec)	0.03	0.03	0.03	0.10	0.10	0.10	6.21	6.60
9	GS - Schedule 28 - 100 + kW (sec)	0.02	0.02	0.02	0.06	0.06	0.06	3.51	3.73
10	GS - Schedule 28 - Primary (pri)	0.00	0.00	0.00	0.00	0.00	0.00	0.12	0.13
11	GS - Schedule 30 - 0-300 kW (sec)	0.00	0.00	0.00	0.00	0.00	0.00	0.39	0.41
12	GS - Schedule 30 - 300+ kW (sec)	0.00	0.00	0.00	0.01	0.01	0.01	0.98	1.02
13	GS - Schedule 30 - Primary (pri)	0.00	0.00	0.00	0.00	0.00	0.00	0.10	0.10
14	Irrigation - Sch 41	0.14	0.14	0.14	0.99	0.99	0.99	9.02	12.40
15	LPS - Schedule 48 - 1 - 4 MW (sec)	0.00	0.00	0.00	0.00	0.00	0.00	0.16	0.17
16	LPS - Schedule 48 - 1 - 4 MW (pri)	0.00	0.00	0.00	0.00	0.00	0.00	0.11	0.12
17	LPS - Schedule 48 - > 4 MW (sec)	-	-	-	-	-	-	-	-
18	LPS - Schedule 48 - > 4 MW (pri)	-	-	-	-	-	-	-	-
19	Total	5.08	5.08	5.08	23.55	23.55	23.55	1,088.39	1,174.30
20									
21	Source - 'Circuit Distribution Model Inputs & Calculations' (PC 3)								
22	Source - 'Customer Distribution on the Hypothetical Circuit Branch' (PC 4)								
23	Customers multiplied by Customer Distribution on the Hypothetical Circuit Branch divided by circuits in the state.								
24	For Example 3.68 is 519,723 Residential Customers X .376% customers on Branch 1 divided by 530 circuits.								
25									
26	Percent of Customers								
27	Res - Schedule 4 (sec)	72.45%	72.45%	72.45%	76.33%	76.33%	76.33%	84.13%	83.51%
28	GS - Schedule 23 - 0-15 kW (sec)	19.05%	19.05%	19.05%	15.01%	15.01%	15.01%	10.93%	11.28%
29	GS - Schedule 23 - 15+ kW (sec)	3.93%	3.93%	3.93%	3.10%	3.10%	3.10%	2.26%	2.33%
30	GS - Schedule 23 - Primary (pri)	0.03%	0.03%	0.03%	0.02%	0.02%	0.02%	0.02%	0.02%
31	GS - Schedule 28 - 0-50 kW (sec)	0.79%	0.79%	0.79%	0.58%	0.58%	0.58%	0.77%	0.76%
32	GS - Schedule 28 - 51-100 kW (sec)	0.58%	0.58%	0.58%	0.43%	0.43%	0.43%	0.57%	0.56%
33	GS - Schedule 28 - 100 + kW (sec)	0.33%	0.33%	0.33%	0.24%	0.24%	0.24%	0.32%	0.32%
34	GS - Schedule 28 - Primary (pri)	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
35	GS - Schedule 30 - 0-300 kW (sec)	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.04%	0.03%
36	GS - Schedule 30 - 300+ kW (sec)	0.06%	0.06%	0.06%	0.04%	0.04%	0.04%	0.09%	0.09%
37	GS - Schedule 30 - Primary (pri)	0.01%	0.01%	0.01%	0.00%	0.00%	0.00%	0.01%	0.01%
38	Irrigation - Sch 41	2.68%	2.68%	2.68%	4.20%	4.20%	4.20%	0.83%	1.06%
39	LPS - Schedule 48 - 1 - 4 MW (sec)	0.04%	0.04%	0.04%	0.01%	0.01%	0.01%	0.01%	0.01%
40	LPS - Schedule 48 - 1 - 4 MW (pri)	0.02%	0.02%	0.02%	0.01%	0.01%	0.01%	0.01%	0.01%
41	LPS - Schedule 48 - > 4 MW (sec)	-	-	-	-	-	-	-	-
42	LPS - Schedule 48 - > 4 MW (pri)	-	-	-	-	-	-	-	-
43	Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
44									
45	Sum of Branch Customers								
46	1,2,3,6	5.08	5.08	5.08			23.55		38.80
47	1,2,3,4,5,6,7	5.08	5.08	5.08	23.55	23.55	23.55	1,088.39	1,174.30
48									
49	1,2,3,6	13.1%	13.1%	13.1%			60.7%		100.0%
50	1,2,3,4,5,6,7	0.4%	0.4%	0.4%	2.0%	2.0%	2.0%	92.7%	100.0%

PC 6

PacifiCorp
Oregon Circuit Model Study
Circuit kW Load by Branch

Line		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
1				Hypothetical Circuit Branch					
2	Class	1	2	3	4	5	6	7	Total
3	Res - Schedule 4 (sec)	8.97	8.97	8.97	43.77	43.77	43.77	2,229.56	2,387.77
4	GS - Schedule 23 - 0-15 kW (sec)	1.15	1.15	1.15	4.21	4.21	4.21	141.78	157.89
5	GS - Schedule 23 - 15+ kW (sec)	1.29	1.29	1.29	4.70	4.70	4.70	158.14	176.10
6	GS - Schedule 23 - Primary (pri)	0.00	0.00	0.00	0.02	0.02	0.02	0.56	0.62
7	GS - Schedule 28 - 0-50 kW (sec)	0.56	0.56	0.56	1.92	1.92	1.92	118.39	125.85
8	GS - Schedule 28 - 51-100 kW (sec)	0.83	0.83	0.83	2.82	2.82	2.82	174.08	185.04
9	GS - Schedule 28 - 100 + kW (sec)	1.06	1.06	1.06	3.61	3.61	3.61	222.32	236.32
10	GS - Schedule 28 - Primary (pri)	0.03	0.03	0.03	0.09	0.09	0.09	5.32	5.66
11	GS - Schedule 30 - 0-300 kW (sec)	0.15	0.15	0.15	0.51	0.51	0.51	50.36	52.34
12	GS - Schedule 30 - 300+ kW (sec)	0.72	0.72	0.72	2.52	2.52	2.52	248.00	257.71
13	GS - Schedule 30 - Primary (pri)	0.07	0.07	0.07	0.25	0.25	0.25	24.37	25.32
14	Irrigation - Sch 41	1.28	1.28	1.28	9.28	9.28	9.28	84.66	116.32
15	LPS - Schedule 48 - 1 - 4 MW (sec)	1.36	1.36	1.36	1.82	1.82	1.82	123.37	132.91
16	LPS - Schedule 48 - 1 - 4 MW (pri)	1.28	1.28	1.28	1.71	1.71	1.71	115.91	124.88
17	LPS - Schedule 48 - > 4 MW (sec)	-	-	-	-	-	-	-	-
18	LPS - Schedule 48 - > 4 MW (pri)	-	-	-	-	-	-	-	-
19	Total	18.75	18.75	18.75	77.21	77.21	77.21	3,696.84	3,984.72
20									
21	Source - 'Circuit Distribution Model Inputs & Calculations' (PC 3)								
22	Source - 'Average Customers by Hypothetical Circuit Branch' (PC 5)								
23	Customers multiplied by circuit kW per customer.								
24	For Example 9.0 is 3.68 Residential Customers multiplied by 2.43 average Dist. kW per Customer.								
25									
26	Percent of Branch Load								
27	Res - Schedule 4 (sec)	47.84%	47.84%	47.84%	56.69%	56.69%	56.69%	60.31%	59.92%
28	GS - Schedule 23 - 0-15 kW (sec)	6.16%	6.16%	6.16%	5.46%	5.46%	5.46%	3.84%	3.96%
29	GS - Schedule 23 - 15+ kW (sec)	6.87%	6.87%	6.87%	6.09%	6.09%	6.09%	4.28%	4.42%
30	GS - Schedule 23 - Primary (pri)	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%
31	GS - Schedule 28 - 0-50 kW (sec)	3.00%	3.00%	3.00%	2.49%	2.49%	2.49%	3.20%	3.16%
32	GS - Schedule 28 - 51-100 kW (sec)	4.42%	4.42%	4.42%	3.66%	3.66%	3.66%	4.71%	4.64%
33	GS - Schedule 28 - 100 + kW (sec)	5.64%	5.64%	5.64%	4.67%	4.67%	4.67%	6.01%	5.93%
34	GS - Schedule 28 - Primary (pri)	0.14%	0.14%	0.14%	0.11%	0.11%	0.11%	0.14%	0.14%
35	GS - Schedule 30 - 0-300 kW (sec)	0.78%	0.78%	0.78%	0.66%	0.66%	0.66%	1.36%	1.31%
36	GS - Schedule 30 - 300+ kW (sec)	3.83%	3.83%	3.83%	3.26%	3.26%	3.26%	6.71%	6.47%
37	GS - Schedule 30 - Primary (pri)	0.38%	0.38%	0.38%	0.32%	0.32%	0.32%	0.66%	0.64%
38	Irrigation - Sch 41	6.83%	6.83%	6.83%	12.01%	12.01%	12.01%	2.29%	2.92%
39	LPS - Schedule 48 - 1 - 4 MW (sec)	7.27%	7.27%	7.27%	2.35%	2.35%	2.35%	3.34%	3.34%
40	LPS - Schedule 48 - 1 - 4 MW (pri)	6.83%	6.83%	6.83%	2.21%	2.21%	2.21%	3.14%	3.13%
41	LPS - Schedule 48 - > 4 MW (sec)	-	-	-	-	-	-	-	-
42	LPS - Schedule 48 - > 4 MW (pri)	-	-	-	-	-	-	-	-
43	Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
44									
45	Sum of Branch Loads								
46	1,2,3,6	18.75	18.75	18.75			77.21		133.45
47	1,2,3,4,5,6,7	18.75	18.75	18.75	77.21	77.21	77.21	3,696.84	3,984.72
48									
49	1,2,3,6	14.05%	14.05%	14.05%			57.86%		100.00%
50	1,2,3,4,5,6,7	0.47%	0.47%	0.47%	1.94%	1.94%	1.94%	92.78%	100.00%

PC 7

PacifiCorp
Oregon Circuit Model Study
System-wide Pole and Conductor Costs

Adjusted Oregon Line Costs per Mile

	State Specific Account 364 Pole Statistics				Adjustment
	Poles	Pole Feet	Pole Miles	Poles / Mile	Factor
California	55,482	12,544,659	2,376	23.35	0.884
Idaho	97,406	21,318,575	4,038	24.12	0.913
Oregon	377,374	74,711,073	14,150	26.67	1.009
Utah	332,602	61,493,319	11,646	28.56	1.081
Washington	99,980	16,626,029	3,149	31.75	1.202
Wyoming	157,847	37,272,116	7,059	22.36	0.846
Total	1,120,691	223,965,771	42,418	26.42	1.000

	Account 364 Pole Cost per Mile			Account 365	Total Line
	Pole Cost	Adjustment	Adjusted	Conductor	Construction
Wire Size	per Mile	Factor	Pole Cost	Cost per Mile	Cost
1 Phase - 1/0 ACSR	$25,517	1.009	$25,758	$12,789	$38,547
3 Phase - 1/0 ACSR	$48,426	1.009	$48,883	$28,548	$77,431
3 Phase - 447 AAC & 4\0 AAC	$54,011	1.009	$54,521	$62,952	$117,473
3 Phase -795 AAC & 477 AAC	$56,143	1.009	$56,673	$110,173	$166,846

	Costs for Branches 1,2,3,4,5		
	1 Phase - 1/0 ACSR	3 Phase - 1/0 ACSR	Total
Poles	$47,499	$167,408	$214,907
Conductors	$23,583	$97,767	$121,350
Total	$71,082	$265,175	$336,257

	Costs for Branch 6	Cost for Branch 7
	3 Phase - 447 AAC & 4\0 AAC	3 Phase -795 AAC & 477 AAC
Poles	$287,255	$298,594
Conductors	$331,674	$580,467
Total	$618,929	$879,060

Miles per Branch 5.27
Single Phase Miles Per Branch 1.84
Three Phase Miles Per Branch 3.42

Commitment and Demand Costs Per Branch

	Poles			Conductor		
	Total Cost	Commitment	Demand	Total Cost	Commitment	Demand
Branches 1,2,3,4,5						
1 Phase - 1/0 ACSR	$47,499	$47,499	$0	$23,583	$23,583	$0
3 Phase - 1/0 ACSR	$167,408	$88,212	$79,196	$97,767	$43,798	$53,969
Total Branches 1,2,3,4,5	$214,907	$135,711	$79,196	$121,350	$67,381	$53,969
Branch 6						
3 Phase - 447 AAC & 4\0 AAC	$287,255	$135,711	$151,544	$331,674	$67,381	$264,293
Branch 7						
3 Phase -795 AAC & 477 AAC	$298,594	$135,711	$162,883	$580,467	$67,381	$513,086
Total All Branches	$1,660,384	$949,976	$710,408	$1,518,892	$471,668	$1,047,223

Branch pole and conductor commitment costs equals single or three Phase Miles Per Branch Multiplied by 1 Phase - 1/0 ACSR Cost

PC 8

PacifiCorp
Oregon Circuit Model Study
Calculation of Hypothetical Circuit Model Branch Cost

		(A)	(B)	(C)	(D)	(E)	(F)
		Total Cost		Commitment Cost		Demand Cost	
	Conductors Type	Poles	Conductor	Poles	Conductor	Poles	Conductor
Branch 1							
	1 Phase - 1/0 ACSR	$ 47,499	$ 23,583	$ 47,499	$ 23,583		
	3 Phase - 1/0 ACSR	$ 167,408	$ 97,767	$ 88,212	$ 43,798	$ 79,196	$ 53,969
	Total segment	$ 214,907	$ 121,350	$ 135,711	$ 67,381	$ 79,196	$ 53,969
Branch 2							
	1 Phase - 1/0 ACSR	$ 47,499	$ 23,583	$ 47,499	$ 23,583		
	3 Phase - 1/0 ACSR	$ 167,408	$ 97,767	$ 88,212	$ 43,798	$ 79,196	$ 53,969
	Total Segments	$ 214,907	$ 121,350	$ 135,711	$ 67,381	$ 79,196	$ 53,969
Branch 3							
	1 Phase - 1/0 ACSR	$ 47,499	$ 23,583	$ 47,499	$ 23,583		
	3 Phase - 1/0 ACSR	$ 167,408	$ 97,767	$ 88,212	$ 43,798	$ 79,196	$ 53,969
	Total Segments	$ 214,907	$ 121,350	$ 135,711	$ 67,381	$ 79,196	$ 53,969
Branch 4							
	1 Phase - 1/0 ACSR	$ 47,499	$ 23,583	$ 47,499	$ 23,583		
	3 Phase - 1/0 ACSR	$ 167,408	$ 97,767	$ 88,212	$ 43,798	$ 79,196	$ 53,969
	Total Segments	$ 214,907	$ 121,350	$ 135,711	$ 67,381	$ 79,196	$ 53,969
Branch 5							
	1 Phase - 1/0 ACSR	$ 47,499	$ 23,583	$ 47,499	$ 23,583		
	3 Phase - 1/0 ACSR	$ 167,408	$ 97,767	$ 88,212	$ 43,798	$ 79,196	$ 53,969
	Total Segments	$ 214,907	$ 121,350	$ 135,711	$ 67,381	$ 79,196	$ 53,969
Branch 6							
	3 Phase - 447 AAC & 4\0 AAC	$ 287,255	$ 331,674	$ 135,711	$ 67,381	$ 151,544	$ 264,293
	Total Segments	$ 287,255	$ 331,674	$ 135,711	$ 67,381	$ 151,544	$ 264,293
Branch 7							
	3 Phase -795 AAC & 477 AAC	$ 298,594	$ 580,467	$ 135,711	$ 67,381	$ 162,883	$ 513,086
	Total segment	$ 298,594	$ 580,467	$ 135,711	$ 67,381	$ 162,883	$ 513,086
	$3,179,275	$1,660,384	$1,518,892	$949,976	$471,668	$710,408	$1,047,223

Source - 'System-wide Pole and Conductor Costs' (PC 7)

PC 9

PacifiCorp
Oregon Circuit Model Study
Pole Demand Calculations

Line		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
					Hypothetical Circuit Branch					
		1	2	3	4	5	6	7		
1	% customer	14.05%	14.05%	14.05%			57.86%		100.00%	
2	Branch 6 Cost	$ 21,288	$ 21,288	$ 21,288			$ 87,679		$ 151,544	$ / kW
3	% customer	0.47%	0.47%	0.47%	1.94%	1.94%	1.94%	92.78%	100.00%	
4	Branch 7 Cost	$ 766	$ 766	$ 766	$ 3,156	$ 3,156	$ 3,156	$ 151,115	$ 162,883	
5	Branch Commitment Cost	$ 79,196	$ 79,196	$ 79,196	$ 79,196	$ 79,196				Average
6	Total	$ 101,251	$ 101,251	$ 101,251	$ 82,352	$ 82,352	$ 90,835	$ 151,115	$ 710,408	$ 178.28
7										
8									Total	
9									Demand	$ Per
10	Class Cost per Branch	1	2	3	4	5	6	7	Cost	kW
11	Res - Schedule 4 (sec)	$ 48,440	$ 48,440	$ 48,440	$ 46,683	$ 46,683	$ 51,491	$ 91,137	$ 381,314	$ 159.69
12	GS - Schedule 23 - 0-15 kW (sec)	$ 6,233	$ 6,233	$ 6,233	$ 4,494	$ 4,494	$ 4,957	$ 5,796	$ 38,439	$ 243.46
13	GS - Schedule 23 - 15+ kW (sec)	$ 6,952	$ 6,952	$ 6,952	$ 5,012	$ 5,012	$ 5,529	$ 6,464	$ 42,874	$ 243.46
14	GS - Schedule 23 - Primary (pri)	$ 25	$ 25	$ 25	$ 18	$ 18	$ 20	$ 23	$ 151	$ 243.46
15	GS - Schedule 28 - 0-50 kW (sec)	$ 3,041	$ 3,041	$ 3,041	$ 2,049	$ 2,049	$ 2,260	$ 4,840	$ 20,319	$ 161.46
16	GS - Schedule 28 - 51-100 kW (sec)	$ 4,471	$ 4,471	$ 4,471	$ 3,012	$ 3,012	$ 3,323	$ 7,116	$ 29,876	$ 161.46
17	GS - Schedule 28 - 100 + kW (sec)	$ 5,710	$ 5,710	$ 5,710	$ 3,847	$ 3,847	$ 4,243	$ 9,088	$ 38,155	$ 161.46
18	GS - Schedule 28 - Primary (pri)	$ 137	$ 137	$ 137	$ 92	$ 92	$ 102	$ 218	$ 913	$ 161.46
19	GS - Schedule 30 - 0-300 kW (sec)	$ 788	$ 788	$ 788	$ 545	$ 545	$ 601	$ 2,059	$ 6,115	$ 116.84
20	GS - Schedule 30 - 300+ kW (sec)	$ 3,882	$ 3,882	$ 3,882	$ 2,683	$ 2,683	$ 2,960	$ 10,138	$ 30,112	$ 116.84
21	GS - Schedule 30 - Primary (pri)	$ 381	$ 381	$ 381	$ 264	$ 264	$ 291	$ 996	$ 2,958	$ 116.84
22	Irrigation - Sch 41	$ 6,911	$ 6,911	$ 6,911	$ 9,893	$ 9,893	$ 10,913	$ 3,461	$ 54,893	$ 471.90
23	LPS - Schedule 48 - 1 - 4 MW (sec)	$ 7,363	$ 7,363	$ 7,363	$ 1,939	$ 1,939	$ 2,138	$ 5,043	$ 33,146	$ 249.38
24	LPS - Schedule 48 - 1 - 4 MW (pri)	$ 6,917	$ 6,917	$ 6,917	$ 1,821	$ 1,821	$ 2,009	$ 4,738	$ 31,142	$ 249.38
25	LPS - Schedule 48 - > 4 MW (sec)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	LPS - Schedule 48 - > 4 MW (pri)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Check Total	$ 101,251	$ 101,251	$ 101,251	$ 82,352	$ 82,352	$ 90,835	$ 151,115	$ 710,408	

Sources: Line 1 & 3 - 'Circuit kW Load by Branch' (PC 6)
Line 2 - 'Calculation of Hypothetical Circuit Model Branch Cost' (PC 8) for $151,544
Line 1 X $151,544
Line 4 - 'Calculation of Hypothetical Circuit Model Branch Cost' (PC 8) for $162,883
Line 3 X $162,883
Line 5 - 'Calculation of Hypothetical Circuit Model Branch Cost' (PC 8)
Line 7 to 18 - Line 6 X Percent of Branch Load 'Circuit kW Load by Branch' (PC 6)

PC 10

PacifiCorp
Oregon Circuit Model Study
Conductor Demand Calculations

Line		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
					Hypothetical Circuit Branch					
		1	2	3	4	5	6	7		
1	% customer	14.05%	14.05%	14.05%			57.86%		100.00%	
2	Branch 6 Cost	$ 37,127	$ 37,127	$ 37,127			$ 152,912		$ 264,293	$ / kW
3	% customer	0.47%	0.47%	0.47%	1.94%	1.94%	1.94%	92.78%	100.00%	
4	Branch 7 Cost	$ 2,414	$ 2,414	$ 2,414	$ 9,942	$ 9,942	$ 9,942	$ 476,017	$ 513,086	
5	Branch Commitment Cost	$ 53,969	$ 53,969	$ 53,969	$ 53,969	$ 53,969				Average
6	Total	$ 93,510	$ 93,510	$ 93,510	$ 63,911	$ 63,911	$ 162,854	$ 476,017	$ 1,047,223	$ 262.81
7										
8									Total	
9									Demand	$ Per
10	Class Cost per Branch	1	2	3	4	5	6	7	Cost	kW
11	Res - Schedule 4 (sec)	$ 44,737	$ 44,737	$ 44,737	$ 36,229	$ 36,229	$ 92,316	$ 287,085	$ 586,070	$ 245.45
12	GS - Schedule 23 - 0-15 kW (sec)	$ 5,756	$ 5,756	$ 5,756	$ 3,488	$ 3,488	$ 8,887	$ 18,256	$ 51,387	$ 325.47
13	GS - Schedule 23 - 15+ kW (sec)	$ 6,421	$ 6,421	$ 6,421	$ 3,890	$ 3,890	$ 9,912	$ 20,363	$ 57,317	$ 325.47
14	GS - Schedule 23 - Primary (pri)	$ 23	$ 23	$ 23	$ 14	$ 14	$ 35	$ 72	$ 202	$ 325.47
15	GS - Schedule 28 - 0-50 kW (sec)	$ 2,808	$ 2,808	$ 2,808	$ 1,590	$ 1,590	$ 4,051	$ 15,245	$ 30,900	$ 245.54
16	GS - Schedule 28 - 51-100 kW (sec)	$ 4,129	$ 4,129	$ 4,129	$ 2,338	$ 2,338	$ 5,957	$ 22,415	$ 45,435	$ 245.54
17	GS - Schedule 28 - 100 + kW (sec)	$ 5,273	$ 5,273	$ 5,273	$ 2,986	$ 2,986	$ 7,608	$ 28,627	$ 58,026	$ 245.54
18	GS - Schedule 28 - Primary (pri)	$ 126	$ 126	$ 126	$ 71	$ 71	$ 182	$ 685	$ 1,389	$ 245.54
19	GS - Schedule 30 - 0-300 kW (sec)	$ 728	$ 728	$ 728	$ 423	$ 423	$ 1,078	$ 6,485	$ 10,593	$ 202.41
20	GS - Schedule 30 - 300+ kW (sec)	$ 3,586	$ 3,586	$ 3,586	$ 2,083	$ 2,083	$ 5,307	$ 31,934	$ 52,162	$ 202.41
21	GS - Schedule 30 - Primary (pri)	$ 352	$ 352	$ 352	$ 205	$ 205	$ 521	$ 3,137	$ 5,125	$ 202.41
22	Irrigation - Sch 41	$ 6,383	$ 6,383	$ 6,383	$ 7,678	$ 7,678	$ 19,565	$ 10,901	$ 64,969	$ 558.52
23	LPS - Schedule 48 - 1 - 4 MW (sec)	$ 6,800	$ 6,800	$ 6,800	$ 1,505	$ 1,505	$ 3,834	$ 15,886	$ 43,128	$ 324.48
24	LPS - Schedule 48 - 1 - 4 MW (pri)	$ 6,388	$ 6,388	$ 6,388	$ 1,414	$ 1,414	$ 3,602	$ 14,925	$ 40,519	$ 324.48
25	LPS - Schedule 48 - > 4 MW (sec)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	LPS - Schedule 48 - > 4 MW (pri)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Check Total	$ 93,510	$ 93,510	$ 93,510	$ 63,911	$ 63,911	$ 162,854	$ 476,017	$ 1,047,223	

PC 11

PacifiCorp
Oregon Circuit Model Study
Pole Commitment Calculations

Line		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
		Hypothetical Circuit Branch								
		1	2	3	4	5	6	7		
1	% customer	13.10%	13.10%	13.10%			60.69%		100.00%	
2	Branch 6 Cost	$ -	$ -	$ -			$ -		$ -	$ Per
3	% customer	0.43%	0.43%	0.43%	2.01%	2.01%	2.01%	92.68%	100.00%	Customer
4	Branch 7 Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
5	Branch Commitment Cost	$ 135,711	$ 135,711	$ 135,711	$ 135,711	$ 135,711	$ 135,711	$ 135,711		Average
6	Total	$ 135,711	$ 135,711	$ 135,711	$ 135,711	$ 135,711	$ 135,711	$ 135,711	$ 949,976	$ 808.97
7										
8									Total	
9									Commitment	$ Per
10	Class Cost per Branch	1	2	3	4	5	6	7	Cost	Customer
11	Res - Schedule 4 (sec)	$ 98,326	$ 98,326	$ 98,326	$ 103,582	$ 103,582	$ 103,582	$ 114,170	$ 719,894	$ 734.13
12	GS - Schedule 23 - 0-15 kW (sec)	$ 25,854	$ 25,854	$ 25,854	$ 20,377	$ 20,377	$ 20,377	$ 14,837	$ 153,530	$ 1,158.69
13	GS - Schedule 23 - 15+ kW (sec)	$ 5,337	$ 5,337	$ 5,337	$ 4,206	$ 4,206	$ 4,206	$ 3,062	$ 31,690	$ 1,158.69
14	GS - Schedule 23 - Primary (pri)	$ 43	$ 43	$ 43	$ 34	$ 34	$ 34	$ 24	$ 253	$ 1,158.69
15	GS - Schedule 28 - 0-50 kW (sec)	$ 1,067	$ 1,067	$ 1,067	$ 786	$ 786	$ 786	$ 1,048	$ 6,608	$ 739.44
16	GS - Schedule 28 - 51-100 kW (sec)	$ 789	$ 789	$ 789	$ 581	$ 581	$ 581	$ 775	$ 4,884	$ 739.44
17	GS - Schedule 28 - 100 + kW (sec)	$ 446	$ 446	$ 446	$ 328	$ 328	$ 328	$ 438	$ 2,759	$ 739.44
18	GS - Schedule 28 - Primary (pri)	$ 15	$ 15	$ 15	$ 11	$ 11	$ 11	$ 15	$ 95	$ 739.44
19	GS - Schedule 30 - 0-300 kW (sec)	$ 30	$ 30	$ 30	$ 23	$ 23	$ 23	$ 49	$ 210	$ 512.16
20	GS - Schedule 30 - 300+ kW (sec)	$ 76	$ 76	$ 76	$ 57	$ 57	$ 57	$ 122	$ 521	$ 512.16
21	GS - Schedule 30 - Primary (pri)	$ 7	$ 7	$ 7	$ 6	$ 6	$ 6	$ 12	$ 52	$ 512.16
22	Irrigation - Sch 41	$ 3,641	$ 3,641	$ 3,641	$ 5,698	$ 5,698	$ 5,698	$ 1,125	$ 29,142	$ 2,350.27
23	LPS - Schedule 48 - 1 - 4 MW (sec)	$ 48	$ 48	$ 48	$ 14	$ 14	$ 14	$ 20	$ 205	$ 1,173.53
24	LPS - Schedule 48 - 1 - 4 MW (pri)	$ 32	$ 32	$ 32	$ 9	$ 9	$ 9	$ 13	$ 136	$ 1,173.53
25	LPS - Schedule 48 - > 4 MW (sec)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	LPS - Schedule 48 - > 4 MW (pri)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Check Total	$ 135,711	$ 135,711	$ 135,711	$ 135,711	$ 135,711	$ 135,711	$ 135,711	$ 949,976	

PC 12

PacifiCorp
Oregon Circuit Model Study
Conductor Commitment Calculations

Line		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
					Hypothetical Circuit Branch					
		1	2	3	4	5	6	7		
1	% customer	13.10%	13.10%	13.10%			60.69%		100.00%	
2	Branch 6 Cost	$ -	$ -	$ -			$ -		$ -	$ Per
3	% customer	0.43%	0.43%	0.43%	2.01%	2.01%	2.01%	92.68%	100.00%	Customer
4	Branch 7 Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
5	Branch Commitment Cost	$ 67,381	$ 67,381	$ 67,381	$ 67,381	$ 67,381	$ 67,381	$ 67,381		Average
6	Total	$ 67,381	$ 67,381	$ 67,381	$ 67,381	$ 67,381	$ 67,381	$ 67,381	$ 471,668	$ 401.66
7										
8									Total	
9									Commitment	$ Per
10	Class Cost per Branch	1	2	3	4	5	6	7	Cost	Customer
11	Res - Schedule 4 (sec)	$ 48,820	$ 48,820	$ 48,820	$ 51,429	$ 51,429	$ 51,429	$ 56,686	$ 357,431	$ 364.50
12	GS - Schedule 23 - 0-15 kW (sec)	$ 12,837	$ 12,837	$ 12,837	$ 10,117	$ 10,117	$ 10,117	$ 7,366	$ 76,228	$ 575.29
13	GS - Schedule 23 - 15+ kW (sec)	$ 2,650	$ 2,650	$ 2,650	$ 2,088	$ 2,088	$ 2,088	$ 1,520	$ 15,734	$ 575.29
14	GS - Schedule 23 - Primary (pri)	$ 21	$ 21	$ 21	$ 17	$ 17	$ 17	$ 12	$ 126	$ 575.29
15	GS - Schedule 28 - 0-50 kW (sec)	$ 530	$ 530	$ 530	$ 390	$ 390	$ 390	$ 520	$ 3,281	$ 367.14
16	GS - Schedule 28 - 51-100 kW (sec)	$ 392	$ 392	$ 392	$ 288	$ 288	$ 288	$ 385	$ 2,425	$ 367.14
17	GS - Schedule 28 - 100 + kW (sec)	$ 221	$ 221	$ 221	$ 163	$ 163	$ 163	$ 217	$ 1,370	$ 367.14
18	GS - Schedule 28 - Primary (pri)	$ 8	$ 8	$ 8	$ 6	$ 6	$ 6	$ 7	$ 47	$ 367.14
19	GS - Schedule 30 - 0-300 kW (sec)	$ 15	$ 15	$ 15	$ 11	$ 11	$ 11	$ 24	$ 104	$ 254.29
20	GS - Schedule 30 - 300+ kW (sec)	$ 38	$ 38	$ 38	$ 28	$ 28	$ 28	$ 61	$ 259	$ 254.29
21	GS - Schedule 30 - Primary (pri)	$ 4	$ 4	$ 4	$ 3	$ 3	$ 3	$ 6	$ 26	$ 254.29
22	Irrigation - Sch 41	$ 1,808	$ 1,808	$ 1,808	$ 2,829	$ 2,829	$ 2,829	$ 559	$ 14,469	$ 1,166.92
23	LPS - Schedule 48 - 1 - 4 MW (sec)	$ 24	$ 24	$ 24	$ 7	$ 7	$ 7	$ 10	$ 102	$ 582.66
24	LPS - Schedule 48 - 1 - 4 MW (pri)	$ 16	$ 16	$ 16	$ 5	$ 5	$ 5	$ 7	$ 67	$ 582.66
25	LPS - Schedule 48 - > 4 MW (sec)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	LPS - Schedule 48 - > 4 MW (pri)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Check Total	$ 67,381	$ 67,381	$ 67,381	$ 67,381	$ 67,381	$ 67,381	$ 67,381	$ 471,668	

PC 13

PacifiCorp
Oregon Circuit Model Study
Dedicated Circuit Trunk Costs
For Large Customers

	Voltage Delivery			
	Large GS + 4 MW (pri)		Large GS + 4 MW (sec)	
	Poles	Conductor	Poles	Conductor
1 Construction Cost Per Mile	$ 56,673	$ 110,173	$ 56,673	$ 110,173
2 Average Trunk Length	0.67 miles		0.67 miles	
3 Total Construction Cost	$ 37,971	$ 73,816	$ 37,971	$ 73,816
4 Customer Peak Demand	4,256 kW		4,764 kW	
5 Demand Cost $/kW	$8.92	$17.34	$7.97	$15.49

Construction Costs for Distribution Line type - 3 Phase -795 AAC & 477 AAC.

Line 1 - 'System-wide Pole and Conductor Costs' (PC 7)
Line 2 - Distribution Engineering Studies
Line 3 - Line 1 multiplied by Line 2
Line 4 - 'Circuit Distribution Model Inputs & Calculations' (PC 3)
Line 5 - Line 3 divided by Line 4

PC 14

PacifiCorp
Oregon Circuit Model Study
Trunk All Demand Costs
Outer Branches Commitment & Demand
Three Phase As Needed

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
								=(C)*(F)	=(D)*(F)
		Commitment $/Customer		Demand $/Dist. kW		Typical circuit		Demand $/circuit	
Line	Class	Poles	Conductor	Poles	Conductor	Customers	kW	Poles	Conductor
1	Res - Schedule 4 (sec)	$ 734.13	$ 364.50	$ 159.69	$ 245.45	980.6	2,387.77	$ 381,314	$ 586,070
2	GS - Schedule 23 - 0-15 kW (sec)	$ 1,158.69	$ 575.29	$ 243.46	$ 325.47	132.5	157.89	$ 38,439	$ 51,387
3	GS - Schedule 23 - 15+ kW (sec)	$ 1,158.69	$ 575.29	$ 243.46	$ 325.47	27.3	176.10	$ 42,874	$ 57,317
4	GS - Schedule 23 - Primary (pri)	$ 1,158.69	$ 575.29	$ 243.46	$ 325.47	0.2	0.62	$ 151	$ 202
5	GS - Schedule 28 - 0-50 kW (sec)	$ 739.44	$ 367.14	$ 161.46	$ 245.54	8.9	125.85	$ 20,319	$ 30,900
6	GS - Schedule 28 - 51-100 kW (sec)	$ 739.44	$ 367.14	$ 161.46	$ 245.54	6.6	185.04	$ 29,876	$ 45,435
7	GS - Schedule 28 - 100 + kW (sec)	$ 739.44	$ 367.14	$ 161.46	$ 245.54	3.7	236.32	$ 38,155	$ 58,026
8	GS - Schedule 28 - Primary (pri)	$ 739.44	$ 367.14	$ 161.46	$ 245.54	0.1	5.66	$ 913	$ 1,389
9	GS - Schedule 30 - 0-300 kW (sec)	$ 512.16	$ 254.29	$ 116.84	$ 202.41	0.4	52.34	$ 6,115	$ 10,593
10	GS - Schedule 30 - 300+ kW (sec)	$ 512.16	$ 254.29	$ 116.84	$ 202.41	1.0	257.71	$ 30,112	$ 52,162
11	GS - Schedule 30 - Primary (pri)	$ 512.16	$ 254.29	$ 116.84	$ 202.41	0.1	25.32	$ 2,958	$ 5,125
12	Irrigation - Sch 41	$ 2,350.27	$ 1,166.92	$ 471.90	$ 558.52	12.4	116.32	$ 54,893	$ 64,969
13	LPS - Schedule 48 - 1 - 4 MW (sec)	$ 1,173.53	$ 582.66	$ 249.38	$ 324.48	0.2	132.91	$ 33,146	$ 43,128
14	LPS - Schedule 48 - 1 - 4 MW (pri)	$ 1,173.53	$ 582.66	$ 249.38	$ 324.48	0.1	124.88	$ 31,142	$ 40,519
15	Total -	$ 808.97	$ 401.66	$ 178.28	$ 262.81	1,174.3	3,984.7	$ 710,408	$ 1,047,223
16									
17	Large GS + 4 MW (sec)	$ -	$ -	$ 7.97	$ 15.49	-	4,763.92	$ 37,971	$ 73,816
18	Large GS + 4 MW (pri)	$ -	$ -	$ 8.92	$ 17.34	-	4,256.39	$ 37,971	$ 73,816
								$ 786,350	$ 1,194,855

	Commitment	Demand	Total
Poles	$ 949,976	$ 786,350	$ 1,736,326
Conductor	$ 471,668	$ 1,194,855	$ 1,666,524
Total	$ 1,421,644	$ 1,981,205	$ 3,402,849

Source : Column (A) - Pole Commitment Calculations' (PC 11)
Column (B) - Conductor Commitment Calculations' (PC 12)
Column (C) - Pole Demand Calculations' (PC 9)
Column (D) - Conductor Demand Calculations' (PC 10)
Column (E) - Average Customers by Hypothetical Circuit Branch' (PC 5)
Column (F) - Circuit kW Load by Branch' (PC 6)

XFMR 1

PacifiCorp
Oregon Marginal Cost Study
Transformer Commitment Costs

Line	Customer Type	(A) Percent of Customers	(B) Dollars / Tran.	(C) Weighted $ / Tran.	(D) # Cust. / Tran.	(E) Transformer $ / Cust.	(F) Average Customers	(G) Tot. Trans. Commitment $
				(A) x (B)		(C) / (D)		(E) x (F)
1	Res - Schedule 4	100.00%	240.75	240.75	4.09	$58.91	535,059	$31,520,326
2								
3	GS - Schedule 23							
4	1 Phase	80.83%	240.75	194.60	2.66	$73.11		
5	3 Phase	19.17%	753.04	144.37	3.17	$45.54		
6	0-15 kW	100.00%				$118.65	69,806	$8,282,213
7								
8	1 Phase	54.35%	240.75	130.85	2.66	$49.16		
9	3 Phase	45.65%	753.04	343.77	3.17	$108.43		
10	15+ kW	100.00%				$157.59	14,408	$2,270,516
11								
12	Primary	100.00%	-	-	-	0	115	$0
13								
14	GS - Schedule 28							
15	1 Phase	28.88%	240.75	69.53	1.23	$56.53		
16	3 Phase	71.12%	753.04	535.57	1.24	$431.91		
17	0-50 kW	100.00%				$488.44	4,819	$2,353,791.13
18								
19	1 Phase	12.69%	240.75	30.55	1.23	$24.84		
20	3 Phase	87.31%	753.04	657.49	1.24	$530.23		
21	51-100 kW	100.00%				$555.07	3,562	$1,977,164
22								
23	1 Phase	1.56%	240.75	3.76	1.23	$3.06		
24	3 Phase	98.44%	753.04	741.27	1.24	$597.80		
25	100 + kW	100.00%				$600.86	2,012	$1,208,921
26								
27	Primary	100.00%	-	-	-	0	69	$0
28								
29	GS - Schedule 30							
30	1 Phase	0.47%	240.75	1.13	1.07	$1.06		
31	3 Phase	99.53%	753.04	749.52	1.10	$681.38		
32	0-300 kW	100.00%				$682.44	213	$145,359
33								
34	1 Phase	0.00%	240.75	-	1.07	$0.00		
35	3 Phase	100.00%	753.04	753.04	1.10	$684.58		
36	300+ kW	100.00%				$684.58	531	$363,513
37								
38	Primary	100.00%	-	-	0.00	0	53	$0
39								
40	LPS - Schedule 48							
41	1 - 4 MW (sec)	100.00%	753.04	753.04	1.10	$684.58	92	$62,982
42	1 - 4 MW (pri)	100.00%	-	-	0.00	$0.00	61	$0
43	> 4 MW (sec)	100.00%	753.04	753.04	1.10	$684.58	1	$685
44	> 4 MW (pri)	100.00%	-	-	0.00	$0.00	28	$0
45	Trans (trn)	100.00%	-	-	0.00	$0.00	8	$0
46								
47	Schedule 41- Irrigation							
48	1 Phase	15.50%	240.75	37.32	1.30	$28.71		
49	3 Phase	84.50%	753.04	636.31	1.19	$534.71		
50	Total	100.00%				$563.42	7,997	$4,505,686

XFMR 2

PacifiCorp
Oregon Marginal Cost Study
Transformer Demand Costs

Line	Customer Type		(A) Weighted $ / kW	(B) Transformer Peak kW	(C) Tot. Trans. Demand $ (A) x (B)
1	Res - Schedule 4	(sec)	$1.02	3,413,133	$3,492,797
2					
3	GS - Schedule 23				
4	0-15 kW	(sec)	$1.02	419,071	$428,852
5	15+ kW	(sec)	$1.02	259,999	$266,068
6	Primary	(pri)	$0.00	0	$0
7					
8	GS - Schedule 28				
9	0-50 kW	(sec)	$1.02	269,617	$275,909
10	51-100 kW	(sec)	$1.02	444,697	$455,076
11	100 + kW	(sec)	$1.02	349,255	$357,407
12	Primary	(pri)	$0.00	0	$0
13					
14	GS - Schedule 30				
15	0-300 kW	(sec)	$1.02	63,411	$64,891
16	300+ kW	(sec)	$1.02	239,143	$244,724
17	Primary	(pri)	$0.00	0	$0
18					
19					
20	LPS - Schedule 48				
21	1 - 4 MW	(sec)	$1.02	119,399	$122,186
22	1 - 4 MW	(pri)	$0.00	0	$0
23	> 4 MW	(sec)	$1.02	8,225	$8,417
24	> 4 MW	(pri)	$0.00	0	$0
25	Trans	(trn)	$0.00	0	$0
26					
27	Irrigation - Schedule 41 (Average)				
28	Secondary	(sec)	$1.02	211,511	$216,448
29					
30	Totals			5,797,461	$5,932,775

XFMR 3

PacifiCorp
Oregon Marginal Cost Study
Calculation of Escalation Factors for Transformers
(Regression weighted by number of transformer banks)

		(A)	(B)	(C)	(D)	(E)
Line	Description	Demand Related	Adjusted for System Power Factor of 0.95	Commitment Related	Indexed to 2023	Annualized $ @ 6.97%
			(A) / 0.95		(B) or (C) x 1.0605	(D) x 6.97%
1	1 Phase $/kW	$13.15	$13.84		$14.68	$1.02
2						
3	3 Phase $/kW	$13.15	$13.84		$14.68	$1.02
4						
5	1 Phase			$3,257.07	$3,454.12	$240.75
6	$/Transformer					
7						
8	3 Phase			$6,930.63		
9	Dummy Variable					
10						
11	3 Phase			$10,187.70	$10,804.06	$753.04
12	$/Transformer					

Index		Escalation Factor
2021	2023	2021 - 2023
1.0406	1.1035	1.0605

Dist OM

PacifiCorp
Oregon Marginal Cost Study
Distribution O&M Expense
Loading Factor as a Percent of Dist. Plant
(Excluding Meters and St Ltg)

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
Line	Description	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
	Distribution O & M Expenses										
1	Total Distribution O & M Expense	66,557,786	67,568,987	68,689,786	70,580,614	69,136,197	61,535,374	61,513,756	61,139,370	68,212,991	83,124,296
2	Less:										
3	585 St Ltg & Signal Systems	63,875	60,545	54,154	61,627	58,974	64,715	39,416	64,984	59,838	74,457
4	586 Meter Expense	3,548,094	3,194,944	2,991,325	3,120,160	2,616,262	1,645,292	1,079,103	883,546	655,758	1,279,281
5	587 Customer Installation Expense	4,633,258	4,311,287	4,352,166	4,244,231	4,157,616	5,227,622	5,089,251	5,107,333	5,763,027	6,702,788
6	596 Main. of St Ltg & Signal Systems	1,251,031	1,084,668	1,057,829	918,033	896,454	953,051	879,053	889,400	890,418	831,495
7	597 Main. of Meters	1,386,968	1,556,466	1,628,742	1,653,908	1,198,881	10,098	59,787	85,408	231,001	235,870
8											
9	Total Adjusted Distribution O & M Expense	55,674,560	57,361,078	58,605,569	60,582,655	60,208,010	53,634,596	54,367,145	54,108,699	60,612,949	74,000,405
10	Line 1 - (Lines 3 through 7)										
11											
12											
13	Distribution Plant										
14	Total Distribution Plant	1,733,406,361	1,780,993,170	1,823,007,262	1,866,641,345	1,916,622,378	1,970,302,647	2,040,304,183	2,128,892,665	2,179,547,153	2,311,229,537
15	Less:										
16	370 Meters	59,771,898	59,665,589	59,706,364	60,110,283	60,993,623	62,541,755	65,791,804	76,927,946	90,849,203	96,302,523
17	373 Street Lighting	21,961,746	22,297,246	22,570,478	22,805,367	23,072,497	23,284,230	23,564,547	23,857,078	24,085,782	24,386,485
18											
19	Adjusted Distribution Plant	1,651,672,717	1,699,030,335	1,740,730,420	1,783,725,695	1,832,556,258	1,884,476,662	1,950,947,833	2,028,107,642	2,064,612,168	2,190,540,529
20	Line 14 - Line 16 - Line 17										
21											
22											
23	O & M Expense Loading Factor										
24	Distribution O & M Loading	3.37%	3.38%	3.37%	3.40%	3.29%	2.85%	2.79%	2.67%	2.94%	3.38%
25	Line 9 / Line 19										
26											
27	Average Distribution O & M Loading	3.14%									
28	Average of Line 24										
29											
30	Distribution Annual Charge	6.97%									
31											
32	Annualized Distribution O & M Loading Factor	$\boxed{45.05\%}$									
33	Line 27 / Line 30										

Footnotes:
Source: FERC Form 1 (State of Oregon) & Results of Operations

PacifiCorp
Oregon Marginal Cost Study
Weighted Average Installed Service Drop Costs
Res - Schedule 4 / GS - Schedule 23 / GS - Schedule 28

Line	Load Class	(A) Customers	(B) % 1 & 3 Phase	(C) Overhead Service Drop Cost	(D) Underground Service Drop Cost	(E) % Overhead	(F) % Underground	(G) Weighted Service Drop Cost	(H) Weighted Service Drop Cost 1 & 3 Phase	(I) Weighted Service Drop Cost 1 Phase	(J) Weighted Service Drop Cost 3 Phase
			(A) / (A,Ttl)						(B) x (E)		
1	Res - Schedule 4	519,723	100.00%					$749	$749	$749	
2	Annualized - Line 1 x 6.97%								$52	$52	
3											
4	GS - Schedule 23										
5	0-15 kW										
6	kW = 0, 1 Phase	4,515	6.43%	$958	$771	61.6%	38.4%	$886	$57	$70	
7	kW = 0, 3 Phase	105	0.15%	$1,176	$1,089	61.6%	38.4%	$1,143	$2		$9
8	kW > 1, 1 Phase	52,248	74.40%	$1,067	$814	61.6%	38.4%	$970	$722	$893	
9	kW > 1, 3 Phase	13,359	19.02%	$1,277	$1,146	61.6%	38.4%	$1,227	$233		$1,217
10	Total 0-15 kW	70,227	100.00%						$1,014	$963	$1,226
11	Annualized - Line 10 x 6.97%								$71	$67	$85
12											
13	15+ kW										
14	1 Phase	7,878	54.35%	$1,920	$1,441	61.6%	38.4%	$1,736	$943	$1,736	
15	3 Phase	6,617	45.65%	$2,313	$2,107	61.6%	38.4%	$2,234	$1,020		$2,234
16	Total 15+ kW	14,495	100.00%						$1,963	$1,736	$2,234
17	Annualized - Line 16 x 6.97%								$137	$121	$156
18											
19	Primary										
20	12.47 KV 4-wire Wye	116	100.00%					$0			
21	Annualized - (Line 20) x 6.97%							$0	$0	$0	$0
22											
23	GS - Schedule 28										
24	0-50 kW										
25	1 Phase	1,368	28.88%	$1,920	$1,441	40.4%	59.6%	$1,634	$472	$1,634	
26	3 Phase	3,369	71.12%	$2,313	$2,107	40.4%	59.6%	$2,190	$1,558		$2,190
27	Total 0-50 kW	4,736	100.00%						$2,030	$1,634	$2,190
28	Annualized - Line 27 x 6.97%								$141	$114	$153
29											
30	51-100 kW										
31	1 Phase	444	12.69%	$1,920	$1,441	40.4%	59.6%	$1,634	$207	$1,634	
32	3 Phase	3,056	87.31%	$2,313	$2,107	40.4%	59.6%	$2,190	$1,912		$2,190
33	Total 51-100 kW	3,501	100.00%						$2,120	$1,634	$2,190
34	Annualized - Line 33 x 6.97%								$148	$114	$153
35											
36	100 + kW										
37	1 Phase	31	1.56%	$3,535	$4,423	40.4%	59.6%	$4,064	$64	$4,064	
38	3 Phase	1,946	98.44%	$4,117	$4,103	40.4%	59.6%	$4,109	$4,044		$4,109
39	Total 100 + kW	1,977	100.00%						$4,108	$4,064	$4,109
40	Annualized - Line 39 x 6.97%								$286	$283	$286
41											
42	Primary										
43	12.47 KV 4-wire Wye	68	100.00%					$0	$0		$0
44	Annualized - (Line 43) x 6.97%								$0	$0	$0

Services 2

PacifiCorp
Oregon Marginal Cost Study
Weighted Average Installed Service Drop Costs
GS - Schedule 30 / LPS - Schedule 48

Line	Load Class	(A) Customers	(B) % 1 & 3 Phase	(C) Overhead Service Drop Cost	(D) Underground Service Drop Cost	(E) % Overhead	(F) % Underground	(G) Weighted Service Drop Cost	(H) Weighted Service Drop Cost 1 & 3 Phase
			(A) / (A,Ttl)						(B) x (E)
1	GS - Schedule 30								
2									
3	0-300 kW								
4	1 Phase	1	0.47%	$3,535	$4,423	18.1%	81.9%	$4,262	$19.93
5	3 Phase	216	99.53%	$4,117	$4,103	18.1%	81.9%	$4,106	$4,086.38
6	Total 0-300 kW	217	100.00%						$4,106.31
7	Annualized - Line 6 x 6.97%								$286.21
8									
9	300+ kW								
10	1 Phase	0	0.00%	$8,937	$7,677	18.1%	81.9%	$7,905	$0.00
11	3 Phase	539	100.00%	$8,937	$7,677	18.1%	81.9%	$7,905	$7,905.20
12	Total 300+ kW	539	100.00%						$7,905.20
13	Annualized - Line 12 x 6.97%								$550.99
14									
15	Primary								
16	12.47 KV 4-wire Wye	53	100.00%					$0	$0.00
17	Annualized - Line 16 x 6.97%								$0.00
18									
19	LPS - Schedule 48								
20	1 - 4 MW (sec)	93	100.00%		$27,042	0.0%	100.0%	$27,042	$27,041.69
21	Annualized - Line 20 x 6.97%								$1,884.81
22									
23	1 - 4 MW (pri)	61	100.00%					$0	$0.00
24	Annualized - Line 23 x 6.97%								$0.00
25									
26	> 4 MW (sec)	1	100.00%		$27,042	0.0%	100.0%	$27,042	$27,041.69
27	Annualized - Line 26 x 6.97%								$1,884.81
28									
29	> 4 MW (pri)	28	100.00%					$0	$0.00
30	Annualized - Line 29 x 6.97%								$0.00
31									
32	Trans (trn)	8	100.00%					$0	$0.00
33	Annualized - Line 32 x 6.97%								$0.00

Services 3

PacifiCorp
Oregon Marginal Cost Study
Summary of Average Installed Costs
Service Drops

		(A)	(B)	(C)	(D)	(E)
Line	Load Class	Service Conductor	Cost	Indexed to 2023	Percent Use	Total Cost per Service
				(B) x 1.0605		
	Residential					
1	OH - small load	#2 Triplex*	$630	$668	30.5%	$203.89
2	OH - all electric	1/0 Triplex	$727	$771	27.1%	$208.78
3	UG - small load	1/0 Triplex	$727	$771	18.9%	$145.55
4	UG - all electric	4/0 Triplex	$766	$812	23.5%	$191.11
5						$749.32
6	0 - 15 kW					
7	kW = 0, 1 Phase	OH - 1/0 Triplex	$903	$958		
8	kW = 0, 1 Phase	UG - 1/0 Triplex	$727	$771		
9	kW = 0, 3 Phase	OH - 1/0 Quadruplex	$1,109	$1,176		
10	kW = 0, 3 Phase	UG - 1/0 Quadruplex	$1,027	$1,089		
11	kW > 1, 1 Phase	OH - 4/0 Triplex	$1,006	$1,067		
12	kW > 1, 1 Phase	UG - 4/0 Triplex	$768	$814		
13	kW > 1, 3 Phase	OH - 4/0 Quadruplex	$1,204	$1,277		
14	kW > 1, 3 Phase	UG - 4/0 Quadruplex	$1,081	$1,146		
15						
16	16 - 100 kW					
17	1 Phase	OH - 2-4/0 Triplex	$1,810	$1,920		
18	1 Phase	UG - 2-4/0 Triplex	$1,359	$1,441		
19	3 Phase	OH - 2-4/0 Quadruplex	$2,181	$2,313		
20	3 Phase	UG - 2-4/0 Quadruplex	$1,987	$2,107		
21						
22	101 - 300 kW					
23	1 Phase	3-500 & 350N	$3,333	$3,535		
24	1 Phase	3- 750 & 500 N	$4,171	$4,423		
25	3 Phase	OH - 3-4/0 Quadruplex	$3,882	$4,117		
26	3 Phase	4-350 Quad	$3,869	$4,103		
27						
28	301 - 1000 kW					
29	3 Phase	3-750 kcmil Quad.	$8,427	$8,937		
30	3 Phase	4-750 kcmil Quad.	$7,239	$7,677		
31						
32	1000 kW and Over					
33	Secondary Voltage	12-1000 kcmil Quad.	$25,499	$27,042		
34	Primary Voltage	---	---	---		---

Index		Escalation Factor
2021	2023	2021 - 2023
1.0406	1.1035	1.0605

		Weighted %
Residential Overhead % =	57.6%	
% of Overhead Which Are Small Load=	53.0%	30.5%
% of Overhead Which Are All Electric=	47.0%	27.1%
Residential Underground % =	42.4%	
% of Underground Which Are Small Load=	44.5%	18.9%
% of Underground Which Are All Electric=	55.5%	23.5%
Total OH & UG		100.0%

Meters 1

PacifiCorp
Oregon Marginal Cost Study
Weighted Average Installed Meter Costs
Res - Schedule 4 / GS - Schedule 23 / GS - Schedule 28

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
			% of Customers				Weighted Metering Cost		
Line	Load Class	Customers	1 & 3 Phase	1 Phase	3 Phase	Metering Cost	1 & 3 Phase	1 Phase	3 Phase
			(A) / (A,Ttl)	(A) / 1Ø	(A) / 3Ø		(B) x (E)	(C) x (E)	(D) x (E)
1	Res - Schedule 4	519,723	100.00%	100.00%		$200	$200.03	$200.03	
2	Annualized - (Line 1) x 6.97%						$13.94	$13.94	
3									
4	GS - Schedule 23								
5	0-15 kW								
6	kW = 0, 1 Phase	4,515	6.43%	7.95%		$190	$12.20	$15.10	
7	kW = 0, 3 Phase	105	0.15%		0.78%	$310	$0.46		$2.41
8	kW > 1, 1 Phase	52,248	74.40%	92.05%		$190	$141.23	$174.73	
9	kW > 1, 3 Phase	13,359	19.02%		99.22%	$310	$58.91		$307.26
10	Total 0-15 kW	70,227	100.00%	100.00%	100.00%		$212.80	$189.83	$309.67
11	Annualized - (Line 10) x 6.97%						$14.83	$13.23	$21.58
12									
13	15+ kW								
14	1 Phase	7,878	54.35%	100.00%		$190	$103.17	$189.83	
15	3 Phase W/O KVAR	3,485	24.05%		52.67%	$310	$74.46		$163.11
16	3 Phase With KVAR	3,132	21.60%		47.33%	$310	$66.90		$146.56
17	Total 15+ kW	14,495	100.00%	100.00%	100.00%		$244.53	$189.83	$309.67
18	Annualized - (Line 17) x 6.97%						$17.04	$13.23	$21.58
19									
20	Primary								
21	12.47 KV 4-wire Wye	116	100.00%		100.00%	$10,032	$10,032.33		$10,032.33
22	Annualized - (Line 21) x 6.97%						$699.25	$0.00	$699.25
23									
24	GS - Schedule 28								
25	0-50 kW								
26	kW = 0, 1 Phase	6	0.12%	0.42%		$190	$0.23	$0.79	
27	kW = 0, 3 Phase	12	0.26%		0.37%	$310	$0.81		$1.14
28	kW > 1, 1 Phase	1,362	28.76%	99.58%		$190	$54.59	$189.04	
29	kW > 1, 3 Phase	3,356	70.86%		99.63%	$310	$219.43		$308.53
30	Total 0-50 kW	4,736	100.00%	100.00%	100.00%		$275.06	$189.83	$309.67
31	Annualized - (Line 30) x 6.97%						$19.17	$13.23	$21.58
32									
33	51-100 kW								
34	1 Phase	444	12.69%	100.00%		$190	$24.09	$189.83	
35	3 Phase W/O KVAR	1,355	38.71%		44.33%	$310	$119.86		$137.28
36	3 Phase With KVAR	1,701	48.60%		55.67%	$310	$150.51		$172.39
37	Total 51-100 kW	3,501	100.00%	100.00%	100.00%		$294.46	$189.83	$309.67
38	Annualized - (Line 37) x 6.97%						$20.52	$13.23	$21.58
39									
40	100 + kW								
41	1 Phase	31	1.56%	100.00%		$1,098	$17.16	$1,097.62	
42	3 Phase W/O KVAR	761	38.51%		39.12%	$1,536	$591.41		$600.80
43	3 Phase With KVAR	1,185	59.92%		60.88%	$1,536	$920.18		$934.80
44	Total 100 + kW	1,977	100.00%	100.00%	100.00%		$1,528.75	$1,097.62	$1,535.60
45	Annualized - (Line 44) x 6.97%						$106.55	$76.50	$107.03
46									
47	Primary								
48	12.47 KV 4-wire Wye	68	100.00%		100.00%	$10,032	$10,032.33		$10,032.33
49	Annualized - (Line 48) x 6.97%						$699.25	$0.00	$699.25

Footnote:
Column A - Customer inputs from Pricing Dept - data based on 12 months ended June 2021.

Meters 2

PacifiCorp
Oregon Marginal Cost Study
Weighted Average Installed Meter Costs
GS - Schedule 30 / LPS - Schedule 48 / Irrigation - Schedule 41 (Annual)

Line	Load Class	(A) Customers	(B) % of Customers 1 & 3 Phase (A) / (A,Ttl)	(C) % of Customers 1 Phase (A) / 1Ø	(D) % of Customers 3 Phase (A) / 3Ø	(E) Metering Cost	(F) Weighted Metering Cost 1 & 3 Phase (B) x (E)	(G) Weighted Metering Cost 1 Phase (C) x (E)	(H) Weighted Metering Cost 3 Phase (D) x (E) (F) x 6.97%
1	GS - Schedule 30								
2	0-300 kW								
3	1 Phase	1	0.47%	100.00%		$1,098	$5.13	$1,097.62	
4	3 Phase W/O KVAR	53	24.42%		24.53%	$1,536	$374.99		$376.75
5	3 Phase With KVAR	163	75.11%		75.47%	$1,536	$1,153.43		$1,158.85
6	Total 0-300 kW	217	100.00%	100.00%	100.00%		$1,533.55	$1,097.62	$1,535.60
7	Annualized - (Line 6) x 6.97%						$106.89	$76.50	$107.03
8									
9	300+ kW								
10	1 Phase	0	0.00%	100.00%		$1,360	$0.00	$1,359.56	
11	3 Phase W/O KVAR	112	20.77%		20.77%	$1,536	$318.99		$318.99
12	3 Phase With KVAR	427	79.23%		79.23%	$1,536	$1,216.62		$1,216.62
13	300+ kW	539	100.00%	100.00%	100.00%		$1,535.61	$1,359.56	$1,535.61
14	Annualized - (Line 13) x 6.97%						$107.03	$94.76	$107.03
15									
16	Primary								
17	12.47 KV 4-wire Wye	53	100.00%		100.00%	$10,032	$10,032.33		$10,032.33
18	Annualized - (Line 17) x 6.97%						$699.25		$699.25
19									
20	LPS - Schedule 48								
21	1 - 4 MW (sec)	93	100.00%		100.00%	$1,859	$1,859.06		$1,859.06
22	Annualized - (Line 21) x 6.97%						$129.58		$129.58
23									
24	1 - 4 MW (pri)	61	100.00%		100.00%	$10,032	$10,032.33		$10,032.33
25	Annualized - (Line 24) x 6.97%						$699.25		$699.25
26									
27	> 4 MW (sec)	1	100.00%		100.00%	$1,859	$1,859.06		$1,859.06
28	Annualized - (Line 27) x 6.97%						$129.58		$129.58
29									
30	> 4 MW (pri)	28	100.00%		100.00%	$10,032	$10,032.33		$10,032.33
31	Annualized - (Line 30) x 6.97%						$699.25		$699.25
32									
33	Trans (trn)	8	100.00%		100.00%	$171,400	$171,400.00		$171,400.00
34	Annualized - (Line 33) x 6.97%						$11,946.58		$11,946.58
35									
36									
37	Irrigation - Schedule 41 (Annual)								
38	0 - 50 kW								
39	kW = 0, 1 Phase	-	0.00%	0.00%		$190	$0.00	$0.00	
40	kW = 0, 3 Phase	-	0.00%		0.00%	$310	$0.00		$0.00
41	kW > 1, 1 Phase	1,017	15.49%	99.90%		$190	$29.40	$189.64	
42	kW > 1, 3 Phase	4,558	69.39%		82.12%	$310	$214.88		$254.30
43									
44	51 - 300 kW								
45	1 Phase	1	0.02%	0.10%		$190	$0.03	$0.19	
46	3 Phase W/O KVAR	124	1.89%		2.23%	$310	$5.85		$6.92
47	3 Phase With KVAR	850	12.94%		15.31%	$310	$40.07		$47.42
48									
49	> 300 kW								
50	1 Phase	-	0.00%	0.00%		$1,360	$0.00	$0.00	
51	3 Phase W/O KVAR	3	0.05%		0.06%	$1,536	$0.76		$0.90
52	3 Phase With KVAR	15	0.23%		0.28%	$1,536	$3.57		$4.23
53	Total Irrigation	6,569	100.00%	100.00%	100.00%		$294.56	$189.83	$313.77
54							$20.53	$13.23	$21.87
55									
56	Primary	3	100.00%		100.00%	$0	$0.00		$0.00
57							$0.00	$0.00	$0.00

Footnote:
Column A - Customer inputs from Pricing Dept - data based on 12 months ended June 2021.

Meters 3

PacifiCorp
Oregon Marginal Cost Study
Incremental Three Phase
Meter and Services Costs

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
		Meters				Service Drops			
Line	Load Class	Single Phase	Three Phase	Difference	Annualized Difference	Single Phase	Three Phase	Difference	Annualized Difference
				(B) - (A)	(C) x 6.97%			(F) - (E)	(G) x 6.97%
1	Residential	$200.03	$309.67	$109.64	$7.64	$749.32	$1,139.22	$389.90	$27.18
2									
3	0-15 kW	$189.83	$309.67	$119.84	$8.35	$969.82	$1,226.69	$256.87	$17.90
4									
5	16-100 kW	$189.83	$309.67	$119.84	$8.35	$1,735.61	$2,233.85	$498.24	$34.73
6									
7	101-1000 kW	$1,359.56	$1,535.60	$176.04	$12.27	$4,064.47	$4,108.64	$44.18	$3.08
8									
9	1 - 4 MW	N.A.	$1,859.06	N.A.	N.A.	N.A.	$27,041.69	N.A.	N.A.

Meters 4

PacifiCorp
Oregon Marginal Cost Study
Summary of Average Installed Costs
Meters

Line	Load Class	(A) Metering Standard	(B) Meter Cost in 2021 Dollars	(C) Indexed to 2023	(D) Percent Use	(E) Total Installed Cost per Meter
	Residential					
1	Small Load	DM221J	$179.00	189.8295	49.39%	93.76611809
2	All Electric	DM221K	$198.00	$209.98	50.61%	$106.26
3					100.00%	$200.03
4						
5	0 - 15 kW					
6	kW = 0, 1 Phase	DM221J	$179.00	$189.83	100.00%	$189.83
7						
8	kW = 0, 3 Phase	DM241D	$292.00	$309.67	100.00%	$309.67
9						
10	kW > 1, 1 Phase	DM221J	$179.00	$189.83	100.00%	$189.83
11						
12	kW > 1, 3 Phase	DM241D	$292.00	$309.67	100.00%	$309.67
13						
14						
15	15 - 100 kW					
16	1 Phase	DM221J	$179.00	$189.83	100.00%	$189.83
17						
18	3 Phase wo / KVAR	DM241D	$292.00	$309.67	100.00%	$309.67
19						
20	3 Phase with KVAR	DM241D	$292.00	$309.67	100.00%	$309.67
21						
22						
23	100 - 300 kW					
24	1 Phase	DM231FBB	$1,035.00	$1,097.62	100.00%	$1,097.62
25						
26	3 Phase wo / KVAR	DM271DEC	$1,448.00	$1,535.60	100.00%	$1,535.60
27						
28	3 Phase with KVAR	DM271DEC	$1,448.00	$1,535.60	100.00%	$1,535.60
29						
30						
31	300-1000 kW					
32	W/O KVAR, 1 Phase	DM231FFE	$1,282.00	$1,359.56	100.00%	$1,359.56
33						
34	W/O KVAR, 3 Phase	DM271DEC	$1,448.00	$1,535.60	100.00%	$1,535.60
35						
36	W/KVAR, 3 Phase	DM271DEC	$1,448.00	$1,535.60	100.00%	$1,535.60
37						
38						
39	1000 kW and over					
40	Secondary Volt	DM271AEG	$1,753.00	$1,859.06	100.00%	$1,859.06
41						
42	Primary Metering					
43	13.8 KV 3-wire	DM101ACBA	$8,022.00	$8,507.33		$8,507.33
44	12.47 KV 4-wire Wye	DM121ACJAD	$9,460.00	$10,032.33		$10,032.33
45	24.9 KV 4-wire Wye	DM121BFIAD	$13,387.00	$14,196.91		$14,196.91
46	35 KV 4-wire Wye	DM131BBAH	$15,302.00	$16,227.77		$16,227.77

Index		Escalation Factor
2021	2023	2021 - 2023
1.0406	1.1035	1.0605

Meters 5

PacifiCorp
Oregon Marginal Cost Study
Distribution Meters Expense
Loading Factor

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
Line	Description	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
	Distribution Meters Expenses										
1	586 Meter Expense	3,548,094	3,194,944	2,991,325	3,120,160	2,616,262	1,645,292	1,079,103	883,546	655,758	1,279,281
2	597 Main. of Meters	1,386,968	1,556,466	1,628,742	1,653,908	1,198,881	10,098	59,787	85,408	231,001	235,870
3											
4	Total Adjusted Distribution Meters Expense	4,935,062	4,751,410	4,620,067	4,774,068	3,815,143	1,655,390	1,138,890	968,955	886,759	1,515,150
5	Line 1 + Line 2										
6											
7											
8											
9	Distribution Meters										
10	370 Meters	59,771,898	59,665,589	59,706,364	60,110,283	60,993,623	62,541,755	65,791,804	76,927,946	90,849,203	96,302,523
11											
12											
13											
14	Meters Expense Loading Factor										
15	Meter O&M Loading	8.26%	7.96%	7.74%	7.94%	6.25%	2.65%	1.73%	1.26%	0.98%	1.57%
16	Line 4 / Line 10										
17											
18	Average Meter O&M Loading	4.63%									
19	Average of Line 15										
20											
21	Distribution Annual Charge	6.97%									
22											
23	Annualized Meter O&M Loading Factor	66.49%									
24	Line 18 / Line 21										

Lgt 1

PacifiCorp
Oregon Marginal Cost Study
Street, Area, and Recreational Lighting
Full Marginal Cost by Schedule

Line	Units Description / Function	Company Owned																	Customer Owned	
		Schedule 51														Schedule 15			Schedule 53	Schedule 54
		Level 1 (0-3,500 LED Equivalent Lumens)	Level 2 (3,501-5,500 LED Equivalent Lumens)	Level 3 (5,501-8,000 LED Equivalent Lumens)	Level 4 (8,001-12,000 LED Equivalent Lumens)	Level 5 (12,001-15,500 LED Equivalent Lumens)	Level 6 (15,501 and Greater LED Equivalent Lumens)	Dec Series Level 2 (3,501-5,500 LED Equivalent Lumens)	Dec Series Level 3 (5,501-8,000 LED Equivalent Lumens)	Cust. Funded Conv. - Level 1 (0-3,500 LED Equivalent Lumens)	Cust. Funded Conv. - Level 2 (3,501-5,500 LED Equivalent Lumens)	Cust. Funded Conv. - Level 3 (5,501-8,000 LED Equivalent Lumens)	Cust. Funded Conv. - Level 4 (8,001-12,000 LED Equivalent Lumens)	Cust. Funded Conv. - Level 5 (12,001-15,500 LED Equivalent Lumens)	Cust. Funded Conv. - Level 6 (15,501 and Greater LED Equivalent Lumens)	Level 1 (0-5,500 LED Equivalent Lumens)	Level 2 (5,501-12,000 LED Equivalent Lumens)	Level 3 (12,001 and Greater LED Equivalent Lumens)		
1	Average Annual Lamps	8,761	13,590	1,505	4,413	1,361	1,139	112	16	321	3,248	1,388	216	312	39	5,694	1,401	348		
2	Avg Lamp kW @ Input	0.042	0.054	0.081	0.093	0.146	0.201	0.054	0.081	0.042	0.054	0.081	0.093	0.146	0.201	0.043	0.108	0.163		
3	Peak kW @ Input-Distribution																		19	27
4	Peak kW @ Input-Transformer																		2,886	5,254
5	Peak kW @ Input-System	47	134	24	98	38	42	1	0	2	32	22	5	9	1	68	31	13	668	309
6																				
7	Annual kWh @ Sales	876,058	2,487,016	445,579	1,822,500	714,481	783,403	20,572	4,637	32,067	594,369	410,971	89,242	163,844	26,660	1,269,706	578,407	239,653	11,451,780	1,141,242
8	Monthly kWh Usg @ Sales per Lamp	8	15	25	34	44	57	15	25	8	15	25	34	44	57	19	34	57		
9	Losses	1.0797	1.0797	1.0797	1.0797	1.0797	1.0797	1.0797	1.0797	1.0797	1.0797	1.0797	1.0797	1.0797	1.0797	1.0797	1.0797	1.0797	1.0797	1.0797
10	Annual kWh @ Input	945,836	2,685,107	481,069	1,967,662	771,390	845,801	22,211	5,007	34,621	641,710	443,705	96,351	176,894	28,783	1,370,838	624,477	258,742	12,363,914	1,232,142
11	Monthly kWh Usg @ Input per Lamp	9	16	27	37	47	62	16	27	9	16	27	37	47	62	20	37	62		
12																				
13																				
14	Gen $/kWh @ Input	$0.03532	$0.03532	$0.03532	$0.03532	$0.03532	$0.03532	$0.03532	$0.03532	$0.03532	$0.03532	$0.03532	$0.03532	$0.03532	$0.03532	$0.03532	$0.03532	$0.03532	$0.03532	$0.03532
15	Transm $/kWh @ Input	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
16																				
17	Generation ($/kW)	$93.29	$93.29000	$93.29000	$93.29000	$93.29000	$93.29000	$93.29000	$93.29000	$93.29000	$93.29000	$93.29000	$93.29000	$93.29000	$93.29000	$93.29000	$93.29000	$93.29000	$93.29000	$93.29000
18																				
19	Transmission ($/kW)	$4.38	$4.38000	$4.38000	$4.38000	$4.38000	$4.38000	$4.38000	$4.38000	$4.38000	$4.38000	$4.38000	$4.38000	$4.38000	$4.38000	$4.38000	$4.38000	$4.38000	$4.38000	$4.38000
20																				
21																				
22	Distribution-Poles ($/kW)	$24.61	$24.61	$24.61	$24.61	$24.61	$24.61	$24.61	$24.61	$24.61	$24.61	$24.61	$24.61	$24.61	$24.61	$24.61	$24.61	$24.61	$24.61	$24.61
23	Index	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605
24	Revised Distribution-Poles, incl. Annualization @ 6.97% ($/kW)	$26.10	$26.10	$26.10	$26.10	$26.10	$26.10	$26.10	$26.10	$26.10	$26.10	$26.10	$26.10	$26.10	$26.10	$26.10	$26.10	$26.10	$26.10	$26.10
25																				
26	Distribution-Conductor ($/kW)	$32.91	$32.91	$32.91	$32.91	$32.91	$32.91	$32.91	$32.91	$32.91	$32.91	$32.91	$32.91	$32.91	$32.91	$32.91	$32.91	$32.91	$32.91	$32.91
27	Index	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605
28	Revised Distribution-Conductor, incl. Annualization @ 6.97% ($/kW)	$34.89	$34.89	$34.89	$34.89	$34.89	$34.89	$34.89	$34.89	$34.89	$34.89	$34.89	$34.89	$34.89	$34.89	$34.89	$34.89	$34.89	$34.89	$34.89
29																				
30	Distribution-Transformer ($/kW)	$8.23	$8.23	$8.23	$8.23	$8.23	$8.23	$8.23	$8.23	$8.23	$8.23	$8.23	$8.23	$8.23	$8.23	$8.23	$8.23	$8.23	$13.84	$13.84
31	Index	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605
32	Revised Distribution-Transformer, incl. Annualization @ 6.97% ($/kW)	$8.73	$8.73	$8.73	$8.73	$8.73	$8.73	$8.73	$8.73	$8.73	$8.73	$8.73	$8.73	$8.73	$8.73	$8.73	$8.73	$8.73	$1.48	$1.48
33																				
34	Distribution-Lighting - Installations	$969.94	$1,035.60	$1,040.07	$1,049.54	$1,107.58	$1,347.79	$2,960.67	$2,960.67							$847.54	$941.52	$1,092.52		
35	Index	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605							1.0605	1.0605	1.0605		
36	Revised Distribution-Lighting Installations, incl. Annualization @ 6.97%	$71.69	$76.55	$76.88	$77.58	$81.87	$99.62	$218.83	$218.83							$62.64	$69.59	$80.75		
37																				
38	Distribution-Lighting O&M	$77.83	$81.12	$81.34	$81.81	$83.81	$100.76	$59.04	$59.04	$77.83	$81.12	$81.34	$81.81	$83.81	$100.76	$40.93	$44.69	$51.45		
39	Index	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605	1.0605		
40	Revised Distribution-Lighting O&M	$82.54	$86.02	$86.26	$86.76	$88.87	$106.85	$62.61	$62.61	$82.54	$86.02	$86.26	$86.76	$88.87	$106.85	$43.41	$47.39	$54.56		
41																				
42	Monthly Cost Per Company-Owned Lamp																			
43	Generation Energy	$0.32	$0.58	$0.94	$1.31	$1.67	$2.19	$0.58	$0.94	$0.32	$0.58	$0.94	$1.31	$1.67	$2.19	$0.71	$1.31	$2.19		
44	Transmission Energy	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00		
45																				
46	Generation Demand	$0.04	$0.08	$0.12	$0.17	$0.22	$0.29	$0.08	$0.12	$0.04	$0.08	$0.12	$0.17	$0.22	$0.29	$0.09	$0.17	$0.29		
47	Transmission Demand	$0.00	$0.00	$0.01	$0.01	$0.01	$0.01	$0.00	$0.01	$0.00	$0.00	$0.01	$0.01	$0.01	$0.01	$0.00	$0.01	$0.01		
48																				
49	Distribution-Poles	$0.09	$0.12	$0.18	$0.20	$0.32	$0.44	$0.12	$0.18	$0.09	$0.12	$0.18	$0.20	$0.32	$0.44	$0.09	$0.23	$0.35		
50	Distribution-Conductor	$0.12	$0.16	$0.24	$0.27	$0.43	$0.58	$0.16	$0.24	$0.12	$0.16	$0.24	$0.27	$0.43	$0.58	$0.13	$0.31	$0.47		
51	Distribution-Transformer	$0.03	$0.04	$0.06	$0.07	$0.11	$0.15	$0.04	$0.06	$0.03	$0.04	$0.06	$0.07	$0.11	$0.15	$0.03	$0.08	$0.12		
52																				
53	Distribution-Lighting	$12.85	$13.55	$13.59	$13.69	$14.23	$17.21	$23.45	$23.45	$6.88	$7.17	$7.19	$7.23	$7.41	$8.90	$8.84	$9.75	$11.28		
54																				
55	Customer - Billing	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07	$1.74	$1.74	$1.74		
56	Customer - Metering	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00		
57	Customer - Other	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.58	$0.58	$0.58		
58	Total Lighting Marginal Cost																			
59	Generation Energy	$33,407	$94,838	$16,991	$69,498	$27,245	$29,874	$784	$177	$1,223	$22,665	$15,672	$3,403	$6,248	$1,017	$48,418	$22,057	$9,139	$436,693	$43,519
60	Transmission Energy	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
61																				
62	Generation Demand	$4,394	$12,474	$2,235	$9,141	$3,584	$3,929	$103	$23	$161	$2,981	$2,061	$448	$822	$134	$6,368	$2,901	$1,202	$62,300	$28,798
63	Transmission Demand	$206	$586	$105	$429	$168	$184	$5	$1	$8	$140	$97	$21	$39	$6	$299	$136	$56	$2,925	$1,352
64																				
65	Distribution - Poles	$9,673	$19,238	$3,196	$10,744	$5,202	$5,964	$159	$33	$354	$4,598	$2,948	$526	$1,193	$203	$6,448	$3,930	$1,479	$485	$718
66	Distribution - Conductor	$12,932	$25,719	$4,273	$14,364	$6,954	$7,973	$213	$44	$473	$6,147	$3,941	$703	$1,595	$271	$8,620	$5,254	$1,978	$648	$959
67	Distribution - Transformer	$3,236	$6,435	$1,069	$3,594	$1,740	$1,995	$53	$11	$118	$1,538	$986	$176	$399	$68	$2,157	$1,315	$495	$4,284	$7,799
68																				
69	Distribution-Lighting	$1,351,145	$2,209,299	$245,568	$725,179	$232,361	$235,101	$31,639	$4,409	$26,467	$279,385	$119,760	$18,747	$27,736	$4,140	$603,828	$163,837	$47,134		
70																				
71	Customer - Billing	$7,135	$11,068	$1,226	$3,594	$1,108	$927	$92	$13	$261	$2,645	$1,131	$176	$254	$32	$118,974	$29,264	$7,279	$8,406	$2,731
72	Customer - Metering	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,518
73	Customer - Other	$2,390	$3,708	$411	$1,204	$371	$311	$31	$4	$87	$886	$379	$59	$85	$11	$39,859	$9,804	$2,438	$2,816	$915

Line	Total Lighting Marginal Cost by Schedule	Schs. 51 & 15	Sch. 53	Sch. 54	Total
74					
75					
76	Generation Energy	$402,655	$436,693	$43,519	$882,868
77	Transmission Energy	$0	$0	$0	$0
78					
79	Generation Demand	$52,960	$62,300	$28,798	$144,058
80	Transmission Demand	$2,486	$2,925	$1,352	$6,764
81					
82	Distribution - Poles	$75,889	$485	$718	$77,092
83	Distribution - Conductor	$101,454	$648	$959	$103,061
84	Distribution - Transformer	$25,385	$4,284	$7,799	$37,468
85					
86	Distribution-Lighting	$6,325,738			$6,325,738
87					
88	Customer - Billing	$185,179	$8,406	$2,731	$196,315
89	Customer - Metering	$0	$0	$2,518	$2,518
90	Customer - Other	$62,038	$2,816	$915	$65,769

Index		Escalation Factor
2021	2023	2021 - 2023
1.0406	1.1035	1.0605

Lgt 2

PacifiCorp
Oregon Marginal Cost Study
Street, Area, and Recreational Lighting
Customer Cost Development by Schedule

Line	Calculation Component	Units Description / Function	Schedule 51	15	53	54
1	Units	Average Customers	1,108	5,809	314	102
2						
3						
4	$/Unit	Meters				$24.69
5	$/Unit	Billing	$26.77	$26.77	$26.77	$26.77
6	$/Unit	Meter Reading	$0.00	$0.00	$0.00	$0.00
7	$/Unit	Customer Service / Other	$8.97	$8.97	$8.97	$8.97
8						
9						
10	$	Meters				$2,518
11	$	Billing	$29,661	$155,517	$8,406	$2,731
12	$	Meter Reading	$0	$0	$0	$0
13	$	Customer Service / Other	$9,937	$52,101	$2,816	$915
14						
15						
16	Units	Forecast Average Annual Lamps	36,421	7,443		
17						
18						
19	$/Unit	Billing / Forecast Average Annual Lamps	$0.81	$20.90		
20	$/Unit	Meter Reading / Forecast Average Annual Lamps	$0.00	$0.00		
21	$/Unit	Customer Service / Other / Forecast Average Annual Lamps	$0.27	$7.00		

Lgt 3

Company-Owned LED Lighting Maintenance Costs

	Hours	Rate	Street Lights: Level 1 (0-3,500 LED Equivalent Lumens)	Street Lights: Level 2 (3,501-5,500 LED Equivalent Lumens)	Street Lights: Level 3 (5,501-8,000 LED Equivalent Lumens)	Street Lights: Level 4 (8,001-12,000 LED Equivalent Lumens)	Street Lights: Level 5 (12,001-15,500 LED Equivalent Lumens)	Street Lights: Level 6 (15,501 and Greater LED Equivalent Lumens)	Street Lights: Decorative Series - Level 2 (3,501-5,500 LED Equivalent Lumens)	Street Lights: Decorative Series - Level 3 (5,501-8,000 LED Equivalent Lumens)	Area Lights: Level 1 (0-5,500 LED Equivalent Lumens)	Area Lights: Level 2 (5,501-12,000 LED Equivalent Lumens)	Area Lights: Level 3 (12,001 and Greater LED Equivalent Lumens)
Replace Pole (wood)		$183.56	30'	30'	30'	30'	35'	40'			30'	30'	35'
Material Cost			$472.65	$472.65	$472.65	$472.65	$562.52	$690.70			$472.65	$472.65	$562.52
Labor	7.80	2 man	$1,431.78	$1,431.78	$1,431.78	$1,431.78	$1,431.78	$1,431.78			$1,431.78	$1,431.78	$1,431.78
Total Cost			$1,904.43	$1,904.43	$1,904.43	$1,904.43	$1,994.30	$2,122.48			$1,904.43	$1,904.43	$1,994.30
Annual Frequency			0.011	0.011	0.011	0.011	0.011	0.011			0.008	0.008	0.008
Annual Cost			$21.33	$21.33	$21.33	$21.33	$22.34	$23.77			$15.24	$15.24	$15.95
Replace Pole and arm (metal)			25'	25'	25'	25'	30'	35'	25'	25'			
Material Cost			$652.07	$652.07	$652.07	$652.07	$1,285.45	$2,251.84	$665.60	$665.60			
Labor	6.90	2 man	$1,266.57	$1,266.57	$1,266.57	$1,266.57	$1,266.57	$1,266.57	$1,266.57	$1,266.57			
Total Cost			$1,918.64	$1,918.64	$1,918.64	$1,918.64	$2,552.02	$3,518.41	$1,932.17	$1,932.17			
Annual Frequency			0.005	0.005	0.005	0.005	0.005	0.005	0.004	0.004			
Annual Cost			$9.29	$9.29	$9.29	$9.29	$12.36	$17.04	$6.76	$6.76			
Replace Fiberglass Pole			30'	30'	30'	30'	35'	40'					
Material Cost			$788.32	$788.32	$788.32	$788.32	$948.83	$1,194.55					
Labor	6.20	2 man	$1,138.08	$1,138.08	$1,138.08	$1,138.08	$1,138.08	$1,138.08					
Total Cost			$1,926.40	$1,926.40	$1,926.40	$1,926.40	$2,086.90	$2,332.63					
Annual Frequency			0.005	0.005	0.005	0.005	0.005	0.005					
Annual Cost			$9.63	$9.63	$9.63	$9.63	$10.43	$11.66					
Replace Mast Arm													
Material Cost			$217.13	$217.13	$217.13	$217.13	$217.13	$217.13			$165.19	$165.19	$165.19
Labor	2.20	2 man	$403.83	$403.83	$403.83	$403.83	$403.83	$403.83			$403.83	$403.83	$403.83
Total Cost			$620.96	$620.96	$620.96	$620.96	$620.96	$620.96			$569.03	$569.03	$569.03
Annual Frequency			0.013	0.013	0.013	0.013	0.013	0.013			0.006	0.006	0.006
Annual Cost			$8.07	$8.07	$8.07	$8.07	$8.07	$8.07			$3.41	$3.41	$3.41
Replace Photo Cell													
Material Cost			$20.92	$20.92	$20.92	$20.92	$20.92	$20.92	$20.92	$20.92	$20.92	$20.92	$20.92
Labor	0.70	Single man	$128.49	$128.49	$128.49	$128.49	$128.49	$128.49	$128.49	$128.49	$128.49	$128.49	$128.49
Total Cost			$149.41	$149.41	$149.41	$149.41	$149.41	$149.41	$149.41	$149.41	$149.41	$149.41	$149.41
Annual Frequency			0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050	0.050
Annual Cost			$7.47	$7.47	$7.47	$7.47	$7.47	$7.47	$7.47	$7.47	$7.47	$7.47	$7.47
Replace Luminaire													
Material Cost			$220.48	$286.14	$290.61	$300.08	$358.12	$598.33	$900.00	$900.00	$150.02	$244.00	$395.00
Labor	1.20	Single man	$220.27	$220.27	$220.27	$220.27	$220.27	$220.27	$220.27	$220.27	$220.27	$220.27	$220.27
Total Cost			$440.75	$506.42	$510.88	$520.35	$578.39	$818.60	$1,120.27	$1,120.27	$370.29	$464.27	$615.27
Annual Frequency			0.050	0.050	0.050	0.050	0.040	0.040	0.040	0.040	0.040	0.040	0.040
Annual Cost			$22.04	$25.32	$25.54	$26.02	$23.14	$32.74	$44.81	$44.81	$14.81	$18.57	$24.61
Total Annual Maintenance			$77.83	$81.12	$81.34	$81.81	$83.81	$100.76	$59.04	$59.04	$40.93	$44.69	$51.45
Total Monthly Maintenance			$6.49	$6.76	$6.78	$6.82	$6.98	$8.40	$4.92	$4.92	$3.41	$3.72	$4.29
Total Installation Cost per Lamp			$969.94	$1,035.60	$1,040.07	$1,049.54	$1,107.58	$1,347.79	$2,960.67	$2,960.67	$847.54	$941.52	$1,092.52

Lgt 4

LED Usage Amounts & Area Light Counts by Type

Street and Area Light Energy Consumption by Level of Service			
Street/Area	Level	Annual kWh	Watts
Street	Level 1 (0-3,500 LED Equivalent Lumens)	100	39
Street	Level 2 (3,501-5,500 LED Equivalent Lumens)	183	50
Street	Level 3 (5,501-8,000 LED Equivalent Lumens)	296	75
Street	Level 4 (8,001-12,000 LED Equivalent Lumens)	413	86
Street	Level 5 (12,001-15,500 LED Equivalent Lumens)	525	135
Street	Level 6 (15,501 and Greater LED Equivalent Lumens)	688	185
Street	Dec Series Level 2 (3,501-5,500 LED Equivalent Lumens)	183	50
Street	Dec Series Level 3 (5,501-8,000 LED Equivalent Lumens)	296	75
Street	Cust. Funded Conv. - Level 1 (0-3,500 LED Equivalent Lumens)	100	39
Street	Cust. Funded Conv. - Level 2 (3,501-5,500 LED Equivalent Lumens)	183	50
Street	Cust. Funded Conv. - Level 3 (5,501-8,000 LED Equivalent Lumens)	296	75
Street	Cust. Funded Conv. - Level 4 (8,001-12,000 LED Equivalent Lumens)	413	86
Street	Cust. Funded Conv. - Level 5 (12,001-15,500 LED Equivalent Lumens)	525	135
Street	Cust. Funded Conv. - Level 6 (15,501 and Greater LED Equivalent Lumens)	688	185
Area	Level 1 (0-5,500 LED Equivalent Lumens)	223	40
Area	Level 2 (5,501-12,000 LED Equivalent Lumens)	413	99
Area	Level 3 (12,001 and Greater LED Equivalent Lumens)	688	150

Cust Exp Year

PacifiCorp
Oregon Marginal Cost Study
Summary of Customer and Metering Expenses
December 2023 Dollars

Line	Description	(A) Actual 2016 Dollars	(B) Actual 2017 Dollars	(C) Actual 2018 Dollars	(D) Actual 2019 Dollars	(E) Actual 2020 Dollars	(F) Adjusted 2023 Dollars
							[(A) x 1.1731+ (B) x 1.1467+ (C) x 1.1208+ (D) x 1.0955+ (E) x 1.0708] / 5
	Customer Accounting						
1	901 Supervision	737,727	744,030	776,328	712,826	706,833	$825,298
2	902 Meter Reading Expense	9,736,750	10,573,506	9,772,620	4,869,243	2,245,673	$8,447,779
3	903 Cust Records & Collection	15,397,727	15,201,207	15,706,759	15,074,984	13,295,839	$16,770,053
4	904 Uncollectible Accounts	4,289,333	6,179,088	4,639,879	5,061,708	6,263,999	$5,914,069
5	905 Misc Cust Acct Expense	12,890	3,926	4,809	5,606	8,479	$8,047
6	Total	30,174,427	32,701,757	30,900,395	25,724,366	22,520,822	$31,965,246
7							
8	Customer Service & Info Expense						
9	907 Supervision	88,021	90,935	36,862	2,105	208	$50,275
10	908 Cust Assistance Expense	2,697,239	2,512,406	2,730,139	3,325,682	3,466,926	$3,292,143
11	909 Info & Instructional Expense	887,624	857,417	2,077,877	2,316,089	1,879,350	$1,780,608
12	910 Misc Cust Svc & Info Expense	17,342	1,002	12,955	1,416	541	$7,629
13	Total	3,690,225	3,461,760	4,857,833	5,645,291	5,347,026	$5,130,655
14							$37,095,901
15	Distribution Expenses						
16	586 Meter Expenses	$1,645,292	$1,079,103	$883,546	$655,758	$1,279,281	$1,249,203
17	597 Meter Maintenance	$10,098	$59,787	$85,408	$231,001	$235,870	$136,352
18		$1,655,390	$1,138,890	$968,955	$886,759	$1,515,150	$1,385,555
19							
20							
21	(1) Inflation Adjustment -	1.1731	1.1467	1.1208	1.0955	1.0708	

Source:
Source: State of Oregon results of operations

Cust Exp Sum

PacifiCorp
Oregon Marginal Cost Study
Summary of Customer Accounting Expense
By Schedule
December 2023 Dollars

Line	FERC Account	Description	Calculation Description	(A) Sch. 4 Residential	(B) Sch. 23 General Service	(C) Sch. 28 General Service	(D) Sch. 30 General Service	(E) Sch. 48 General Service	(F) Sch. 41 Irrigation	(G) Streetlighting	(H) Total
1			Average Number of Customers	535,059	84,332	10,462	797	190	4,356	7,333	642,529
2			Write-offs By Schedule	2,229,536	90,828	113,220	51,212	57,250	15,617	-	2,557,663
3											
4											
5	901	Supervision	Account 902 + 903 + 904	$18,585,837	$2,769,465	$630,165	$146,479	$187,628	$168,232	$196,315	$22,684,122
6	901		% of Total 902 + 903 + 904	81.93%	12.21%	2.78%	0.65%	0.83%	0.74%	0.87%	100.00%
7	901		Total 901 $	$676,193	$100,759	$22,927	$5,329	$6,826	$6,121	$7,142	$825,298
8	901		$ Per Customer	$1.26	$1.19	$2.19	$6.69	$35.93	$1.41	$0.97	$1.28
9											
10	902	Meter Reading Expense	902 Weighting Factor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
11	902		Weighted Customers	0	0	0	0	0	0	0	0
12	902		% of Total $	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
13	902		Total 902 $	$0	$0	$0	$0	$0	$0	$0	$0
14	902		$ Per Customer	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
15											
16	903	Cust. Receipts & Collect.	903 Weighting Factor	1.00	1.21	1.40	1.40	11.58	1.21	1.07	
17	903		Weighted Customers	535,059	101,966	14,675	1,118	2,201	5,264	7,821	668,104
18	903		% of Total $	80.09%	15.26%	2.20%	0.17%	0.33%	0.79%	1.17%	100.00%
19	903		Total 903 $	$13,430,494	$2,559,445	$368,367	$28,062	$55,249	$132,121	$196,315	$16,770,053
20	903		$ Per Customer	$25.10	$30.35	$35.21	$35.21	$290.78	$30.33	$26.77	$26.10
21											
22	904	Uncollectibles	Total 904 $	$5,155,343	$210,020	$261,798	$118,417	$132,380	$36,111	$0	$5,914,069
23	904		% of Write-offs	87.17%	3.55%	4.43%	2.00%	2.24%	0.61%	0.00%	100.00%
24	904		$ Per Customer	$9.64	$2.49	$25.02	$148.58	$696.73	$8.29	$0.00	$9.20
25											
26	905	Misc Cust Acct Expense	Account 902 + 903 + 904	$18,585,837	$2,769,465	$630,165	$146,479	$187,628	$168,232	$196,315	$22,684,122
27	905		% of Total 902 + 903 + 904	81.93%	12.21%	2.78%	0.65%	0.83%	0.74%	0.87%	100.00%
28	905		Total 905 $	$6,593	$982	$224	$52	$67	$60	$70	$8,047
29	905		$ Per Customer	$0.01	$0.01	$0.02	$0.07	$0.35	$0.01	$0.01	$0.01
30											
31	907-910	Supervision, Cust. Assist.	Average Number of customers	535,059	84,332	10,462	797	190	4,356	7,333	642,529
32	907-910	Info & Instructional Exp.,	% of Total	83.27%	13.13%	1.63%	0.12%	0.03%	0.68%	1.14%	100.00%
33	907-910	Misc Cust Svc & Info Exp.	Total 907-910 $	$4,272,495	$673,399	$83,540	$6,364	$1,517	$34,783	$58,557	$5,130,655
34	907-910		$ Per Customer	$7.99	$7.99	$7.99	$7.99	$7.99	$7.99	$7.99	$7.99
35											
36											
37	901 - 910		Total 901 - 910 $	$23,541,118	$3,544,606	$736,855	$158,225	$196,038	$209,195	$262,085	$28,648,122
38											
39			$ Per Customer	$44.00	$42.03	$70.43	$198.53	$1,031.78	$48.02	$35.74	$44.59

AG Expenses

PacifiCorp
Oregon Marginal Cost Study
Administrative & General Expense
Loading Factor

Year	(A) Administrative and General Expenses (000)	(B) Electric Plant in Service (000)	(C) Admin. & General to Electric Plant In Service Loading Factor (A) / (B)
2011	$152,657	$22,769,524	0.67%
2012	$188,240	$23,734,237	0.79%
2013	$175,800	$24,578,893	0.72%
2014	$103,887	$25,826,088	0.40%
2015	$134,217	$26,518,617	0.51%
2016	$129,633	$27,064,435	0.48%
2017	$142,110	$27,658,984	0.51%
2018	$135,363	$28,221,394	0.48%
2019	$123,137	$28,629,755	0.43%
2020	$291,921	$30,542,983	0.96%
10 Year Average A&G to EPIS Loading Factor			0.60%

Footnotes:
(A) FERC Form 1 Page 323, line 197
(B) FERC Form 1 Page 207, line 104

Charge 1

PacifiCorp
Oregon Marginal Cost Study
Calculation of Annual Charges

Line	Description	(A) 20 years - Generation	(B) 10 years - Generation	(C) 5 years - Generation	(D) System Transmission	(E) Distribution
1	Levelized Income Taxes	NA	NA	NA	1.05%	0.97%
2	Levelized Property Tax	NA	NA	NA	0.67%	0.64%
3	Total	NA	NA	NA	1.72%	1.61%
4						
5	Levelized Income & Property Taxes	NA	NA	NA	$17.20	$16.10
6	(per $1,000 of Investment)					
7						
8	Expected Life	20	10	5	65	53
9						
10	Nominal Interest Rate	7.21%	7.21%	7.21%	7.21%	7.21%
11						
12	Present Value: Income **	NA	NA	NA	$235.91	$217.66
13	Taxes & Property Taxes per				(PV of $17.20 per year	(PV of $16.10 per year
14	$1,000 of Investment				for 65 years at 7.21%)	for 53 years at 7.21%)
15						
16	Removal Cost Per $1,000 Investment				$179.96	$442.52
17						
18	Present Value: Removal Cost				$1.95	$11.04
19	at End of Useful Life				(PV of $179.96 in	(PV of $442.52 in
20					65 years at 7.21%)	53 years at 7.21%)
21						
22	Investment and Taxes	$1,000.00	$1,000.00	$1,000.00	$1,237.86	$1,228.70
23	w/o PVCD (Line 12 + Line 18 + $1000)					
24						
25	PVCD Factor	NA	NA	NA	0.035405	0.038044
26						
27	PVCD $ (Line 22 x Line 25)	NA	NA	NA	$43.83	$46.75
28						
29	Total (Line 22 + Line 27)	$1,000.00	$1,000.00	$1,000.00	$1,281.69	$1,275.45
30						
31	EOY Annual Charge ***	$75.24	$122.35	$219.16	$61.57	$63.67
32						
33	Annual Economic Carrying	7.52%	12.24%	21.92%	6.16%	6.37%
34	Adm &Gen Expense Loading Factor	0.00%	0.00%	0.00%	0.60%	0.60%
35						
36	Annual Econ Carrying + A&G Loading	7.52%	12.24%	21.92%	6.76%	6.97%

Footnotes:
From Financial Analysis -
** PV = Ln(5) x [1/r - (1/r)/(1+r)^a]
17.20*(1/0.0721-(1/0.0721)/(1+0.0721)^65)
16.10*(1/0.0721-(1/0.0721)/(1+0.0721)^53)
Where:
r = Nominal Interest Rate
a = Expected Investment Life

*** The Annual Charge Formula:
AC% = Ln(11) x k x {1/[1 - 1/(1+k)^a]}/(1+k)
Where:
k = real interest rate = (1 + r) / (1 + i) - 1
i = inflation rate = 2.3%
a = expected investment life
r = nominal interest rate

Charge 2

PacifiCorp
Oregon Marginal Cost Study
Financial Inputs to the Economic Carrying Charge Calculation

	(A)	(B)	(C)	(D)	(E)	(F)
Line	Financial Inputs		Levelized		Weighted Inflation Rate	
1	Weighted Cost of Capital	7.21%	Income Taxes		2021	4.06%
2	Borrowing Rate	7.21%	Transmission	1.05%	2022	3.68%
3	Inflation	2.31%	Distribution	0.97%	2023	2.28%
4			Property Taxes		2024	2.43%
5	Real Cost of Capital		Transmission	0.67%	2025	2.43%
6	(1+0.0721)/(1+0.0231)-1 =	4.79%	Distribution	0.64%	2026	2.36%
7					2027	2.38%
8					2028	2.38%
9					2029	2.36%
10					2030	2.31%
11					2031	2.29%
12					2032	2.23%
13					2033	2.25%
14					2034	2.26%
15					2035	2.27%
16					2036	2.26%
17					2037	2.27%
18					2038	2.27%
19					2039	2.27%
20					2040	2.28%
21					2041	2.27%
22					2042	2.29%
23					2023 thru 2042 Average	2.31%

Source:
Cost of Capital/Borrowing Rate: Revenue Requirement (OR Jurisdictional Allocation Model)
Income & Property Taxes: 2021 Use of Facilities Report
Company Official Inflation Rate Forecast, 4th Quarter 2021

Charge 3

PacifiCorp
Oregon Marginal Cost Study
Present Value of Cost of Dispersion Factor
Iowa Curve R 2 & 65 Year Average Life

Real Cost of Capital = 4.79%

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
YEAR	PVCD	% RENEWED	NUM1	DEM1	NUM1/DEM1	NUM2	DEM2	NUM2/DEM2	INSTANCE	Iowa R 2.0
	((A) {yr-1} +(I)) / 100	((J,{yr-1})-(J)) * 100	(B)	1.0479 ^Year	(C) / (D)	(B)	1.0479 ^62	(F) / (G)	(E) - (H)	(Given)
										100.0000
1	0.000703	7.82%	0.0782	1.047944	0.074578	0.0782	18.237317	0.004285	0.070293	99.9218
2	0.002041	15.63%	0.1563	1.098187	0.142333	0.1563	18.237317	0.008571	0.133762	99.7655
3	0.003313	15.63%	0.1563	1.150838	0.135821	0.1563	18.237317	0.008571	0.127250	99.6092
4	0.004577	16.32%	0.1632	1.206014	0.135347	0.1632	18.237317	0.008950	0.126397	99.4460
5	0.005932	18.40%	0.1840	1.263835	0.145589	0.1840	18.237317	0.010089	0.135499	99.2620
6	0.007220	18.40%	0.1840	1.324428	0.138928	0.1840	18.237317	0.010089	0.128839	99.0780
7	0.008445	18.40%	0.1840	1.387927	0.132572	0.1840	18.237317	0.010089	0.122483	98.8940
8	0.009812	21.60%	0.2160	1.454470	0.148508	0.2160	18.237317	0.011844	0.136664	98.6780
9	0.011111	21.60%	0.2160	1.524203	0.141713	0.2160	18.237317	0.011844	0.129870	98.4620
10	0.012344	21.60%	0.2160	1.597279	0.135230	0.2160	18.237317	0.011844	0.123386	98.2460
11	0.013662	24.28%	0.2428	1.673859	0.145036	0.2428	18.237317	0.013312	0.131724	98.0032
12	0.014959	25.17%	0.2517	1.754111	0.143487	0.2517	18.237317	0.013801	0.129686	97.7515
13	0.016190	25.17%	0.2517	1.838210	0.136923	0.2517	18.237317	0.013801	0.123122	97.4998
14	0.017452	27.18%	0.2718	1.926341	0.141120	0.2718	18.237317	0.014906	0.126214	97.2280
15	0.018738	29.20%	0.2920	2.018697	0.144648	0.2920	18.237317	0.016011	0.128637	96.9360
16	0.019958	29.20%	0.2920	2.115482	0.138030	0.2920	18.237317	0.016011	0.122019	96.6440
17	0.021160	30.33%	0.3033	2.216906	0.136816	0.3033	18.237317	0.016631	0.120185	96.3407
18	0.022427	33.72%	0.3372	2.323194	0.145158	0.3372	18.237317	0.018491	0.126667	96.0035
19	0.023627	33.72%	0.3372	2.434577	0.138517	0.3372	18.237317	0.018491	0.120026	95.6662
20	0.024764	33.72%	0.3372	2.551300	0.132180	0.3372	18.237317	0.018491	0.113689	95.3290
21	0.026000	38.71%	0.3871	2.673620	0.144776	0.3871	18.237317	0.021224	0.123552	94.9419
22	0.027169	38.71%	0.3871	2.801804	0.138153	0.3871	18.237317	0.021224	0.116928	94.5548
23	0.028275	38.71%	0.3871	2.936134	0.131832	0.3871	18.237317	0.021224	0.110608	94.1678
24	0.029434	42.91%	0.4291	3.076904	0.139451	0.4291	18.237317	0.023527	0.115923	93.7387
25	0.030565	44.31%	0.4431	3.224423	0.137413	0.4431	18.237317	0.024295	0.113118	93.2956
26	0.031634	44.31%	0.4431	3.379015	0.131126	0.4431	18.237317	0.024295	0.106831	92.8525
27	0.032712	47.40%	0.4740	3.541018	0.133860	0.4740	18.237317	0.025991	0.107869	92.3785
28	0.033796	50.49%	0.5049	3.710789	0.136069	0.5049	18.237317	0.027686	0.108383	91.8736
29	0.034818	50.49%	0.5049	3.888699	0.129844	0.5049	18.237317	0.027686	0.102157	91.3687
30	0.035813	52.20%	0.5220	4.075139	0.128094	0.5220	18.237317	0.028623	0.099471	90.8467
31	0.036840	57.32%	0.5732	4.270517	0.134230	0.5732	18.237317	0.031432	0.102798	90.2735
32	0.037807	57.32%	0.5732	4.475263	0.128089	0.5732	18.237317	0.031432	0.096657	89.7002
33	0.038715	57.32%	0.5732	4.689825	0.122229	0.5732	18.237317	0.031432	0.090797	89.1270
34	0.039679	64.83%	0.6483	4.914674	0.131913	0.6483	18.237317	0.035548	0.096364	88.4787
35	0.040582	64.83%	0.6483	5.150303	0.125878	0.6483	18.237317	0.035548	0.090329	87.8304
36	0.041428	64.83%	0.6483	5.397229	0.120119	0.6483	18.237317	0.035548	0.084570	87.1821
37	0.042293	70.97%	0.7097	5.655994	0.125476	0.7097	18.237317	0.038914	0.086562	86.4724
38	0.043125	73.02%	0.7302	5.927165	0.123188	0.7302	18.237317	0.040036	0.083151	85.7422
39	0.043900	73.02%	0.7302	6.211337	0.117552	0.7302	18.237317	0.040036	0.077516	85.0121
40	0.044665	77.46%	0.7746	6.509134	0.119004	0.7746	18.237317	0.042474	0.076530	84.2375
41	0.045417	81.91%	0.8191	6.821208	0.120078	0.8191	18.237317	0.044912	0.075166	83.4184
42	0.046114	81.91%	0.8191	7.148244	0.114584	0.8191	18.237317	0.044912	0.069672	82.5993
43	0.046777	84.31%	0.8431	7.490959	0.112546	0.8431	18.237317	0.046228	0.066318	81.7562
44	0.047441	91.51%	0.9151	7.850106	0.116569	0.9151	18.237317	0.050176	0.066393	80.8412
45	0.048051	91.51%	0.9151	8.226471	0.111236	0.9151	18.237317	0.050176	0.061060	79.9261
46	0.048611	91.51%	0.9151	8.620881	0.106147	0.9151	18.237317	0.050176	0.055970	79.0110
47	0.049179	101.66%	1.0166	9.034201	0.112530	1.0166	18.237317	0.055744	0.056786	77.9944
48	0.049695	101.66%	1.0166	9.467337	0.107381	1.0166	18.237317	0.055744	0.051638	76.9778
49	0.050163	101.66%	1.0166	9.921239	0.102469	1.0166	18.237317	0.055744	0.046725	75.9612
50	0.050616	109.65%	1.0965	10.396903	0.105460	1.0965	18.237317	0.060122	0.045339	74.8647
51	0.051031	112.31%	1.1231	10.895372	0.103078	1.1231	18.237317	0.061581	0.041497	73.7416
52	0.051399	112.31%	1.1231	11.417740	0.098362	1.1231	18.237317	0.061581	0.036781	72.6185
53	0.051737	117.74%	1.1774	11.965152	0.098401	1.1774	18.237317	0.064559	0.033842	71.4412
54	0.052044	123.17%	1.2317	12.538810	0.098230	1.2317	18.237317	0.067537	0.030693	70.2095
55	0.052306	123.17%	1.2317	13.139970	0.093736	1.2317	18.237317	0.067537	0.026199	68.9778
56	0.052530	125.87%	1.2587	13.769953	0.091409	1.2587	18.237317	0.069017	0.022391	67.7191
57	0.052724	133.97%	1.3397	14.430140	0.092840	1.3397	18.237317	0.073459	0.019381	66.3794
58	0.052875	133.97%	1.3397	15.121979	0.088592	1.3397	18.237317	0.073459	0.015134	65.0397
59	0.052986	133.97%	1.3397	15.846987	0.084539	1.3397	18.237317	0.073459	0.011080	63.7000
60	0.053064	144.25%	1.4425	16.606755	0.086860	1.4425	18.237317	0.079094	0.007766	62.2575

Charge 4

PacifiCorp
Oregon Marginal Cost Study
Present Value of Cost of Dispersion Factor
Iowa Curve R 2 & 65 Year Average Life
Page 2 of 2

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
YEAR	PVCD	% RENEWED	NUM1	DEM1	NUM1/DEM1	NUM2	DEM2	NUM2/DEM2	INSTANCE	Iowa R 2.0
	((A) {yr-1} +(I)) / 100	((J,{yr-1})-(J)) * 100	(B)	1.0479 ^Year	(C) / (D)	(B)	1.0479 ^62	(F) / (G)	(E) - (H)	(Given)
61	0.053101	144.25%	1.4425	17.402950	0.082886	1.4425	18.237317	0.079094	0.003792	60.8151
62	0.053101	144.25%	1.4425	18.237317	0.079094	1.4425	18.237317	0.079094	0.000000	59.3726
63	0.053064	151.15%	1.5115	19.111687	0.079086	1.5115	18.237317	0.082877	-0.003792	57.8612
64	0.052988	153.45%	1.5345	20.027978	0.076616	1.5345	18.237317	0.084139	-0.007523	56.3267
65	0.052878	153.45%	1.5345	20.988199	0.073111	1.5345	18.237317	0.084139	-0.011028	54.7922
66	0.052731	157.20%	1.5720	21.994458	0.071473	1.5720	18.237317	0.086197	-0.014724	53.2202
67	0.052547	160.95%	1.6095	23.048960	0.069831	1.6095	18.237317	0.088255	-0.018424	51.6107
68	0.052330	160.95%	1.6095	24.154020	0.066636	1.6095	18.237317	0.088255	-0.021619	50.0012
69	0.052082	162.24%	1.6224	25.312061	0.064095	1.6224	18.237317	0.088960	-0.024864	48.3788
70	0.051797	166.09%	1.6609	26.525622	0.062616	1.6609	18.237317	0.091073	-0.028457	46.7178
71	0.051484	166.09%	1.6609	27.797367	0.059751	1.6609	18.237317	0.091073	-0.031322	45.0569
72	0.051143	166.09%	1.6609	29.130084	0.057017	1.6609	18.237317	0.091073	-0.034055	43.3960
73	0.050772	168.18%	1.6818	30.526697	0.055094	1.6818	18.237317	0.092220	-0.037126	41.7142
74	0.050376	168.18%	1.6818	31.990270	0.052574	1.6818	18.237317	0.092220	-0.039646	40.0323
75	0.049955	168.18%	1.6818	33.524011	0.050168	1.6818	18.237317	0.092220	-0.042052	38.3505
76	0.049515	167.10%	1.6710	35.131287	0.047564	1.6710	18.237317	0.091625	-0.044061	36.6795
77	0.049053	166.74%	1.6674	36.815622	0.045290	1.6674	18.237317	0.091427	-0.046137	35.0121
78	0.048571	166.74%	1.6674	38.580710	0.043218	1.6674	18.237317	0.091427	-0.048209	33.3447
79	0.048077	164.06%	1.6406	40.430424	0.040579	1.6406	18.237317	0.089959	-0.049381	31.7041
80	0.047573	161.38%	1.6138	42.368821	0.038090	1.6138	18.237317	0.088491	-0.050401	30.0902
81	0.047052	161.38%	1.6138	44.400152	0.036348	1.6138	18.237317	0.088491	-0.052144	28.4764
82	0.046521	159.09%	1.5909	46.528873	0.034192	1.5909	18.237317	0.087234	-0.053042	26.8855
83	0.045999	152.22%	1.5222	48.759654	0.031217	1.5222	18.237317	0.083464	-0.052246	25.3633
84	0.045462	152.22%	1.5222	51.097388	0.029789	1.5222	18.237317	0.083464	-0.053674	23.8412
85	0.044912	152.22%	1.5222	53.547201	0.028426	1.5222	18.237317	0.083464	-0.055037	22.3190
86	0.044395	139.60%	1.3960	56.114469	0.024878	1.3960	18.237317	0.076546	-0.051669	20.9230
87	0.043867	139.60%	1.3960	58.804822	0.023740	1.3960	18.237317	0.076546	-0.052807	19.5270
88	0.043328	139.60%	1.3960	61.624160	0.022653	1.3960	18.237317	0.076546	-0.053893	18.1310
89	0.042824	128.13%	1.2813	64.578670	0.019841	1.2813	18.237317	0.070257	-0.050416	16.8497
90	0.042326	124.31%	1.2431	67.674830	0.018368	1.2431	18.237317	0.068161	-0.049793	15.6066
91	0.041820	124.31%	1.2431	70.919433	0.017528	1.2431	18.237317	0.068161	-0.050633	14.3635
92	0.041340	115.85%	1.1585	74.319595	0.015588	1.1585	18.237317	0.063521	-0.047934	13.2051
93	0.040889	107.38%	1.0738	77.882775	0.013788	1.0738	18.237317	0.058882	-0.045094	12.1312
94	0.040432	107.38%	1.0738	81.616787	0.013157	1.0738	18.237317	0.058882	-0.045725	11.0574
95	0.039988	103.02%	1.0302	85.529823	0.012045	1.0302	18.237317	0.056490	-0.044445	10.0272
96	0.039595	89.94%	0.8994	89.630466	0.010034	0.8994	18.237317	0.049316	-0.039281	9.1278
97	0.039198	89.94%	0.8994	93.927710	0.009575	0.8994	18.237317	0.049316	-0.039740	8.2284
98	0.038796	89.94%	0.8994	98.430981	0.009137	0.8994	18.237317	0.049316	-0.040178	7.3290
99	0.038467	72.86%	0.7286	103.150157	0.007064	0.7286	18.237317	0.039952	-0.032888	6.6004
100	0.038135	72.86%	0.7286	108.095589	0.006740	0.7286	18.237317	0.039952	-0.033211	5.8718
101	0.037800	72.86%	0.7286	113.278125	0.006432	0.7286	18.237317	0.039952	-0.033520	5.1432
102	0.037517	60.84%	0.6084	118.709133	0.005125	0.6084	18.237317	0.033359	-0.028234	4.5348
103	0.037251	56.83%	0.5683	124.400525	0.004568	0.5683	18.237317	0.031162	-0.026593	3.9665
104	0.036983	56.83%	0.5683	130.364785	0.004359	0.5683	18.237317	0.031162	-0.026802	3.3982
105	0.036748	49.42%	0.4942	136.614995	0.003617	0.4942	18.237317	0.027096	-0.023479	2.9040
106	0.036548	42.00%	0.4200	143.164866	0.002934	0.4200	18.237317	0.023030	-0.020096	2.4840
107	0.036345	42.00%	0.4200	150.028764	0.002799	0.4200	18.237317	0.023030	-0.020230	2.0640
108	0.036158	38.63%	0.3863	157.221744	0.002457	0.3863	18.237317	0.021182	-0.018725	1.6777
109	0.036019	28.52%	0.2852	164.759585	0.001731	0.2852	18.237317	0.015640	-0.013909	1.3925
110	0.035879	28.52%	0.2852	172.658821	0.001652	0.2852	18.237317	0.015640	-0.013988	1.1072
111	0.035738	28.52%	0.2852	180.936777	0.001576	0.2852	18.237317	0.015640	-0.014064	0.8220
112	0.035656	16.68%	0.1668	189.611612	0.000880	0.1668	18.237317	0.009144	-0.008265	0.6552
113	0.035573	16.68%	0.1668	198.702353	0.000839	0.1668	18.237317	0.009144	-0.008305	0.4885
114	0.035489	16.68%	0.1668	208.228940	0.000801	0.1668	18.237317	0.009144	-0.008344	0.3217
115	0.035441	9.57%	0.0957	218.212271	0.000439	0.0957	18.237317	0.005247	-0.004809	0.2260
116	0.035405	7.20%	0.0720	228.674242	0.000315	0.0720	18.237317	0.003948	-0.003633	0.1540
		99.8460	99.8460							

Charge 5

PacifiCorp
Oregon Marginal Cost Study
Present Value of Cost of Dispersion Factor
Iowa Curve R 2 & 53 Year Average Life

Real Cost of Capital = 4.79%

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
YEAR	PVCD	% RENEWED	NUM1	DEM1	NUM1/DEM1	NUM2	DEM2	NUM2/DEM2	INSTANCE	Iowa R 2.0
	((A){yr-1} +(I)) / 100	((J,{yr-1})-(J)) * 100	(B)	1.0479 ^Year	(C) / (D)	(B)	1.0479 ^52	(F) / (G)	(E) - (H)	(Given)
										100.0000
1	0.000831	9.58%	0.0958	1.047944	0.091464	0.0958	11.417740	0.008395	0.083069	99.9042
2	0.002408	19.17%	0.1917	1.098187	0.174559	0.1917	11.417740	0.016789	0.157769	99.7125
3	0.003906	19.17%	0.1917	1.150838	0.166573	0.1917	11.417740	0.016789	0.149783	99.5208
4	0.005542	22.06%	0.2206	1.206014	0.182888	0.2206	11.417740	0.019318	0.163571	99.3002
5	0.007130	22.57%	0.2257	1.263835	0.178552	0.2257	11.417740	0.019764	0.158788	99.0745
6	0.008688	23.35%	0.2335	1.324428	0.176310	0.2335	11.417740	0.020451	0.155858	98.8410
7	0.010365	26.49%	0.2649	1.387927	0.190864	0.2649	11.417740	0.023201	0.167663	98.5761
8	0.011954	26.49%	0.2649	1.454470	0.182132	0.2649	11.417740	0.023201	0.158931	98.3112
9	0.013597	28.90%	0.2890	1.524203	0.189595	0.2890	11.417740	0.025310	0.164285	98.0222
10	0.015259	30.87%	0.3087	1.597279	0.193253	0.3087	11.417740	0.027035	0.166218	97.7135
11	0.016833	30.87%	0.3087	1.673859	0.184412	0.3087	11.417740	0.027035	0.157377	97.4049
12	0.018537	35.32%	0.3532	1.754111	0.201338	0.3532	11.417740	0.030932	0.170407	97.0517
13	0.020172	35.81%	0.3581	1.838210	0.194816	0.3581	11.417740	0.031365	0.163452	96.6936
14	0.021777	37.20%	0.3720	1.926341	0.193102	0.3720	11.417740	0.032579	0.160523	96.3216
15	0.023463	41.36%	0.4136	2.018697	0.204877	0.4136	11.417740	0.036223	0.168654	95.9080
16	0.025056	41.36%	0.4136	2.115482	0.195504	0.4136	11.417740	0.036223	0.159281	95.4944
17	0.026693	45.03%	0.4503	2.216906	0.203105	0.4503	11.417740	0.039435	0.163669	95.0442
18	0.028321	47.47%	0.4747	2.323194	0.204338	0.4747	11.417740	0.041577	0.162761	94.5695
19	0.029855	47.47%	0.4747	2.434577	0.194990	0.4747	11.417740	0.041577	0.153412	94.0947
20	0.031498	54.00%	0.5400	2.551300	0.211642	0.5400	11.417740	0.047292	0.164350	93.5548
21	0.033055	54.34%	0.5434	2.673620	0.203244	0.5434	11.417740	0.047592	0.155651	93.0114
22	0.034580	56.62%	0.5662	2.801804	0.202067	0.5662	11.417740	0.049585	0.152481	92.4452
23	0.036146	61.92%	0.6192	2.936134	0.210905	0.6192	11.417740	0.054235	0.156670	91.8260
24	0.037616	61.92%	0.6192	3.076904	0.201256	0.6192	11.417740	0.054235	0.147021	91.2067
25	0.039116	67.37%	0.6737	3.224423	0.208936	0.6737	11.417740	0.059005	0.149932	90.5330
26	0.040581	70.30%	0.7030	3.379015	0.208054	0.7030	11.417740	0.061573	0.146482	89.8300
27	0.041950	70.30%	0.7030	3.541018	0.198536	0.7030	11.417740	0.061573	0.136963	89.1270
28	0.043397	79.51%	0.7951	3.710789	0.214266	0.7951	11.417740	0.069637	0.144629	88.3319
29	0.044745	79.51%	0.7951	3.888699	0.204463	0.7951	11.417740	0.069637	0.134826	87.5368
30	0.046055	83.02%	0.8302	4.075139	0.203730	0.8302	11.417740	0.072714	0.131016	86.7066
31	0.047368	89.55%	0.8955	4.270517	0.209687	0.8955	11.417740	0.078428	0.131259	85.8111
32	0.048584	89.55%	0.8955	4.475263	0.200094	0.8955	11.417740	0.078428	0.121666	84.9156
33	0.049805	97.18%	0.9718	4.689825	0.207217	0.9718	11.417740	0.085114	0.122103	83.9438
34	0.050969	100.45%	1.0045	4.914674	0.204394	1.0045	11.417740	0.087980	0.116414	82.9393
35	0.052046	101.04%	1.0104	5.150303	0.196186	1.0104	11.417740	0.088495	0.107690	81.9289
36	0.053143	112.23%	1.1223	5.397229	0.207933	1.1223	11.417740	0.098291	0.109642	80.8066
37	0.054144	112.23%	1.1223	5.655994	0.198420	1.1223	11.417740	0.098291	0.100129	79.6844
38	0.055095	117.21%	1.1721	5.927165	0.197746	1.1721	11.417740	0.102654	0.095092	78.5123
39	0.056010	124.68%	1.2468	6.211337	0.200729	1.2468	11.417740	0.109198	0.091531	77.2655
40	0.056834	124.68%	1.2468	6.509134	0.191545	1.2468	11.417740	0.109198	0.082347	76.0187
41	0.057627	134.47%	1.3447	6.821208	0.197138	1.3447	11.417740	0.117774	0.079363	74.6740
42	0.058348	137.74%	1.3774	7.148244	0.192685	1.3774	11.417740	0.120633	0.072052	73.2966
43	0.058986	139.07%	1.3907	7.490959	0.185648	1.3907	11.417740	0.121800	0.063848	71.9059
44	0.059588	151.06%	1.5106	7.850106	0.192426	1.5106	11.417740	0.132300	0.060126	70.3954

Charge 5

PacifiCorp
Oregon Marginal Cost Study
Present Value of Cost of Dispersion Factor
Iowa Curve R 2 & 53 Year Average Life

Real Cost of Capital = 4.79%

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
YEAR	PVCD	% RENEWED	NUM1	DEM1	NUM1/DEM1	NUM2	DEM2	NUM2/DEM2	INSTANCE	Iowa R 2.0
	((A){yr-1} +(I)) / 100	((J,{yr-1})-(J)) * 100	(B)	1.0479 ^Year	(C) / (D)	(B)	1.0479 ^52	(F) / (G)	(E) - (H)	(Given)
45	0.060101	151.06%	1.5106	8.226471	0.183623	1.5106	11.417740	0.132300	0.051323	68.8848
46	0.060547	157.02%	1.5702	8.620881	0.182136	1.5702	11.417740	0.137520	0.044615	67.3146
47	0.060927	164.30%	1.6430	9.034201	0.181867	1.6430	11.417740	0.143901	0.037966	65.6716
48	0.061223	164.30%	1.6430	9.467337	0.173546	1.6430	11.417740	0.143901	0.029646	64.0286
49	0.061453	174.38%	1.7438	9.921239	0.175769	1.7438	11.417740	0.152732	0.023038	62.2848
50	0.061606	176.91%	1.7691	10.396903	0.170152	1.7691	11.417740	0.154939	0.015213	60.5157
51	0.061681	178.60%	1.7860	10.895372	0.163921	1.7860	11.417740	0.156422	0.007499	58.7297
52	0.061681	188.19%	1.8819	11.417740	0.164821	1.8819	11.417740	0.164821	0.000000	56.8478
53	0.061605	188.19%	1.8819	11.965152	0.157281	1.8819	11.417740	0.164821	-0.007541	54.9659
54	0.061454	192.79%	1.9279	12.538810	0.153757	1.9279	11.417740	0.168853	-0.015097	53.0380
55	0.061228	197.40%	1.9740	13.139970	0.150226	1.9740	11.417740	0.172886	-0.022660	51.0641
56	0.060932	197.40%	1.9740	13.769953	0.143353	1.9740	11.417740	0.172886	-0.029533	49.0901
57	0.060562	202.75%	2.0275	14.430140	0.140506	2.0275	11.417740	0.177577	-0.037071	47.0626
58	0.060125	203.70%	2.0370	15.121979	0.134703	2.0370	11.417740	0.178405	-0.043702	45.0256
59	0.059625	204.21%	2.0421	15.846987	0.128864	2.0421	11.417740	0.178854	-0.049990	42.9835
60	0.059060	206.26%	2.0626	16.606755	0.124205	2.0626	11.417740	0.180652	-0.056447	40.9208
61	0.058439	206.26%	2.0626	17.402950	0.118523	2.0626	11.417740	0.180652	-0.062130	38.8582
62	0.057767	205.29%	2.0529	18.237317	0.112565	2.0529	11.417740	0.179798	-0.067233	36.8053
63	0.057046	204.49%	2.0449	19.111687	0.106998	2.0449	11.417740	0.179099	-0.072101	34.7604
64	0.056276	204.49%	2.0449	20.027978	0.102102	2.0449	11.417740	0.179099	-0.076997	32.7155
65	0.055482	198.58%	1.9858	20.988199	0.094616	1.9858	11.417740	0.173923	-0.079308	30.7297
66	0.054649	197.92%	1.9792	21.994458	0.089988	1.9792	11.417740	0.173348	-0.083360	28.7504
67	0.053787	195.11%	1.9511	23.048960	0.084652	1.9511	11.417740	0.170886	-0.086234	26.7993
68	0.052924	186.68%	1.8668	24.154020	0.077287	1.8668	11.417740	0.163499	-0.086212	24.9325
69	0.052027	186.68%	1.8668	25.312061	0.073751	1.8668	11.417740	0.163499	-0.089748	23.0657
70	0.051142	177.40%	1.7740	26.525622	0.066877	1.7740	11.417740	0.155369	-0.088492	21.2918
71	0.050258	171.21%	1.7121	27.797367	0.061591	1.7121	11.417740	0.149949	-0.088357	19.5797
72	0.049347	171.21%	1.7121	29.130084	0.058773	1.7121	11.417740	0.149949	-0.091175	17.8676
73	0.048506	153.39%	1.5339	30.526697	0.050248	1.5339	11.417740	0.134344	-0.084096	16.3337
74	0.047647	152.45%	1.5245	31.990270	0.047656	1.5245	11.417740	0.133523	-0.085867	14.8092
75	0.046803	146.23%	1.4623	33.524011	0.043618	1.4623	11.417740	0.128069	-0.084451	13.3469
76	0.046024	131.70%	1.3170	35.131287	0.037487	1.3170	11.417740	0.115345	-0.077858	12.0299
77	0.045228	131.70%	1.3170	36.815622	0.035772	1.3170	11.417740	0.115345	-0.079573	10.7129
78	0.044502	117.79%	1.1779	38.580710	0.030531	1.1779	11.417740	0.103165	-0.072634	9.5350
79	0.043809	110.30%	1.1030	40.430424	0.027282	1.1030	11.417740	0.096606	-0.069324	8.4320
80	0.043103	110.30%	1.1030	42.368821	0.026034	1.1030	11.417740	0.096606	-0.070572	7.3290
81	0.042522	89.36%	0.8936	44.400152	0.020126	0.8936	11.417740	0.078263	-0.058137	6.4354
82	0.041931	89.36%	0.8936	46.528873	0.019205	0.8936	11.417740	0.078263	-0.059058	5.5418
83	0.041378	82.48%	0.8248	48.759654	0.016915	0.8248	11.417740	0.072236	-0.055321	4.7171
84	0.040904	69.70%	0.6970	51.097388	0.013640	0.6970	11.417740	0.061044	-0.047403	4.0201
85	0.040423	69.70%	0.6970	53.547201	0.013016	0.6970	11.417740	0.061044	-0.048028	3.3231
86	0.040026	56.97%	0.5697	56.114469	0.010152	0.5697	11.417740	0.049893	-0.039741	2.7534
87	0.039663	51.51%	0.5151	58.804822	0.008759	0.5151	11.417740	0.045114	-0.036354	2.2383
88	0.039301	50.68%	0.5068	61.624160	0.008225	0.5068	11.417740	0.044390	-0.036165	1.7315
89	0.039049	34.98%	0.3498	64.578670	0.005417	0.3498	11.417740	0.030638	-0.025221	1.3817
90	0.038794	34.98%	0.3498	67.674830	0.005169	0.3498	11.417740	0.030638	-0.025469	1.0319
91	0.038580	29.17%	0.2917	70.919433	0.004113	0.2917	11.417740	0.025548	-0.021435	0.7402
92	0.038428	20.45%	0.2045	74.319595	0.002752	0.2045	11.417740	0.017913	-0.015161	0.5357
93	0.038275	20.45%	0.2045	77.882775	0.002626	0.2045	11.417740	0.017913	-0.015287	0.3311
94	0.038187	11.74%	0.1174	81.616787	0.001438	0.1174	11.417740	0.010279	-0.008841	0.2138
95	0.038120	8.83%	0.0883	85.529823	0.001032	0.0883	11.417740	0.007734	-0.006701	0.1255
96	0.038058	8.12%	0.0812	89.630466	0.000906	0.0812	11.417740	0.007112	-0.006206	0.0443
97	0.038044	1.74%	0.0174	93.927710	0.000185	0.0174	11.417740	0.001520	-0.001336	0.0269
			99.9731	53.9743						

Charge 6

PACIFICORP
Remaining Life Depreciation Rates

[1] Account Number	[2] Description	[3] 6/30/2021 Balance	[4] IOWA CURVE	[5] Average Life	[6] NET SALVAGE Percent	[7] NET SALVAGE Amount	
		$		Yrs	%	$	
	TRANSMISSION PLANT						
350.20	Land Rights	246,448,855	R4	90.00	0.00%	-	
352.00	Structures & Improvements	313,031,140	R2.5	75.00	-5.00%	(15,651,557)	
353.00	Station Equipment	2,341,673,890	S0	60.00	-10.00%	(234,167,389)	
353.70	Supervisory Equipment	-				-	
354.00	Towers & Fixtures	1,333,441,145	R4	72.00	-8.00%	(106,675,292)	
355.00	Poles & Fixtures	1,109,258,265	R2.5	62.00	-40.00%	(443,703,306)	
356.00	OH Conductors & Devices	1,379,078,572	R2.5	68.00	-30.00%	(413,723,571)	
356.20	Clearing	-				-	
357.00	UG Conduit	3,857,965	S2.5	60.00	0.00%	-	
358.00	UG Conductors & Devices	9,080,617	S2.5	60.00	-5.00%	(454,031)	
359.00	Roads & Trails	12,146,013	R5	75.00	0.00%	-	
	Total Transmission Plant	6,748,016,462		65.30	-18.00%	(1,214,375,146)	
				Use 65 Years			65

[1] Account Number	[2] Description	[3] Balance	[4]	[5]	[6]	
	TRANSMISSION PLANT excludes land accounts					
352.00	Structures & Improvements	313,031,140	2.50	4.81%	0.1204	
353.00	Station Equipment	2,341,673,890	-	36.02%	-	
353.70	Supervisory Equipment	-		0.00%	-	
354.00	Towers & Fixtures	1,333,441,145	4.00	20.51%	0.8204	
355.00	Poles & Fixtures	1,109,258,265	2.50	17.06%	0.4265	
356.00	OH Conductors & Devices	1,379,078,572	2.50	21.21%	0.5303	
356.20	Clearing	-	-	0.00%	-	
357.00	UG Conduit	3,857,965	2.50	0.06%	0.0015	
358.00	UG Conductors & Devices	9,080,617	2.50	0.14%	0.0035	
359.00	Roads & Trails	12,146,013	5.00	0.19%	0.0093	
	Total Transmission Plant	6,501,567,606		100.00%	1.9119	**Use R 2**

PACIFICORP
Remaining Life Depreciation Rates

[1] Account Number	[2] Description	[3] 6/30/2021 Balance	[4] IOWA CURVE	[5] Average Life	[6] NET SALVAGE Percent	[7] NET SALVAGE Amount	
		$		Yrs	%	$	
	DISTRIBUTION PLANT (OREGON)						
360.20	Land Rights	5,274,460	S1.5	70.00	0.00%	-	
361.00	Structures & Improvements	32,761,372	R2	67.00	-10.00%	(3,276,137)	
362.00	Station Equipment	262,150,735	R1	53.00	-20.00%	(52,430,147)	
362.70	Supervisory & Alarm Equipment					-	
364.00	Poles, Towers & Fixtures	452,281,633	R1	58.00	-100.00%	(452,281,633)	
365.00	OH Conductors & Devices	299,985,292	R1	65.00	-50.00%	(149,992,646)	
366.00	UG Conduit	106,676,187	R3	75.00	-45.00%	(48,004,284)	
367.00	UG Conductors & Devices	208,212,087	R2.5	60.00	-35.00%	(72,874,231)	
368.00	Line Transformers	498,477,508	R1.5	46.00	-25.00%	(124,619,377)	
369.10	Overhead Services	106,497,157	R2	60.00	-35.00%	(37,274,005)	
369.20	Underground Services	219,245,299	R4	60.00	-40.00%	(87,698,120)	
370.00	Meters	97,716,304	S3	20.00	-3.00%	(2,931,489)	
371.00	I.O.C.P.	2,666,274	L0	27.00	-50.00%	(1,333,137)	
373.00	Street Lighting & Signal Systems	24,884,170	R1	45.00	30.00%	7,465,251	
	Total OREGON Distribution Plant	2,316,828,478		53.48	-44.25%	(1,025,249,955)	
				Use 53 years			53

[1] Account Number	[2] Description	[3] Balance	[4]	[5]	[6]	
	DISTRIBUTION PLANT excludes land accounts (OREGON)					
361.00	Structures & Improvements	32,761,372	2.00	1.42%	0.03	
362.00	Station Equipment	262,150,735	1.00	11.34%	0.11	
362.70	Supervisory & Alarm Equipment	-		0.00%	0.00	
364.00	Poles, Towers & Fixtures	452,281,633	1.00	19.57%	0.20	
365.00	OH Conductors & Devices	299,985,292	1.00	12.98%	0.13	
366.00	UG Conduit	106,676,187	3.00	4.61%	0.14	
367.00	UG Conductors & Devices	208,212,087	2.50	9.01%	0.23	
368.00	Line Transformers	498,477,508	1.50	21.56%	0.32	
369.10	Overhead Services	106,497,157	2.00	4.61%	0.09	
369.20	Underground Services	219,245,299	4.00	9.48%	0.38	
370.00	Meters	97,716,304	3.00	4.23%	0.13	
371.00	I.O.C.P.	2,666,274	-	0.12%	0.00	
373.00	Street Lighting & Signal Systems	24,884,170	1.00	1.08%	0.01	
	Total OREGON Distribution Plant	2,311,554,018		100.00%	1.76	**Use R 2**

Curves:
R=positive
L=negative
S=0

R means right of the standard
L means left of the standard
S is at the standard

Losses

PacifiCorp
Oregon Marginal Cost Study
Energy Loss Factors

	(A)	(B)	(C)	(D)	(E)
Line	Voltage Level	Energy Factor	Energy Loss Percent	Demand Factor	Demand Loss Percent
1	Transmission	1.03503	3.50%	1.03816	3.82%
2	Primary	1.06294	6.29%	1.07038	7.04%
3	Secondary	1.07965	7.97%	1.08467	8.47%

Cust Data 1

PacifiCorp
Oregon Marginal Cost Study
Customers and MWh @ Sales
12 Months Ended June 30, 2021 - Actual

Line	Description	(A) Del. Volt	(B) Average Customers	(C) % Total Class	(D) Annual MWh's	(E) % Total Class	(F) Average Billing kW	(G) % Total Class
1	Res - Schedule 4	(sec)	519,723	100.0%	5,755,783	100.0%	5,094,228	100.0%
2								
3	GS - Schedule 23							
4	0-15 kW	(sec)	70,227	82.9%	567,191	48.1%	598,673	61.7%
5	15+ kW	(sec)	14,495	17.1%	612,100	51.9%	371,428	38.3%
6	Sec Subtotal		84,722	100.0%	1,179,291	100.0%	970,100	100.0%
7	Primary	(pri)	116		3,443		5,687	
8	Total		84,838		1,182,733		975,787	
9								
10	GS - Schedule 28							
11	0-50 kW	(sec)	4,736	46.4%	442,735	22.2%	269,617	25.4%
12	51-100 kW	(sec)	3,501	34.3%	673,777	33.8%	444,697	41.8%
13	100 + kW	(sec)	1,977	19.4%	876,851	44.0%	349,255	32.8%
14	Sec Subtotal		10,214	100.0%	1,993,363	100.0%	1,063,568	100.0%
15	Primary	(pri)	68		24,061		12,225	
16	Total		10,282		2,017,424		1,075,794	
17								
18	GS - Schedule 30							
19	0-300 kW	(sec)	217	28.7%	186,365	16.2%	63,411	21.0%
20	300+ kW	(sec)	539	71.3%	966,612	83.8%	239,143	79.0%
21	Sec Subtotal		756	100.0%	1,152,977	100.0%	302,554	100.0%
22	Primary	(pri)	53		95,500		24,614	
23	Total		810		1,248,477		327,167	
24								
25	LPS - Schedule 48							
26	1 - 4 MW	(sec)	93	98.9%	503,599	92.9%	119,399	93.6%
27	> 4 MW	(sec)	1	1.1%	38,440	7.1%	8,225	6.4%
28	Sec Subtotal		94	100.0%	542,039	100.0%	127,624	100.0%
29	1 - 4 MW	(pri)	61	68.5%	510,192	34.2%	146,695	39.0%
30	> 4 MW	(pri)	28	31.5%	983,483	65.8%	229,520	61.0%
31	Pri Subtotal		89	100.0%	1,493,675	100.0%	376,215	100.0%
32	Trans	(trn)	8		837,259		309,205	
33	Total		191		2,872,973		813,044	
34								
35	Irrigation - Schedule 41 (Average)	(sec)	3,580	100.0%	237,458	100.0%	211,511	100.0%
36								
37	Irrigation - Schedule 41 (Annual)	(sec)	6,572					

Cust Data 2

PacifiCorp
Oregon Marginal Cost Study
Customers and MWh @ Sales
12 Months Ended December 2023 - Normalized

		(A)	(B)	(C)	(D)	(E)	(F)	(G)
Line	Description	Del. Volt	Average Customers	% Total Class	Annual MWh's	% Total Class	Average Billing kW	% Total Class
1	Res - Schedule 4	(sec)	535,059	100.0%	5,633,856	100.0%	5,094,228	100.0%
2								
3	GS - Schedule 23							
4	0-15 kW	(sec)	69,806	82.9%	545,258	48.1%	598,673	61.7%
5	15+ kW	(sec)	14,408	17.1%	588,429	51.9%	371,428	38.3%
6	Sec Subtotal		84,214	100.0%	1,133,687	100.0%	970,100	100.0%
7	Primary	(pri)	115		3,324		5,687	
8	Total		84,329		1,137,011		975,787	
9								
10	GS - Schedule 28							
11	0-50 kW	(sec)	4,819	46.4%	437,206	22.2%	269,617	25.4%
12	51-100 kW	(sec)	3,562	34.3%	665,361	33.8%	444,697	41.8%
13	100 + kW	(sec)	2,012	19.4%	865,899	44.0%	349,255	32.8%
14	Sec Subtotal		10,393	100.0%	1,968,466	100.0%	1,063,568	100.0%
15	Primary	(pri)	69		23,804		12,225	
16	Total		10,462		1,992,271		1,075,794	
17								
18	GS - Schedule 30							
19	0-300 kW	(sec)	213	28.7%	191,241	16.2%	63,411	21.0%
20	300+ kW	(sec)	531	71.3%	991,901	83.8%	239,143	79.0%
21	Sec Subtotal		744	100.0%	1,183,142	100.0%	302,554	100.0%
22	Primary	(pri)	53		98,439		24,614	
23	Total		797		1,281,581		327,167	
24								
25	LPS - Schedule 48							
26	1 - 4 MW	(sec)	92	98.9%	507,196	92.9%	119,399	93.6%
27	> 4 MW	(sec)	1	1.1%	38,715	7.1%	8,225	6.4%
28	Sec Subtotal		93	100.0%	545,911	100.0%	127,624	100.0%
29	1 - 4 MW	(pri)	61	68.5%	500,164	34.2%	146,695	39.0%
30	> 4 MW	(pri)	28	31.5%	964,153	65.8%	229,520	61.0%
31	Pri Subtotal		89	100.0%	1,464,317	100.0%	376,215	100.0%
32	Trans	(trn)	8		1,545,236		309,205	
33	Total		190		3,555,464		813,044	
34								
35	Irrigation - Schedule 41 (Average)	(sec)	4,356	100.0%	263,565	100.0%	211,511	100.0%
36								
37	Irrigation - Schedule 41 (Annual)	(sec)	7,997	100.0%	263,565	100.0%	211,511	100.0%

Cust Data 3

PacifiCorp
Oregon Marginal Cost Study
Customer Class Split between
Three Phase / Single Phase

Line	Customer Class		(A) Voltage Level	(B) Three Phase	(C) Total Customers	(D) Three Phase % of Customers	(E) Single Phase % of Customers
1	Res - Schedule 4		(sec)	-	519,723	0.0000%	100.0000%
2							
3	GS - Schedule 23						
4	0-15 kW		(sec)	13,464	70,227	19.1716%	80.8284%
5	15+ kW		(sec)	6,617	14,495	45.6506%	54.3494%
6	Sec Subtotal			20,081	84,722		
7	Primary		(pri)	116	116	100.0000%	0.0000%
8		Total		20,196	84,838	23.8060%	76.1940%
9							
10	GS - Schedule 28						
11	0-50 kW		(sec)	3,369	4,736	71.1213%	28.8787%
12	51-100 kW		(sec)	3,056	3,501	87.3107%	12.6893%
13	100 + kW		(sec)	1,946	1,977	98.4362%	1.5638%
14	Sec Subtotal			8,371	10,214		
15	Primary		(pri)	68	68	100.0000%	0.0000%
16		Total		8,439	10,282	82.0761%	17.9239%
17							
18	GS - Schedule 30						
19	0-300 kW			216	217	99.5324%	0.4676%
20	300+ kW			539	539	100.0000%	0.0000%
21	Sec Subtotal			755	756		
22	Primary			53	53	100.0000%	0.0000%
23		Total		809	810	99.8748%	0.1252%
24							
25	LPS - Schedule 48						
26	1 - 4 MW		(sec)	93	93	100.0000%	0.0000%
27	1 - 4 MW		(pri)	61	61	100.0000%	0.0000%
28	> 4 MW		(sec)	1	1	100.0000%	0.0000%
29	> 4 MW		(pri)	28	28	100.0000%	0.0000%
30	Trans		(trn)	8	8	100.0000%	0.0000%
31	Total			191	191	100.0000%	0.0000%
32							
33	Irrigation - Schedule 41 (Annual)		(sec)	5,551	6,569	84.4991%	15.5009%

Cust Data 4

PacifiCorp
Oregon Marginal Cost Study
Cutomer Loads at Sales - MW
12 Months Ended December 2023

Line	Description	(A) Del. Volt	(B)	(C) System Peak	(D)	(E) Weighted Distribution Peak	(F)	(G) Non-Coincident Peak	(H) Cust per Transformer	(I) Coincidence Factor for Winter Loads	(J) Weighted Transformer Peak
1	Res - Schedule 4	(sec)		1,062		1,266		5,094	4	0.67	3,413
2											
3	GS - Schedule 23										
4	0-15 kW	(sec)		85		84		599	3	0.70	419
5	15+ kW	(sec)		92		93		371	3	0.70	260
6	Primary	(pri)		0		0		6	1	1.00	6
7											
8	GS - Schedule 28										
9	0-50 kW	(sec)		67		67		270	1	1.00	270
10	51-100 kW	(sec)		100		98		445	1	1.00	445
11	100 + kW	(sec)		127		125		349	1	1.00	349
12	Primary	(pri)		3		3		12	1	1.00	12
13											
14	GS - Schedule 30										
15	0-300 kW	(sec)		28		28		63	1	1.00	63
16	300+ kW	(sec)		137		137		239	1	1.00	239
17	Primary	(pri)		14		13		25	1	1.00	25
18											
19	LPS - Schedule 48										
20	1 - 4 MW	(sec)		69		70		119	1	1.00	119
21	1 - 4 MW	(pri)		65		66		147	1	1.00	147
22	> 4 MW	(sec)		5		5		8	1	1.00	8
23	> 4 MW	(pri)		117		120		230	1	1.00	230
24	Trans	(trn)		179		179		309	1	1.00	309
25											
26	Irrigation - Sch 41	(sec)		35		62		212	1	1.00	212
27											
28	Customer-Owned Lighting - Sch 53			1		0		3	1	1.00	3
29											
30	Rec Field Lighting - Sch 54			0		0		5	1	1.00	5

Cust per Transformer	Coincidence Factor Summer loads	Coincidence Factor Winter Loads
1	1.00	1.00
2	0.90	0.77
3	0.86	0.70
4	0.82	0.67
5	0.78	0.64
6	0.76	0.62
7	0.74	0.60
8	0.72	0.59
9	0.71	0.58
10	0.70	0.57
11 or more	0.70	0.56

Source: Coincidence Factors -
Distribution Construction Standard, DA 411
(June 30, 2016)

Cust Data 5

PacifiCorp
Oregon Marginal Cost Study
Distribution Substations Monthly Peaks - kW
12 months ended June 2021

A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
														Peak	Peak
Substation		Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Month	Load
Agness Avenue		18,670	17,669	17,753	14,399	15,726	16,050	16,165	15,579	16,119	14,036	13,946	20,002	Jun-21	20,002
Albina		20,299	20,344	20,351	18,257	23,311	18,636	19,045	18,950	18,043	17,427	17,422	23,099	Nov-20	23,311
Alderwood		22,799	22,936	23,072	19,702	16,939	17,561	17,762	18,121	17,295	18,930	19,315	26,041	Jun-21	26,041
Applegate		10,566	10,177	9,875	10,197	12,230	12,751	11,914	11,678	11,350	9,900	8,234	11,408	Dec-20	12,751
Ashland		16,218	16,289	15,662	11,531	14,455	14,748	15,520	15,243	13,927	11,401	12,178	18,448	Jun-21	18,448
Bandon		1,690	1,736	1,816	1,882	2,111	1,932	2,331	2,603	3,108	3,215	2,154	1,785	Apr-21	3,215
Beall Lane		19,544	19,142	19,283	14,452	15,755	15,432	16,158	15,731	14,691	13,261	14,400	20,457	Jun-21	20,457
Belknap		29,464	29,661	30,446	21,786	23,281	23,882	30,618	35,197	33,489	27,214	32,081	46,154	Jun-21	46,154
Bend Plant		18,427	16,183	17,311	13,947	14,329	15,595	15,946	16,759	12,161	10,785	11,936	22,254	Jun-21	22,254
Bloss		8,574	8,942	8,997	8,688	9,425	9,298	10,961	11,643	11,843	10,348	11,520	10,166	Mar-21	11,843
Bond Street		15,605	14,136	14,733	13,849	13,031	14,365	14,436	14,676	12,868	11,456	10,896	21,809	Jun-21	21,809
Brookhurst		37,624	38,040	37,156	23,853	24,979	27,150	25,827	28,770	28,093	23,991	30,550	41,875	Jun-21	41,875
Bryant		22,851	22,769	23,241	17,696	19,176	20,406	23,093	21,162	26,013	16,098	18,520	28,149	Jun-21	28,149
Buchanan		22,739	21,259	22,736	22,532	22,997	23,292	25,550	24,844	21,769	20,507	17,384	27,920	Jun-21	27,920
Buckaroo		19,634	24,394	23,051	20,358	20,857	17,287	18,642	18,212	19,458	16,807	15,532	17,009	Aug-20	24,394
Calapooya		5,462	5,464	5,460	5,267	5,441	5,729	5,612	5,539	5,283	4,999	4,504	6,001	Jun-21	6,001
Campbell		24,437	24,026	24,687	19,373	23,055	16,038	16,446	15,361	14,501	12,852	16,618	23,289	Sep-20	24,687
Cannon Beach		4,808	4,415	4,647	6,882	6,916	6,951	7,146	7,010	6,733	6,503	4,860	4,455	Jan-21	7,146
Canyonville		6,635	6,858	6,153	5,721	5,856	6,700	8,117	7,588	7,976	7,858	6,552	8,218	Jun-21	8,218
Casebeer		7,143	6,786	5,325	3,631	2,879	3,106	3,218	2,995	2,943	5,083	7,835	8,647	Jun-21	8,647
Cave Junction		13,026	12,371	13,029	15,198	16,685	17,287	17,939	17,316	18,383	15,749	12,370	14,339	Mar-21	18,383
Caveman		20,537	18,758	19,612	13,331	14,504	15,124	15,173	14,022	14,739	14,490	14,059	21,698	Jun-21	21,698
Cherry Lane		7,532	7,499	7,347	7,549	7,197	7,269	7,422	7,323	7,406	7,543	7,314	7,283	Oct-20	7,549
China Hat		18,707	16,926	17,136	20,047	19,547	20,306	21,448	21,612	19,636	18,433	15,643	22,708	Jun-21	22,708
Circle Blvd		15,877	13,876	13,865	13,374	12,728	12,105	14,351	14,139	14,423	14,919	14,997	17,387	Jun-21	17,387
Cleveland Ave.		23,425	17,773	30,986	29,276	28,639	29,024	30,657	29,078	19,266	28,592	26,808	37,726	Jun-21	37,726
Cloake		15,140	15,259	14,718	10,302	10,937	11,364	11,494	10,295	10,943	9,311	11,626	17,983	Jun-21	17,983
Coburg		2,347	2,271	2,220	1,800	1,864	2,057	1,978	1,957	1,785	1,646	1,613	2,669	Jun-21	2,669
Columbia		31,691	31,202	28,767	27,507	27,785	29,381	30,187	30,301	28,585	27,152	25,723	33,519	Jun-21	33,519
Coquille		10,097	10,307	10,538	14,615	15,652	16,282	16,114	15,832	15,843	15,378	12,258	13,734	Dec-20	16,282
Cully		16,959	15,031	15,474	11,245	12,374	13,686	16,748	14,955	11,948	8,514	8,849	14,783	Jul-20	16,959
Culver		11,921	11,367	9,672	6,067	10,607	9,406	8,241	9,534	9,048	9,236	9,253	12,834	Jun-21	12,834
Dairy		9,497	8,470	6,598	4,080	1,951	1,918	2,851	2,836	2,868	6,895	8,995	10,111	Jun-21	10,111
Dallas		32,490	32,002	32,124	28,979	32,091	34,343	32,569	34,426	32,147	29,580	26,016	39,591	Jun-21	39,591
Dalreed		31,496	33,608	26,583	15,440	8,098	7,649	7,843	8,113	12,855	18,134	27,254	32,546	Aug-20	33,608
Deschutes		7,992	7,116	7,211	10,933	9,946	11,517	12,026	12,101	10,548	8,916	6,891	9,416	Feb-21	12,101
Devils Lake		20,255	19,421	20,004	28,079	29,640	31,536	32,217	32,116	30,833	28,233	22,730	20,932	Jan-21	32,217
Dixon		3,102	2,854	3,105	2,310	2,223	2,365	2,458	2,509	2,166	2,327	2,468	3,575	Jun-21	3,575
Dodge Bridge		11,321	11,572	11,016	9,981	11,368	11,935	10,431	11,697	15,694	9,258	9,017	12,454	Mar-21	15,694
Dowell		16,037	15,852	15,252	10,513	12,171	12,727	10,431	11,480	11,890	9,258	9,017	12,454	Jul-20	16,037
Easy Valley		19,215	19,912	17,991	14,023	16,682	17,089	16,738	15,759	16,084	13,081	14,942	22,436	Jun-21	22,436
Empire		9,947	8,828	10,418	15,383	17,403	18,606	18,370	18,710	17,895	16,370	12,185	10,479	Feb-21	18,710
Fern Hill		1,782	1,816	2,040	2,751	3,244	3,293	3,362	3,889	2,539	2,400	1,544	1,417	Feb-21	3,889
Fielder Creek		10,843	10,403	10,275	11,325	11,513	11,790	12,164	11,416	12,085	10,819	8,260	12,117	Jan-21	12,164
Foothills Rd		13,819	13,696	13,733	9,388	6,839	9,929	15,808	10,875	9,746	8,989	11,674	15,529	Jan-21	15,808
Garden Valley		14,641	12,247	14,307	10,856	10,600	10,557	10,310	9,553	10,165	9,181	11,120	16,317	Jun-21	16,317
Glendale		9,728	9,712	9,234	12,282	11,925	12,238	11,734	11,736	11,684	11,373	10,549	11,703	Oct-20	12,282
Gold Hill		8,067	7,996	7,819	6,963	8,035	8,495	7,882	7,675	7,629	6,715	6,547	8,668	Jun-21	8,668
Gordon Hollow		4,216	3,745	3,564	3,696	3,482	3,889	3,848	4,690	3,536	3,259	3,250	4,489	Feb-21	4,690
Goshen		5,394	5,386	5,142	5,746	5,561	6,251	6,309	6,143	5,768	5,463	4,155	6,258	Jan-21	6,309
Grant Street		23,397	24,083	24,233	22,577	25,219	26,452	29,174	28,523	23,985	21,096	21,475	28,826	Jan-21	29,174
Green		14,363	14,209	14,054	12,698	12,871	13,417	13,922	12,465	13,470	11,947	11,092	15,604	Jun-21	15,604
Harrisburg		7,680	6,963	7,025	7,480	7,830	8,426	8,538	8,432	8,423	7,104	5,710	8,485	Jan-21	8,538
Hazelwood		6,882	6,893	6,777	6,509	6,530	6,685	6,747	6,581	6,412	5,583	4,804	7,681	Jun-21	7,681
Hillview		28,190	24,613	29,844	22,584	24,049	24,757	23,912	24,989	24,936	20,954	20,670	31,463	Jun-21	31,463
Holladay		22,036	20,807	20,622	18,213	17,148	17,972	18,619	18,787	16,240	16,627	15,606	21,230	Jul-20	22,036
Hollywood		29,897	28,808	28,763	22,186	24,056	25,548	24,136	29,650	24,040	23,818	22,364	35,974	Jun-21	35,974
Hood River		28,611	27,460	27,206	24,959	24,212	31,175	26,571	30,603	24,427	21,559	22,183	35,540	Jun-21	35,540
Hornet		14,202	14,675	15,186	11,080	11,212	11,725	10,749	11,078	11,302	9,782	12,038	17,381	Jun-21	17,381
Independence		20,973	20,513	20,528	16,619	16,946	17,814	18,428	18,988	17,258	15,311	16,531	23,969	Jun-21	23,969
Jacksonville		17,113	17,686	16,720	12,121	14,458	15,057	15,130	14,651	14,060	11,879	13,446	20,264	Jun-21	20,264
Jefferson		8,746	8,793	8,954	9,860	10,413	10,759	10,812	11,209	11,031	10,119	9,887	11,758	Jun-21	11,758
Jerome Prairie		13,368	13,369	12,599	13,313	15,905	15,708	14,381	14,854	15,015	12,636	10,978	15,843	Nov-20	15,905
Junction City		7,763	7,811	7,625	7,943	8,378	8,984	8,821	8,988	8,615	7,580	6,394	8,346	Feb-21	8,988
Knappa Svensen		2,819	2,932	2,838	3,970	4,378	4,498	5,097	4,934	4,703	4,397	3,074	3,471	Jan-21	5,097
Knott		19,580	19,551	19,280	21,075	22,311	23,744	28,965	28,967	24,193	21,484	19,631	31,719	Jun-21	31,719
Lakeport		17,426	17,498	18,089	17,113	17,992	18,392	19,825	19,264	19,102	17,296	16,407	18,452	Jan-21	19,825
Lebanon		30,409	30,908	29,183	27,403	27,303	29,540	28,491	29,369	26,880	25,003	23,760	35,795	Jun-21	35,795
Lincoln		19,347	19,587	18,748	17,973	17,352	17,623	18,885	21,055	18,625	17,424	16,173	22,534	Jun-21	22,534
Lockhart		10,960	12,975	11,462	17,800	20,068	21,649	21,351	21,406	21,756	20,086	14,491	12,029	Mar-21	21,756
Lyons		17,240	17,191	16,176	17,441	18,834	19,023	20,354	19,864	19,953	19,209	17,797	18,398	Jan-21	20,354
Madras		18,495	16,566	16,684	17,490	17,046	17,973	19,540	20,260	16,932	16,669	14,600	21,203	Jun-21	21,203
Mallory		13,173	12,495	12,166	10,091	11,154	11,718	12,392	13,812	10,625	9,363	8,811	15,226	Jun-21	15,226
Marys River		14,171	13,312	13,825	14,470	14,662	15,055	15,080	15,022	14,225	13,120	12,231	14,792	Jan-21	15,080
Medford		24,526	24,011	24,566	18,506	16,986	18,298	18,304	17,677	16,034	16,395	19,167	27,686	Jun-21	27,686
Merlin		22,416	22,015	21,965	24,754	26,893	28,069	29,137	25,571	29,699	21,676	19,455	25,716	Mar-21	29,699
Mile High		9,012	9,097	9,244	10,958	11,431	12,332	12,446	13,511	15,023	15,358	15,612	15,280	May-21	15,612
Murder Creek		33,271	38,085	37,339	30,735	31,290	33,235	32,557	30,707	28,728	26,016	28,899	42,498	Jun-21	42,498
Oak Knoll		18,905	18,988	18,033	14,851	18,388	19,239	19,892	19,749	18,818	14,449	14,256	22,700	Jun-21	22,700
O'Brien		1,323	2,648	1,193	1,389	1,490	1,621	1,630	1,554	1,661	1,428	1,188	1,395	Aug-20	2,648
Overpass		36,881	36,524	34,640	34,361	33,695	35,910	36,946	37,699	34,284	26,986	29,935	38,263	Jun-21	38,263
Pallette		352	348	295	417	477	465	465	486	407	416	292	453	Feb-21	486
Park Street		32,479	31,081	31,419	22,480	25,654	27,995	26,418	25,256	25,788	21,343	22,736	34,659	Jun-21	34,659
Parkrose		27,506	28,512	27,152	23,406	24,883	26,355	27,978	31,467	24,964	22,422	21,327	33,225	Jun-21	33,225
Pendleton		30,352	27,963	24,762	18,658	19,646	21,342	21,170	23,806	21,160	21,770	19,154	33,400	Jun-21	33,400
Pilot Butte		17,667	15,656	16,252	13,779	13,511	15,000	14,635	15,190	12,604	11,354	12,358	20,740	Jun-21	20,740
Prineville		35,517	35,203	32,840	32,722	31,694	36,381	40,005	35,670	32,138	31,935	29,234	40,843	Jun-21	40,843
Prospect Central		1,254	1,738	1,146	1,159	1,382	1,800	5,304	5,530	3,134	4,523	3,695	2,194	Feb-21	5,530
Queen Ave		35,243	35,067	35,252	25,976	28,284	31,010	32,023	31,063	27,641	25,452	28,156	42,219	Jun-21	42,219
REDACTED		821	804	774	759	812	840	865	866	824	825	793	858	Feb-21	866
REDACTED		22,494	27,046	27,562	22,334	19,036	19,565	19,207	18,655	18,344	15,939	14,935	19,730	Sep-20	27,562
REDACTED		7,910	7,873	7,912	8,098	7,994	7,998	10,532	10,261	10,540	8,788	8,842	8,940	Mar-21	10,540
REDACTED		11,028	10,677	10,850	11,289	10,849	11,465	11,683	11,665	12,016	12,137	11,670	11,478	Apr-21	12,137
Redmond 115		37,864	36,796	35,171	35,590	32,892	36,939	38,675	36,886	33,347	31,827	26,933	41,483	Jun-21	41,483
Riddle		15,526	15,309	14,684	16,873	17,370	16,054	17,612	17,380	17,711	15,911	13,479	17,507	Mar-21	17,711
Roseburg		21,550	20,741	20,726	19,229	20,282	20,546	21,252	20,133	20,499	17,668	15,119	24,846	Jun-21	24,846
Ross Ave		6,830	6,634	6,792	5,103	5,334	5,768	6,528	6,028	6,041	5,010	5,390	7,995	Jun-21	7,995
Roxy Ann		14,572	14,822	15,374	9,104	7,850	7,974	8,175	7,207	6,849	6,306	11,396	16,977	Jun-21	16,977
Russelville		28,444	28,162	27,537	23,539	25,949	27,609	29,765	33,495	25,502	23,010	22,229	33,803	Jun-21	33,803
Sage Road		31,500	30,941	31,587	23,996	23,620	28,846	29,179	24,214	22,422	21,262	22,690	34,005	Jun-21	34,005
Scenic		28,885	29,071	28,797	19,132	19,568	21,455	20,016	19,793	18,625	15,803	23,723	32,058	Jun-21	32,058
Scio		5,115	5,314	5,141	4,907	5,132	5,380	5,326	5,361	5,235	4,891	4,263	5,833	Jun-21	5,833
Seaside		14,016	13,983	15,487	17,959	19,715	21,127	21,638	21,131	19,452	18,506	14,816	14,955	Jan-21	21,638
Shevlin Park		22,723	19,952	21,671	16,455	16,947	18,641	18,814	19,343	15,501	13,989	14,751	28,007	Jun-21	28,007

Southgate	13,730	14,435	14,307	12,857	13,351	12,978	14,371	12,762	13,554	12,122	10,919	17,030	Jun-21	17,030
State Street	18,024	18,095	18,730	27,081	31,445	33,596	33,119	32,046	32,628	29,156	23,766	19,005	Dec-20	33,596
Stayton	33,487	33,829	32,050	30,879	31,310	33,753	32,756	32,307	31,694	29,172	25,167	40,815	Jun-21	40,815
Stevens Road	22,798	23,578	22,222	13,608	15,988	17,531	18,383	18,097	15,502	12,876	18,932	26,945	Jun-21	26,945
Sweet Home	22,075	21,989	21,571	25,264	25,484	25,159	24,438	24,361	24,388	22,327	17,081	26,191	Jun-21	26,191
Takelma	8,787	9,082	8,362	8,720	9,932	10,838	10,090	10,544	9,510	8,490	6,929	10,272	Dec-20	10,838
Talent	22,637	22,188	22,531	14,719	17,864	18,979	18,624	18,066	16,736	13,997	14,539	20,947	Jul-20	22,637
Texum	12,177	11,158	12,004	11,375	11,344	12,626	15,313	15,053	11,806	10,042	8,891	12,405	Jan-21	15,313
Umatilla	14,344	13,436	12,766	10,064	9,419	10,376	14,100	14,390	9,464	9,193	12,289	16,055	Jun-21	16,055
Vernon	36,266	34,446	33,303	25,193	27,849	30,068	32,992	33,277	27,071	21,090	21,628	38,048	Jun-21	38,048
Vilas Road	15,661	16,053	16,309	13,060	13,373	14,635	14,619	14,747	13,838	11,533	12,951	17,510	Jun-21	17,510
Village Green	12,528	12,464	12,067	12,793	12,807	13,860	13,996	13,934	13,149	12,389	10,148	15,122	Jun-21	15,122
Vine Street	27,100	22,506	21,689	14,189	15,409	16,923	16,437	20,532	16,935	16,477	21,039	27,204	Jun-21	27,204
Warrenton	16,075	16,899	16,282	16,613	17,979	18,391	19,792	19,722	18,420	17,721	15,639	16,341	Jan-21	19,792
Weston	8,931	10,274	9,117	8,991	8,538	6,192	6,370	6,356	5,928	6,024	4,983	10,058	Aug-20	10,274
Westside	12,593	12,181	11,949	11,658	12,857	13,281	14,399	13,857	13,241	11,760	11,460	15,237	Jun-21	15,237
White City	42,009	41,000	40,072	35,956	36,473	38,272	37,949	38,055	37,150	38,113	33,796	43,384	Jun-21	43,384
Winchester	23,322	24,867	22,684	19,334	20,175	19,529	20,666	19,138	20,129	17,567	16,937	26,217	Jun-21	26,217
Yew Ave	17,566	16,322	16,408	14,853	13,858	16,346	17,140	17,413	14,554	13,635	13,382	21,806	Jun-21	21,806
													Total	
Substation peaks	77,669	70,924	52,249	19,831	39,216	73,467	228,455	55,260	125,626	15,352	15,612	1,782,114	2,555,773	
Weighting Factor	3.04%	2.78%	2.04%	0.78%	1.53%	2.87%	8.94%	2.16%	4.92%	0.60%	0.61%	69.73%	100%	

PacifiCorp
Oregon Marginal Cost Study
Weighted Distribution Peaks
Tied to December 2021 Forecast

A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
		Jul-20 29 17:00	Aug-20 18 15:00	Sep-20 2 16:00	Oct-20 26 08:00	Nov-20 9 09:00	Dec-20 23 09:00	Jan-21 26 09:00	Feb-21 10 09:00	Mar-21 16 08:00	Apr-21 9 07:00	May-21 31 18:00	Jun-21 28 18:00	Sum of 12 Wgt Dist peaks
	Del. Volt													
Res - Schedule 4	(sec)	38.5	28.9	22.9	9.0	19.0	41.4	126.0	27.2	52.4	6.0	6.2	888.0	1,265.5
GS - Schedule 23														
0-15 kW	(sec)	2.9	2.8	2.1	0.6	1.2	2.5	8.2	1.9	4.1	0.4	0.4	56.6	83.7
15+ kW	(sec)	3.3	3.0	2.2	0.6	1.4	2.9	9.6	2.1	4.7	0.4	0.5	62.6	93.3
Primary	(pri)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.3
GS - Schedule 28														
0-50 kW	(sec)	2.2	2.1	1.6	0.5	1.0	1.8	6.4	1.4	3.3	0.4	0.4	45.6	66.7
51-100 kW	(sec)	3.4	3.1	2.3	0.7	1.5	2.8	9.4	2.2	4.9	0.5	0.5	66.7	98.1
100+ kW	(sec)	4.2	4.0	2.9	0.9	2.0	3.8	12.9	2.9	6.5	0.7	0.6	83.8	125.2
Primary	(pri)	0.1	0.1	0.1	0.0	0.1	0.1	0.3	0.1	0.2	0.0	0.0	1.9	3.0
GS - Schedule 30														
0-300 kW	(sec)	0.9	0.9	0.6	0.2	0.5	0.8	2.7	0.6	1.5	0.2	0.1	18.7	27.7
300+ kW	(sec)	4.4	4.5	3.0	1.1	2.4	4.2	13.4	3.2	7.3	0.8	0.6	91.6	136.6
Primary	(pri)	0.5	0.5	0.3	0.1	0.2	0.4	1.4	0.3	0.8	0.1	0.1	8.8	13.4
LPS - Schedule 48														
1 - 4 MW	(sec)	2.2	2.2	1.7	0.6	1.2	2.1	6.3	1.6	3.6	0.5	0.3	48.2	70.4
1 - 4 MW	(pri)	2.1	2.1	1.5	0.6	1.1	1.9	5.7	1.4	3.1	0.4	0.3	45.9	66.2
> 4 MW	(sec)	0.2	0.2	0.1	0.0	0.1	0.1	0.4	0.1	0.2	0.0	0.0	3.4	4.8
> 4 MW	(pri)	3.8	3.8	2.7	0.9	1.7	3.4	10.2	2.6	4.9	0.7	0.5	84.7	120.0
Trans	(trn)	5.8	5.4	3.7	1.5	2.8	5.0	14.5	3.7	8.2	1.1	1.1	126.0	178.9
Irrigation - Sch 41	(sec)	2.6	2.0	1.6	0.1	0.0	0.1	0.2	0.1	0.3	0.1	0.3	54.2	61.7
Customer-Owned Lighting - Sch 53		-	-	-	-	0.0	-	0.0	0.0	-	-	-	-	0.0
Rec Field Lighting - Sch 54		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

PacifiCorp
Oregon Marginal Cost Study
Distribution Peaks @ Sales - MW
Tied to December 2021 Forecast

A	B	C	D	E	F	G	H	I	J	K	L	M	N
		Jul-20 29 17:00	Aug-20 18 15:00	Sep-20 2 16:00	Oct-20 26 08:00	Nov-20 9 09:00	Dec-20 23 09:00	Jan-21 26 09:00	Feb-21 10 09:00	Mar-21 16 08:00	Apr-21 9 07:00	May-21 31 18:00	Jun-21 28 18:00
	Del. Volt												
Res - Schedule 4	(sec)	1,266.6	1,042.3	1,121.1	1,163.8	1,236.7	1,440.6	1,409.3	1,258.7	1,066.3	995.0	1,009.7	1,273.5
GS - Schedule 23													
0-15 kW	(sec)	95.3	100.6	101.6	77.0	77.4	87.6	92.0	85.6	84.1	67.4	67.2	81.2
15+ kW	(sec)	107.2	107.8	110.0	83.7	88.6	100.5	107.4	97.0	95.7	73.4	78.1	89.8
Primary	(pri)	0.4	0.5	0.5	0.5	0.4	0.5	0.5	0.5	0.4	0.4	0.4	0.3
GS - Schedule 28													
0-50 kW	(sec)	72.3	76.2	78.7	62.8	62.2	64.1	71.9	66.5	67.6	58.4	59.6	65.4
51-100 kW	(sec)	110.5	112.3	111.2	94.2	96.7	98.6	105.0	101.6	100.0	87.2	83.7	95.7
100+ kW	(sec)	139.3	143.4	141.9	118.5	128.5	132.0	143.8	135.3	133.1	112.2	104.5	120.2
Primary	(pri)	3.5	3.7	3.8	3.8	3.6	3.7	3.8	3.7	3.6	3.2	2.7	2.7
GS - Schedule 30													
0-300 kW	(sec)	29.7	31.4	29.7	28.8	31.0	28.2	30.5	29.2	29.6	27.2	21.4	26.9
300+ kW	(sec)	145.5	161.7	149.0	143.4	156.4	145.1	149.5	146.6	148.8	139.7	104.9	131.4
Primary	(pri)	14.9	16.3	15.0	15.3	16.2	14.5	15.1	14.7	15.3	14.4	11.2	12.7
LPS - Schedule 48													
1 - 4 MW	(sec)	72.7	79.2	81.2	78.5	79.4	73.2	70.8	72.8	72.4	75.7	50.4	69.2
1 - 4 MW	(pri)	70.2	76.9	75.5	73.9	72.5	67.2	64.0	63.7	63.4	63.1	46.3	65.8
> 4 MW	(sec)	5.0	5.5	5.2	4.9	4.6	4.8	4.6	4.8	4.0	4.8	3.6	4.9
> 4 MW	(pri)	125.6	137.5	130.2	121.0	113.9	118.4	114.3	118.8	99.1	118.4	89.3	121.4
Trans	(trn)	190.9	196.2	183.2	198.5	181.6	173.6	161.9	172.5	166.9	176.6	178.0	180.8
Irrigation - Sch 41	(sec)	86.3	72.0	78.3	13.2	2.5	2.3	2.6	2.6	6.1	16.1	51.6	77.8
Customer-Owned Lighting - Sch 53		-	-	-	-	0.1	-	0.0	0.7	-	-	-	-
Rec Field Lighting - Sch 54		0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.0	0.0

Cust Data 6

PacifiCorp
Oregon Marginal Cost Study
Allocation of Uncollectible Expense between Members of Class
12 Months Ended December 2023

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
			Revenues		Percent of				
		Del.	December 2021		Total Revenues		Allocated Net Uncollectible		
Line	Description	Volt	Commercial	Industrial	Commercial	Industrial	Commercial	Industrial	Total
1	Res - Sch 4	(sec)	-	-	0.00%	0.00%	$0	$0	$2,229,536
2									
3	GS - Sch 23	(sec)	$122,318,322	$1,787,870	24.27%	1.74%	$91,754	-$1,142	$90,612
4	GS - Sch 23	(pri)	$308,103	$23,849	0.06%	0.02%	$231	-$15	$216
5	GS - Sch 23	Total	$122,626,425	$1,811,719	24.33%	1.76%	$91,985	-$1,157	$90,828
6									
7	GS - Sch 28	(sec)	$155,110,117	$6,553,539	30.77%	6.38%	$116,351	-$4,186	$112,166
8	GS - Sch 28	(pri)	$1,710,536	$357,902	0.34%	0.35%	$1,283	-$229	$1,055
9	GS - Sch 28	Total	$156,820,653	$6,911,441	31.11%	6.73%	$117,635	-$4,414	$113,220
10									
11	GS - Sch 30	(sec)	$74,329,134	$12,635,934	14.75%	12.30%	$55,756	-$8,071	$47,685
12	GS - Sch 30	(pri)	$5,865,104	$1,366,429	1.16%	1.33%	$4,400	-$873	$3,527
13	GS - Sch 30	Total	$80,194,238	$14,002,363	15.91%	13.63%	$60,155	-$8,944	$51,212
14									
15	LPS - Sch 48	(sec)	$25,482,818	$15,495,788	5.06%	15.09%	$19,115	-$9,897	$9,218
16	LPS - Sch 48	(pri)	$32,840,740	$63,186,011	6.52%	61.52%	$24,635	-$40,358	-$15,723
17	LPS - Sch 48	(trn)	$86,098,155	$1,296,586	17.08%	1.26%	$64,584	-$828	$63,756
18	LPS - Sch 48	Total	$144,421,713	$79,978,385	28.65%	77.87%	$108,334	-$51,084	$57,250
19									
20	Irg - Sch 41	(sec)	-	$29,193,816	0.00%	100.00%	$0	$15,617	$15,617
21			-	$29,193,816	0.00%	100.00%	$0	$15,617	$15,617
22									
23	Total		$504,063,029	$131,897,724			$378,109	-$49,982	$2,557,663

12 Months Ended June 2021 Net Write-offs	
Residential	$2,229,536
Commercial	$378,109
Industrial	-$65,599
Irrigation	$15,617
Total	2,557,663

Docket No. UE 399
Exhibit PAC/1109
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Target Functionalized Revenues, Billing Determinants and Proposed Rates

March 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	$51,736	$51,736	$51,719
	System Usage- Schedule 200 Related	$3,775	$3,736	$3,736	$3,718
	System Usage- T&A and Schedule 201 Related	$4,451	$4,618	$4,618	$4,620
	Distribution	$257,562	$321,705	$321,705	$321,735
	Other Adjustments	$1,282	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$160,615	$166,946	$166,946	$166,940
	Generation Energy - Net Power Costs (Sch 201)	$123,294	$154,626	$123,294	$123,294
	Total	$597,063	$703,367	$672,036	$672,026
Schedule 23, Small General Service					
	Transmission & Ancillary Services[1]	$8,220	$8,867	$8,867	$8,868
	System Usage- Schedule 200 Related	$694	$728	$728	$728
	System Usage- T&A and Schedule 201 Related	$819	$878	$878	$875
	Distribution	$60,110	$71,409	$71,409	$71,406
	Other Adjustments	$247	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$30,769	$31,741	$31,741	$31,744
	Generation Energy - Net Power Costs (Sch 201)	$23,580	$29,398	$23,580	$23,580
	Total	$124,438	$143,021	$137,203	$137,202
Schedule 28, General Service 31-200kW					
Secondary Voltage					
	Transmission & Ancillary Services[1]	$15,275	$14,801	$14,801	$14,789
	System Usage- Schedule 200 Related	$1,339	$1,363	$1,363	$1,358
	System Usage- T&A and Schedule 201 Related	$1,555	$1,634	$1,634	$1,634
	Distribution	$48,399	$47,426	$47,426	$47,440
	Other Adjustments	$433	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$53,582	$54,271	$54,271	$54,271
	Generation Energy - Net Power Costs (Sch 201)	$41,082	$50,266	$41,082	$41,082
	Total	$161,664	$169,761	$160,576	$160,573
Primary Voltage					
	Transmission & Ancillary Services[1]	$220	$172	$172	$172
	System Usage- Schedule 200 Related	$15	$18	$18	$18
	System Usage- T&A and Schedule 201 Related	$18	$22	$22	$22
	Distribution	$676	$471	$471	$471
	Other Adjustments	$5	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$642	$641	$641	$641
	Generation Energy - Net Power Costs (Sch 201)	$492	$594	$492	$492
	Total	$2,068	$1,918	$1,817	$1,817
Schedule 30, General Service 201-999kW					
Secondary Voltage					
	Transmission & Ancillary Services[1]	$8,377	$8,381	$8,381	$8,377
	System Usage- Schedule 200 Related	$769	$810	$810	$805
	System Usage- T&A and Schedule 201 Related	$899	$963	$963	$958
	Distribution	$21,015	$18,724	$18,724	$18,752
	Other Adjustments	$248	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$31,568	$31,981	$31,981	$31,976
	Generation Energy - Net Power Costs (Sch 201)	$24,089	$29,621	$24,089	$24,089
	Total	$86,965	$90,480	$84,948	$84,957
Primary Voltage					
	Transmission & Ancillary Services[1]	$700	$713	$713	$711
	System Usage- Schedule 200 Related	$63	$68	$68	$68
	System Usage- T&A and Schedule 201 Related	$75	$81	$81	$81
	Distribution	$1,715	$1,475	$1,475	$1,483
	Other Adjustments	$22	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$2,621	$2,652	$2,652	$2,645
	Generation Energy - Net Power Costs (Sch 201)	$2,036	$2,456	$2,036	$2,036
	Total	$7,232	$7,445	$7,024	$7,024
Schedule 41, Agricultural Pumping Service					
	Transmission & Ancillary Services[1]	$1,695	$1,788	$1,788	$1,787
	System Usage- Schedule 200 Related	$150	$177	$177	$177
	System Usage- T&A and Schedule 201 Related	$235	$150	$150	$150
	Distribution	$15,064	$20,423	$20,423	$20,425
	Other Adjustments	$55	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$6,792	$7,027	$7,027	$7,027
	Generation Energy - Net Power Costs (Sch 201)	$5,203	$6,508	$5,203	$5,203
	Total	$29,194	$36,073	$34,767	$34,768

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]	$3,789	$3,774	$3,774	$3,775
	System Usage- Schedule 200 Related	$328	$369	$369	$371
	System Usage- T&A and Schedule 201 Related	$382	$437	$437	$437
	Distribution	$10,763	$10,112	$10,112	$10,115
	Other Adjustments	$118	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$14,485	$14,640	$14,640	$14,633
	Generation Energy - Net Power Costs (Sch 201)	$11,114	$13,560	$11,114	$11,114
	Total	$40,979	$42,891	$40,445	$40,445
Primary Voltage					
	Transmission & Ancillary Services[1]	$9,315	$9,326	$9,326	$9,315
	System Usage- Schedule 200 Related	$864	$950	$950	$952
	System Usage- T&A and Schedule 201 Related	$996	$1,114	$1,114	$1,113
	Distribution	$18,811	$16,580	$16,580	$16,594
	Other Adjustments	$302	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$37,235	$37,871	$37,871	$37,870
	Generation Energy - Net Power Costs (Sch 201)	$28,504	$35,076	$28,504	$28,504
	Total	$96,027	$100,917	$94,345	$94,348
Transmission Voltage					
	Transmission & Ancillary Services[1]	$9,388	$9,035	$9,035	$9,041
	System Usage- Schedule 200 Related	$896	$951	$951	$958
	System Usage- T&A and Schedule 201 Related	$1,020	$1,105	$1,105	$1,113
	Distribution	$10,364	$7,923	$7,923	$7,911
	Other Adjustments	$294	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$37,159	$38,234	$38,234	$38,225
	Generation Energy - Net Power Costs (Sch 201)	$28,274	$35,413	$28,274	$28,274
	Total	$87,395	$92,661	$85,522	$85,523
Schedules 15, 51, 53, 54 Lighting					
Secondary Voltage					
	Transmission & Ancillary Services[1]	$39	$28	$28	$28
	System Usage- Schedule 200 Related	$15	$14	$14	$14
	System Usage- T&A and Schedule 201 Related	$14	$13	$13	$14
	Distribution	$4,102	$3,634	$3,634	$3,633
	Other Adjustments	$4	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$567	$457	$457	$458
	Generation Energy - Net Power Costs (Sch 201)	$410	$424	$410	$410
	Total	$5,151	$4,569	$4,556	$4,558
TOTAL		**$1,238,175**	**$1,393,104**	**$1,323,240**	**$1,323,240**
	Employee Discount	-$341		-$383	-$383
Additional Rate Schedules					
	Schedule 47	$3,974		$3,782	$3,782
	Schedule 848	$1,805		$1,374	$1,374
Total Oregon		**$1,243,614**		**$1,328,013**	**$1,328,013**
			Revenue Increase	**$84,399**	**$84,400**

[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	0.918 ¢	$51,718,802
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	0.066 ¢	$3,718,345
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	0.082 ¢	$4,619,762
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	4.435 ¢	$249,861,535
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			3.648 ¢	$57,363,881
Winter kWh			4,061,381,660	kWh			2.698 ¢	$109,576,077
Subtotal	5,769,399,104	5,755,783,167	5,633,856,479	kWh		$472,487,101		$548,731,840
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		$548,731,840
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		$672,026,005
							Change	$74,962,922
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	0.918 ¢	$119,611
System Usage Charge								
Sch 200 related, per kWh	13,311,491	13,311,491	13,029,509	kWh	0.067 ¢	$8,730	0.066 ¢	$8,599
T&A and Sch 201 related, per kWh	13,311,491	13,311,491	13,029,509	kWh	0.079 ¢	$10,293	0.082 ¢	$10,684
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	4.435 ¢	$577,859
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			3.648 ¢	$132,666
Winter kWh			9,392,822	kWh			2.698 ¢	$253,418
Subtotal	13,311,491	13,311,491	13,029,509	kWh		$1,068,864		$1,239,905
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		$1,239,905
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		$1,530,035
Schedule 201 Employee Discount						($72,533)		($72,533)
Total Employee Discount						($340,502)		($382,509)
							Change	($42,007)

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	0.780 ¢	$8,842,758
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	0.064 ¢	$725,560
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	0.077 ¢	$872,939
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	$5.51	$3,014,416
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	4.109 ¢	$46,583,198
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	2.957 ¢	$26,289,765
All additional kWh, per kWh	254,595,104	252,430,690	244,618,153	kWh	2.128 ¢	$5,205,474	2.195 ¢	$5,369,368
Subtotal	1,179,290,680	1,169,546,266	1,133,686,986	kWh		$100,342,451		$113,314,220
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		$113,314,220
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		$136,831,892
							Change	$12,725,698

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	0.768 ¢	$25,526
System Usage Charge								
Sch 200 related, per kWh	3,442,654	3,442,654	3,323,737	kWh	0.060 ¢	$1,994	0.063 ¢	$2,094
T&A and Sch 201 related, per kWh	3,442,654	3,442,654	3,323,737	kWh	0.071 ¢	$2,360	0.076 ¢	$2,526
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	$5.44	$14,862
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	4.045 ¢	$134,445
Energy Charge - Schedule 200								
1st 3,000 kWh, per kWh	1,866,264	1,866,264	1,804,482	kWh	2.822 ¢	$50,922	2.911 ¢	$52,528
All additional kWh, per kWh	1,576,390	1,576,390	1,519,255	kWh	2.095 ¢	$31,828	2.161 ¢	$32,831
Subtotal	3,442,654	3,442,654	3,323,737	kWh		$268,859		$308,042
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		$308,042
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		$370,481
							Change	$38,528

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	0.069 ¢	$1,358,242
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	0.083 ¢	$1,633,827
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	$34.00	$1,424,566
Load Size 101-300 kW, per month	22,209	22,209	22,586	bill	$84.00	$1,897,224	$82.00	$1,852,052
Load Size > 300 kW, per month	621	621	631	bill	$119.00	$75,089	$117.00	$73,827
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	$3.95	$27,425,063
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	0.395 ¢	$7,775,442
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	2.757 ¢	$54,270,620
Subtotal	1,993,362,624	1,975,519,401	1,968,466,445	kWh		$120,148,701		$119,491,341
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		$119,491,341
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		$160,573,236
							Change	($1,090,423)
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	0.077 ¢	$18,329
T&A and Sch 201 related, per kWh	24,061,378	24,061,378	23,804,268	kWh	0.075 ¢	$17,853	0.091 ¢	$21,662
Distribution Charge								
Basic Charge								
Load Size ≤ 50 kW, per month	164	164	167	bill	$25.00	$4,175	$17.00	$2,839
Load Size 51-100 kW, per month	214	214	217	bill	$43.00	$9,331	$30.00	$6,510
Load Size 101-300 kW, per month	380	380	385	bill	$100.00	$38,500	$70.00	$26,950
Load Size > 300 kW, per month	54	54	55	bill	$143.00	$7,865	$100.00	$5,500
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	$0.80	$12,554
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	$3.42	$352,236
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	0.034 ¢	$8,093
Energy Charge - Schedule 200								
All kWh, per kWh	24,061,378	24,061,378	23,804,268	kWh	2.696 ¢	$641,763	2.693 ¢	$641,049
Subtotal	24,061,378	24,061,378	23,804,268	kWh		$1,570,930		$1,324,471
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		$1,324,471
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		$1,816,743
							Change	($251,696)

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	0.068 ¢	$804,537
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	0.081 ¢	$958,345
Distribution Charge								
Basic Charge								
Load Size ≤ 200 kW, per month	179	179	176	bill	$494.00	$86,944	$438.00	$77,088
Load Size 201-300 kW, per month	2,582	2,582	2,539	bill	$144.00	$365,616	$128.00	$324,992
Load Size > 300 kW, per month	6,313	6,313	6,205	bill	$380.00	$2,357,900	$339.00	$2,103,495
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	$1.55	$1,073,149
>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	$3.72	$12,366,422
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	1.073 ¢	$12,695,113
Subtotal	1,152,976,818	1,142,524,024	1,183,141,965	kWh		$62,627,838		$60,868,353
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		$60,868,353
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		$84,957,123
							Change	($2,007,945)
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	0.069 ¢	$67,923
T&A and Sch 201 related, per kWh	95,500,340	95,500,340	98,439,365	kWh	0.076 ¢	$74,814	0.082 ¢	$80,720
Distribution Charge								
Basic Charge								
Load Size ≤ 200 kW, per month	0	0	0	bill	$481.00	$0	$410.00	$0.00
Load Size 201-300 kW, per month	95	95	93	bill	$151.00	$14,043	$130.00	$12,090.00
Load Size > 300 kW, per month	546	546	538	bill	$393.00	$211,434	$338.00	$181,844.00
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	$1.40	$36,572
>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	$3.59	$1,005,491
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	1.037 ¢	$1,020,816
Subtotal	95,500,340	95,500,340	98,439,365	kWh		$5,174,149		$4,988,215
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		$4,988,215
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		$7,023,941
							Change	($207,591)

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	263,527,024	kWh	0.643 ¢	$1,694,479	0.678 ¢	$1,786,713
System Usage Charge								
Sch 200 related, per kWh	237,425,712	224,330,512	263,527,024	kWh	0.057 ¢	$150,210	0.067 ¢	$176,563
T&A and Sch 201 related, per kWh	237,425,712	224,330,512	263,527,024	kWh	0.089 ¢	$234,539	0.057 ¢	$150,210
Distribution Charge								
Basic Charge (billed in November)								
Load Size ≤ 50 kW, or Single Phase Any Size	5,576	5,576	6,786	bill	No Charge	$0	No Charge	$0
Three Phase Load Size 51 - 300 kW, per customer	974	974	1,185	bill	$360.00	$426,600	$490.00	$580,650
Three Phase Load Size > 300 kW, per customer	19	19	23	bill	$1,420.00	$32,660	$1,930.00	$44,390
Total Customers	6,569	6,569	7,994	bill				
Monthly Bills	42,934	42,934	52,248					
Load Size Charge (billed in November)								
Single Phase Any Size, Three Phase ≤ 50 kW	94,969	94,969	111,563	kW	$17.10	$1,907,727	$17.10	$1,907,727
Three Phase Load Size 51-300 kW, per kW	86,214	86,214	101,278	kW	$11.70	$1,184,953	$11.70	$1,184,953
Three Phase Load Size > 300 kW, per kW	8,433	8,433	9,906	kW	$7.20	$71,323	$7.20	$71,323
Single Phase, Minimum Charge	377	377	459	bill	$65.00	$29,835	$90.00	$41,310
Three Phase, Minimum Charge	1,457	1,457	1,773	bill	$105.00	$186,165	$140.00	$248,220
Distribution Energy Charge, per kWh	237,425,712	224,330,512	263,527,024	kWh	4.197 ¢	$11,060,229	6.140 ¢	$16,180,559
Reactive Power Charge, per kvar	211,414	211,414	248,354	kvar	65.00 ¢	$161,430	65.00 ¢	$161,430
Energy Charge - Schedule 200								
All kWh, per kWh	237,425,712	224,330,512	263,527,024	kWh	2.577 ¢	$6,791,091	2.666 ¢	$7,025,630
Subtotal	237,425,712	224,330,512	263,527,024	kWh		$23,931,241		$29,559,678
TAM Adj for Other Revs (205)	237,425,712	224,330,512	263,527,024	kWh	0.021 ¢	$55,341	0.000 ¢	$0
Subtotal						$23,986,582		$29,559,678
Schedule 201								
All kWh, per kWh	237,425,712	224,330,512	263,527,024	kWh	1.974 ¢	$5,202,023	1.974 ¢	$5,202,023
Option A Summer On Peak Adder, per On-peak kWh	19,903,136	18,805,380	22,091,180	kWh	4.989 ¢	$1,102,129	4.989 ¢	$1,102,129
Option B Summer On Peak Adder, per On-peak kWh	19,465,341	18,391,732	21,605,257	kWh	4.989 ¢	$1,077,886	4.989 ¢	$1,077,886
Summer Off Peak Adder, per Off-peak kWh	198,057,235	187,133,400	219,830,587	kWh	-0.992 ¢	($2,180,719)	-0.992 ¢	($2,180,719)
Total	237,425,712	224,330,512	263,527,024	kWh		$29,188,605		$34,761,701
							Change	$5,573,096
Schedule No. 41/741 - Irrigation								
Agricultural Pumping Service (Primary)								
Transmission & Ancillary Services Charge								
per kWh	32,387	32,387	38,046	kWh	0.633 ¢	$241	0.668 ¢	$254
System Usage Charge								
Sch 200 related, per kWh	32,387	32,387	38,046	kWh	0.056 ¢	$21	0.066 ¢	$25
T&A and Sch 201 related, per kWh	32,387	32,387	38,046	kWh	0.088 ¢	$33	0.056 ¢	$21
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	$480.00	$480
Three Phase Load Size > 300 kW, per customer	0	0	0	bill	$1,400.00	$0	$1,900.00	$0
Total Customers	3	3	3	bill				
Monthly Bills	24	24	24					
Load Size Charge (billed in November)								
Single Phase Any Size, Three Phase ≤ 50 kW	12	12	14	kW	$16.90	$237	$16.90	$237
Three Phase Load Size 51-300 kW, per kW	72	72	85	kW	$11.50	$978	$11.50	$978
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	$90.00	$0
Three Phase, Minimum Charge	0	0	0	bill	$105.00	$0	$140.00	$0
Distribution Energy Charge, per kWh	32,387	32,387	38,046	kWh	4.132 ¢	$1,572	6.045 ¢	$2,300
Reactive Power Charge, per kvar	81	81	95	kvar	60.00 ¢	$57	60.00 ¢	$57
Energy Charge - Schedule 200								
All kWh, per kWh	32,387	32,387	38,046	kWh	2.537 ¢	$965	2.625 ¢	$999
Subtotal	32,387	32,387	38,046	kWh		$4,464		$5,351
TAM Adj for Other Revs (205)	32,387	32,387	38,046	kWh	0.020 ¢	$8	0.000 ¢	$0
Subtotal						$4,472		$5,351
Schedule 201								
All kWh, per kWh	32,387	32,387	38,046	kWh	1.943 ¢	$739	1.943 ¢	$739
Option A Summer On Peak Adder, per On-peak kWh	2,715	2,715	3,189	kWh	4.989 ¢	$159	4.989 ¢	$159
Option B Summer On Peak Adder, per On-peak kWh	2,655	2,655	3,119	kWh	4.989 ¢	$156	4.989 ¢	$156
Summer Off Peak Adder, per Off-peak kWh	27,017	27,017	31,737	kWh	-0.992 ¢	($315)	-0.992 ¢	($315)
Total	32,387	32,387	38,046	kWh		$5,211		$6,090
							Change	$879

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. 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	0.065 ¢	$9,732
T&A and Sch 201 related, per kWh	14,646,249	14,646,249	14,971,570	kWh	0.068 ¢	$10,181	0.076 ¢	$11,378
Distribution Charge								
Basic Charge								
Facility Capacity ≤ 4,000 kW, per month	0	0	0	bill	$550.00	$0	$530.00	$0
Facility Capacity > 4,000 kW, per month	12	12	12	bill	$1,490.00	$17,880	$1,470.00	$17,640
Facilities Charge								
Facility Capacity ≤ 4,000 kW, per kW	0	0	0	kW	$1.30	$0	$1.25	$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	$1.74	$151,850
On-Peak, per on-peak kWh	6,118,478	6,118,478	6,254,381	kWh	2.179 ¢	$136,283	2.216 ¢	$138,597
Off-Peak, per off-peak kWh	8,527,771	8,527,771	8,717,189	kWh	2.179 ¢	$189,948	2.216 ¢	$193,173
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		$1,259,183
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		$1,259,183
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		$1,554,634
							Change	($52,463)
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	$3.11	$422,011
credit per kW of on-peak demand (OATT)	0	0	0	kW	($3.25)	$0	($3.11)	$0
System Usage Charge								
Sch 200 related, per kWh	12,828,129	12,828,129	12,903,938	kWh	0.058 ¢	$7,484	0.062 ¢	$8,000
T&A and Sch 201 related, per kWh	12,828,129	12,828,129	12,903,938	kWh	0.066 ¢	$8,517	0.072 ¢	$9,291
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	$2.04	$276,818
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	$1.77	$240,180
On-Peak, per on-peak kWh	4,632,668	4,632,668	4,661,426	kWh	2.129 ¢	$99,242	2.190 ¢	$102,085
Off-Peak, per off-peak kWh	8,195,461	8,195,461	8,242,512	kWh	2.129 ¢	$175,483	2.190 ¢	$180,511
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		$1,992,151
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		$1,992,151
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		$2,226,943
							Change	($139,828)

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. 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	$0.133	$0
Primary	0	0	0	kW	$0.169	$0	$0.142	$0
Transmission	0	0	0	kW	$0.118	$0	$0.079	$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	1,362,855	kW	$2.78	$3,788,737	$2.77	$3,775,108
System Usage Charge								
Sch 200 related, per kWh	542,038,800	524,746,272	545,910,976	kWh	0.060 ¢	$327,547	0.068 ¢	$371,219
T&A and Sch 201 related, per kWh	542,038,800	524,746,272	545,910,976	kWh	0.070 ¢	$382,138	0.080 ¢	$436,729
Distribution Charge								
Basic Charge								
Facility Capacity ≤ 4,000 kW, per month	1,111	1,111	1,109	bill	$580.00	$643,220	$540.00	$598,860
Facility Capacity > 4,000 kW, per month	12	12	13	bill	$1,600.00	$20,800	$1,500.00	$19,500
Facilities Charge								
Facility Capacity ≤ 4,000 kW, per kW	1,461,164	1,461,164	1,517,139	kW	$2.70	$4,096,275	$2.95	$4,475,560
Facility Capacity > 4,000 kW, per kW	154,726	154,726	182,513	kW	$0.80	$146,010	$0.80	$146,010
Demand Charge, per kW of on-peak demand	1,310,991	1,310,991	1,362,855	kW	$4.14	$5,642,220	$3.42	$4,660,964
Reactive Power Charge, per kvar	331,372	331,372	329,766	kvar	65.00 ¢	$214,348	65.00 ¢	$214,348
Energy Charge - Schedule 200								
Demand Charge, per kW of On-Peak demand	1,310,991	1,310,991	1,362,855	kW	$1.64	$2,235,082	$1.66	$2,262,339
On-Peak, per on-peak kWh	206,565,779	199,974,779	208,040,254	kWh	2.244 ¢	$4,668,423	2.266 ¢	$4,714,192
Off-Peak, per off-peak kWh	335,473,021	324,771,493	337,870,722	kWh	2.244 ¢	$7,581,819	2.266 ¢	$7,656,151
Subtotal	542,038,800	524,746,272	545,910,976	kWh		$29,746,619		$29,330,980
TAM Adj for Other Revs (205)								
On-Peak, per on-peak kWh	206,565,779	199,974,779	208,040,254	kWh	0.026 ¢	$54,090	0.000 ¢	$0
Off-Peak, per off-peak kWh	335,473,021	324,771,493	337,870,722	kWh	0.019 ¢	$64,195	0.000 ¢	$0
Subtotal						$29,864,904		$29,330,980
Schedule 201								
On-Peak, per on-peak kWh	206,565,779	199,974,779	208,040,254	kWh	2.461 ¢	$5,119,871	2.461 ¢	$5,119,871
Off-Peak, per off-peak kWh	335,473,021	324,771,493	337,870,722	kWh	1.774 ¢	$5,993,827	1.774 ¢	$5,993,827
Total	542,038,800	524,746,272	545,910,976	kWh		$40,978,602		$40,444,678
							Change	($533,924)
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	3,115,332	kW	$2.99	$9,314,843	$2.99	$9,314,843
System Usage Charge								
Sch 200 related, per kWh	1,493,674,734	1,493,674,734	1,464,317,070	kWh	0.059 ¢	$863,947	0.065 ¢	$951,806
T&A and Sch 201 related, per kWh	1,493,674,734	1,493,674,734	1,464,317,070	kWh	0.068 ¢	$995,736	0.076 ¢	$1,112,881
Distribution Charge								
Basic Charge								
Facility Capacity ≤ 4,000 kW, per month	744	744	743	bill	$550.00	$408,650	$530.00	$393,790
Facility Capacity > 4,000 kW, per month	329	329	327	bill	$1,490.00	$487,230	$1,470.00	$480,690
Facilities Charge								
Facility Capacity ≤ 4,000 kW, per kW	1,478,553	1,478,553	1,534,384	kW	$1.30	$1,994,699	$1.25	$1,917,980
Facility Capacity > 4,000 kW, per kW	2,445,708	2,445,708	2,348,180	kW	$0.85	$1,995,953	$0.85	$1,995,953
Demand Charge, per kW of on-peak demand	3,170,854	3,170,854	3,115,332	kW	$4.33	$13,489,388	$3.65	$11,370,962
Reactive Power Charge, per kvar	757,050	757,050	725,113	kvar	60.00 ¢	$435,068	60.00 ¢	$435,068
Energy Charge - Schedule 200								
Demand Charge, per kW of On-Peak demand	3,170,854	3,170,854	3,115,332	kW	$1.71	$5,327,218	$1.74	$5,420,678
On-Peak, per on-peak kWh	565,736,213	565,736,213	554,616,861	kWh	2.179 ¢	$12,085,101	2.216 ¢	$12,290,310
Off-Peak, per off-peak kWh	927,938,521	927,938,521	909,700,209	kWh	2.179 ¢	$19,822,368	2.216 ¢	$20,158,957
Subtotal	1,493,674,734	1,493,674,734	1,464,317,070	kWh		$67,220,201		$65,843,918
TAM Adj for Other Revs (205)								
On-Peak, per on-peak kWh	565,736,213	565,736,213	554,616,861	kWh	0.025 ¢	$138,654	0.000 ¢	$0
Off-Peak, per off-peak kWh	927,938,521	927,938,521	909,700,209	kWh	0.018 ¢	$163,746	0.000 ¢	$0
Subtotal						$67,522,601		$65,843,918
Schedule 201								
On-Peak, per on-peak kWh	565,736,213	565,736,213	554,616,861	kWh	2.374 ¢	$13,166,604	2.374 ¢	$13,166,604
Off-Peak, per off-peak kWh	927,938,521	927,938,521	909,700,209	kWh	1.686 ¢	$15,337,546	1.686 ¢	$15,337,546
Total	1,493,674,734	1,493,674,734	1,464,317,070	kWh		$96,026,751		$94,348,068
							Change	($1,678,683)

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	$3.65	$9,041,459
System Usage Charge								
Sch 200 related, per kWh	837,259,000	837,259,000	1,545,235,788	kWh	0.058 ¢	$896,237	0.062 ¢	$958,046
T&A and Sch 201 related, per kWh	837,259,000	837,259,000	1,545,235,788	kWh	0.066 ¢	$1,019,856	0.072 ¢	$1,112,570
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	$2.04	$5,053,308
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	$1.77	$4,384,488
On-Peak, per on-peak kWh	314,998,786	314,998,786	581,207,821	kWh	2.129 ¢	$12,373,915	2.190 ¢	$12,728,451
Off-Peak, per off-peak kWh	522,260,214	522,260,214	964,027,967	kWh	2.129 ¢	$20,524,155	2.190 ¢	$21,112,212
Subtotal	837,259,000	837,259,000	1,545,235,788	kWh		$58,826,640		$57,248,475
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		$57,248,475
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		$85,522,839
							Change	($1,871,899)
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	$2.04	$889,499
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		$1,373,638
TAM Adj for Other Revs (205)								
On-Peak, per on-peak kWh				kWh				
Off-Peak, per off-peak kWh				kWh				
Subtotal						$1,805,307		$1,373,638
Schedule 201								
On-Peak, per on-peak kWh				kWh				
Off-Peak, per off-peak kWh				kWh				
Total				kWh		$1,805,307		$1,373,638
Energy Delivered	274,597,000	274,597,000	286,470,860				Change	($431,669)

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	0.065 ¢	$5,346
System Usage Charge								
Sch 200 related, per kWh	8,475,916	8,475,916	8,259,954	kWh	0.031 ¢	$2,544	0.028 ¢	$2,331
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	7.840 ¢	$647,591
Energy Charge - Schedule 200								
per kWh	8,475,916	8,475,916	8,259,954	kWh	1.159 ¢	$95,635	0.984 ¢	$81,299
Subtotal	8,475,916	8,475,916	8,259,954	kWh		$844,575		$738,857
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		$738,857
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		$808,583
							Change	($106,461)
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	0.043 ¢	$10,279
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	10.462 ¢	$2,499,660
Energy Charge - Schedule 200								
per kWh	24,436,047	24,436,047	23,892,579	kWh	1.674 ¢	$399,987	1.320 ¢	$315,359
Subtotal	24,436,047	24,436,047	23,892,579	kWh		$3,259,506		$2,854,241
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		$2,854,241
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		$3,090,143
							Change	($407,415)
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	0.014 ¢	$1,603
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	3.759 ¢	$430,472
Energy Charge - Schedule 200								
per kWh	10,736,096	10,736,096	11,451,780	kWh	0.555 ¢	$63,557	0.473 ¢	$54,167
Subtotal	10,736,096	10,736,096	11,451,780	kWh		$560,679		$491,167
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		$491,167
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		$586,217
							Change	($70,543)
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	0.018 ¢	$205
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	4.090 ¢	$46,677
Energy Charge - Schedule 200								
per kWh	1,310,533	1,310,533	1,141,242	kWh	0.699 ¢	$7,977	0.610 ¢	$6,962
Subtotal	1,310,533	1,310,533	1,141,242	kWh		$72,060		$63,102
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		$63,102
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		$72,574
							Change	($9,061)
Subtotal Oregon	13,402,158,727	13,320,114,631	13,937,602,352			$1,243,954,007		$1,328,395,528
Employee Discount						($340,502)		($382,509)
TOTAL OREGON	**13,402,158,727**	**13,320,114,631**	**13,937,602,352**			**$1,243,613,505**		**$1,328,013,019**
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/1110
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Estimated Effect of Proposed Rates

March 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	$672,026	($10,310)	$661,716	$74,963	12.6%	$54,915	9.1%	1
2	**Total Residential**			535,059	5,633,856	$597,063	$9,738	$606,801	$672,026	($10,310)	$661,716	$74,963	12.6%	$54,915	9.1%	2
	Commercial & Industrial															
3	Gen. Svc. < 31 kW	23	23	84,329	1,137,011	$124,438	$1,015	$125,453	$137,202	$216	$137,418	$12,764	10.3%	$11,965	9.5%	3
4	Gen. Svc. 31 - 200 kW	28	28	10,462	1,992,271	$163,732	$9,197	$172,929	$162,390	$10,519	$172,909	($1,342)	-0.8%	($20)	0.0%	4
5	Gen. Svc. 201 - 999 kW	30	30	797	1,281,581	$94,197	$4,696	$98,893	$91,981	$6,882	$98,863	($2,216)	-2.4%	($30)	0.0%	5
6	Large General Service >= 1,000 kW	48	48	190	3,555,464	$224,400	($15,394)	$209,007	$220,316	$1,209	$221,524	($4,085)	-1.9%	$12,518	5.9%	6
7	Partial Req. Svc. >= 1,000 kW	47	47	6	29,109	$3,974	($120)	$3,854	$3,782	$10	$3,791	($192)	-1.9%	($63)	5.9%	7
8	Dist. Only Lg Gen Svc >= 1,000 kW	848	848	1	0	$1,805	$10	$1,815	$1,374	$0	$1,374	($432)	-23.9%	($441)	-24.3%	8
9	Agricultural Pumping Service	41	41	7,997	263,565	$29,194	($3,645)	$25,549	$34,768	($5,856)	$28,911	$5,574	19.1%	$3,362	13.2%	9
10	**Total Commercial & Industrial**			103,782	8,259,000	$641,740	($4,241)	$637,499	$651,812	$12,980	$664,792	$10,072	1.6%	$27,292	4.3%	10
	Lighting															
11	Outdoor Area Lighting Service	15	15	5,809	8,260	$915	$74	$989	$809	$181	$990	($106)	-11.6%	$0	0.0%	11
12	Street Lighting Service Comp. Owned	51	51	1,108	23,893	$3,498	$387	$3,885	$3,090	$795	$3,885	($407)	-11.7%	$0	0.0%	12
13	Street Lighting Service Cust. Owned	53	53	314	11,452	$657	$210	$867	$586	$280	$867	($71)	-10.7%	$0	0.0%	13
14	Recreational Field Lighting	54	54	102	1,141	$82	$27	$108	$73	$36	$108	($9)	-11.1%	$0	0.0%	14
15	**Total Public Street Lighting**			7,333	44,746	$5,151	$698	$5,849	$4,558	$1,292	$5,850	($593)	-11.5%	$0	0.0%	15
16	**Subtotal**			646,174	13,937,602	$1,243,954	$6,196	$1,250,150	$1,328,396	$3,962	$1,332,357	$84,442	6.8%	$82,208	6.6%	16
17	Emplolyee Discount			*966*	*13,030*	($341)	($6)	($346)	($383)	$6	($383)	($42)		($36)		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**			646,174	13,937,602	$1,248,901	$6,190	$1,255,091	$1,333,301	$3,968	$1,337,262	$84,400	6.8%	$82,171	6.6%	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)	Repl Mtr Def Adj 194 ($000)	Tax Act 195 ($000)	Deer Cr Def Adj 198 ($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)
				PRE							PRE	PRO	PRE	PRO
	Residential													
1	Residential	4	4	$3,259	$1,859	($3,549)	$845	$282	$1,746	$225	$5,070	($11,718)	$9,738	($10,310)
2	**Total Residential**			$3,259	$1,859	($3,549)	$845	$282	$1,746	$225	$5,070	($11,718)	$9,738	($10,310)
	Commercial & Industrial													
3	Gen. Svc. < 31 kW	23	23	$674	$387	($750)	$159	$57	$330	$34	$125	$0	$1,015	$216
4	Gen. Svc. 31 - 200 kW	28	28	$929	$498	($877)	$279	$100	$598	$60	$7,610	$9,862	$9,197	$10,519
5	Gen. Svc. 201 - 999 kW	30	30	$531	$295	($500)	$179	$64	$372	$38	$3,717	$6,434	$4,696	$6,882
6	Large General Service >= 1,000 kW	48	48	$1,123	$711	($1,209)	$462	$178	$960	$107	($17,725)	$0	($15,394)	$1,209
7	Partial Req. Svc. >= 1,000 kW	47	47	$21	$6	($10)	$4	$1	$8	$1	($150)	$0	($120)	$10
8	Dist. Only Lg Gen Svc >= 1,000 kW	848	848	$10	$0	$0	$0	$0	$0	$0	$0	$0	$10	$0
9	Agricultural Pumping Service	41	41	$137	$92	($184)	$37	$13	$74	$8	($3,822)	($5,896)	($3,645)	($5,856)
10	**Total Commercial & Industrial**			$3,424	$1,989	($3,530)	$1,120	$413	$2,341	$248	($10,245)	$10,399	($4,241)	$12,980
	Lighting													
11	Outdoor Area Lighting Service	15	15	$5	$1	($6)	$0	$0	$0	$0	$74	$186	$74	$181
12	Street Lighting Service Comp. Owned	51	51	$21	$4	($22)	$1	$0	$1	$0	$383	$811	$387	$795
13	Street Lighting Service, Cust Owned	53	53	$5	$2	($4)	$1	$0	$1	$0	$205	$280	$210	$280
14	Recreational Field Lighting	54	54	$1	$0	($1)	$0	$0	$0	$0	$26	$36	$27	$36
15	**Total Public Street Lighting**			$31	$7	($33)	$1	$1	$3	$0	$688	$1,313	$698	$1,292
16	**Subtotal**			$6,715	$3,854	($7,113)	$1,967	$695	$4,090	$474	($4,486)	($6)	$6,196	$3,962
17	Employee Discount			($2)	($1)	$2	($0)	($0)	($1)	($0)	($3)	$7	($6)	$6
18	**Total**			$6,713	$3,853	($7,111)	$1,966	$695	$4,089	$473	($4,489)	$1	$6,190	$3,968

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	Repl Mtr Def Adj 194 ¢/kWh	Tax Act 195 ¢/kWh	Deer Cr Def Adj 198 ¢/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)
				PRE							PRE	PRE	PRE	PRO	PRO	PRO
	Residential															
1	Residential	4	4	0.54%	0.033	(0.063)	0.015	0.005	0.031	0.004	0.090			(0.208)		
	Commercial & Industrial															
2	Gen. Svc. < 31 kW	23	23	0.54%	0.034	(0.066)	0.014	0.005	0.029	0.003	0.011	0.011		0.000	0.000	
3	Gen. Svc. 31 - 200 kW	28	28	0.54%	0.025	(0.044)	0.014	0.005	0.030	0.003	0.382	0.382		0.495	0.495	
4	Gen. Svc. 201 - 999 kW	30	30	0.54%	0.023	(0.039)	0.014	0.005	0.029	0.003	0.290	0.290		0.502	0.502	
5	Large General Service >= 1,000 kW	48	48	0.54%	0.020	(0.034)	0.013	0.005	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%	0.020	(0.034)	0.013	0.005	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%	0.000	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%	0.035	(0.070)	0.014	0.005	0.028	0.003	(1.450)	(1.450)		(2.237)	(2.237)	
	Lighting															
9	Outdoor Area Lighting Service	15	15	0.54%	0.036	(0.077)	0.006	0.004	0.012	0.003	3.520			8.840		
10	Street Lighting Service HPS	51	51	0.54%	0.044	(0.093)	0.006	0.005	0.012	0.003	4.570			9.686		
11	Street Lighting Service	53	53	0.54%	0.017	(0.037)	0.006	0.002	0.012	0.001	1.790			2.447		
12	Recreational Field Lighting	54	54	0.54%	0.023	(0.047)	0.006	0.003	0.012	0.002	2.290			3.135		

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	$23.41	$3.66	18.53%
200	$28.77	$33.59	$4.82	16.75%
300	$37.78	$43.78	$6.00	15.88%
400	$46.80	$53.96	$7.16	15.30%
500	$55.82	$64.15	$8.33	14.92%
600	$64.84	$74.34	$9.50	14.65%
700	$73.86	$84.53	$10.67	14.45%
800	$82.87	$94.72	$11.85	14.30%
900	**$91.89**	**$104.90**	**$13.01**	**14.16%**
1,000	$100.91	$115.09	$14.18	14.05%
1,100	$112.06	$125.98	$13.92	12.42%
1,200	$123.20	$136.86	$13.66	11.09%
1,300	$134.36	$147.75	$13.39	9.97%
1,400	$145.50	$158.63	$13.13	9.02%
1,500	$156.65	$169.52	$12.87	8.22%
1,600	$167.79	$180.41	$12.62	7.52%
2,000	$212.38	$223.95	$11.57	5.45%
3,000	$323.85	$332.81	$8.96	2.77%
4,000	$435.31	$441.67	$6.36	1.46%
5,000	$546.78	$550.53	$3.75	0.69%

* 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	$19.35	$1.13	6.20%
200	$27.24	$29.53	$2.29	8.41%
300	$36.25	$39.72	$3.47	9.57%
400	$45.27	$49.90	$4.63	10.23%
500	$54.29	$60.09	$5.80	10.68%
600	$63.31	$70.28	$6.97	11.01%
700	$72.33	$80.47	$8.14	11.25%
800	$81.34	$90.66	$9.32	11.46%
900	$90.36	$100.84	$10.48	11.60%
1,000	$99.38	$111.03	$11.65	11.72%
1,100	$110.53	$121.92	$11.39	10.30%
1,200	$121.67	$132.80	$11.13	9.15%
1,300	$132.83	$143.69	$10.86	8.18%
1,400	$143.97	$154.57	$10.60	7.36%
1,500	$155.11	$165.46	$10.35	6.67%
1,600	$166.26	$176.35	$10.09	6.07%
2,000	$210.85	$219.89	$9.04	4.29%
3,000	$322.32	$328.75	$6.43	1.99%
4,000	$433.78	$437.61	$3.83	0.88%
5,000	$545.25	$546.47	$1.22	0.22%

* 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	7.33%	6.43%
	750	$93	$102	$101	$109	8.08%	7.34%
	1,000	$118	$127	$128	$137	8.50%	7.88%
	1,500	$169	$177	$184	$192	8.98%	8.50%
10	1,000	$118	$127	$128	$137	8.50%	7.88%
	2,000	$219	$228	$239	$248	9.23%	8.86%
	3,000	$319	$328	$350	$358	9.50%	9.24%
	4,000	$407	$415	$447	$456	9.93%	9.71%
20	4,000	$437	$446	$483	$492	10.50%	10.28%
	6,000	$612	$620	$678	$686	10.78%	10.63%
	8,000	$786	$795	$872	$881	10.95%	10.82%
	10,000	$960	$969	$1,066	$1,075	11.05%	10.94%
30	9,000	$935	$943	$1,042	$1,051	11.46%	11.35%
	12,000	$1,196	$1,205	$1,333	$1,342	11.47%	11.38%
	15,000	$1,458	$1,466	$1,625	$1,634	11.48%	11.41%
	18,000	$1,719	$1,728	$1,917	$1,925	11.48%	11.42%

* 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	7.30%	6.38%
	750	$92	$101	$99	$108	8.05%	7.30%
	1,000	$116	$125	$126	$135	8.49%	7.86%
	1,500	$166	$175	$181	$189	8.97%	8.50%
10	1,000	$116	$125	$126	$135	8.49%	7.86%
	2,000	$215	$224	$235	$244	9.23%	8.85%
	3,000	$314	$323	$344	$353	9.51%	9.23%
	4,000	$400	$408	$439	$448	9.94%	9.72%
20	4,000	$430	$439	$475	$484	10.50%	10.28%
	6,000	$602	$610	$667	$675	10.79%	10.63%
	8,000	$773	$782	$858	$866	10.95%	10.83%
	10,000	$944	$953	$1,049	$1,057	11.06%	10.95%
30	9,000	$920	$928	$1,025	$1,034	11.47%	11.36%
	12,000	$1,177	$1,185	$1,312	$1,321	11.48%	11.39%
	15,000	$1,434	$1,443	$1,598	$1,607	11.49%	11.41%
	18,000	$1,691	$1,700	$1,885	$1,894	11.49%	11.43%

* Net rate including Schedules 91, 290 and 291.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 28 + Cost-Based Supply Service
Large General Service - Secondary Delivery Voltage

kW		Monthly Billing*		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
15	3,000	$328	$328	-0.14%
	4,500	$426	$427	0.19%
	7,500	$621	$624	0.54%
31	6,200	$658	$657	-0.12%
	9,300	$859	$861	0.21%
	15,500	$1,262	$1,269	0.56%
40	8,000	$843	$842	-0.12%
	12,000	$1,103	$1,105	0.21%
	20,000	$1,623	$1,632	0.56%
60	12,000	$1,256	$1,253	-0.20%
	18,000	$1,646	$1,648	0.16%
	30,000	$2,426	$2,439	0.53%
80	16,000	$1,662	$1,659	-0.18%
	24,000	$2,183	$2,186	0.18%
	40,000	$3,223	$3,240	0.54%
100	20,000	$2,069	$2,066	-0.16%
	30,000	$2,719	$2,724	0.19%
	50,000	$4,020	$4,042	0.55%
200	40,000	$4,071	$4,064	-0.16%
	60,000	$5,371	$5,382	0.20%
	100,000	$7,972	$8,017	0.56%

* 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 Load Size	kWh	Monthly Billing* Present Price	Monthly Billing* Proposed Price	Percent Difference
15	4,500	$429	$387	-9.86%
	6,000	$521	$479	-7.97%
	7,500	$612	$571	-6.65%
31	9,300	$860	$781	-9.15%
	12,400	$1,049	$972	-7.34%
	15,500	$1,238	$1,163	-6.08%
40	12,000	$1,102	$1,003	-8.99%
	16,000	$1,346	$1,249	-7.20%
	20,000	$1,590	$1,495	-5.96%
60	18,000	$1,643	$1,497	-8.92%
	24,000	$2,009	$1,866	-7.13%
	30,000	$2,375	$2,235	-5.90%
80	24,000	$2,176	$1,986	-8.77%
	32,000	$2,664	$2,478	-7.00%
	40,000	$3,152	$2,970	-5.78%
100	30,000	$2,710	$2,474	-8.68%
	40,000	$3,320	$3,090	-6.93%
	50,000	$3,930	$3,705	-5.71%
200	60,000	$5,342	$4,898	-8.31%
	80,000	$6,562	$6,129	-6.60%
	100,000	$7,782	$7,359	-5.43%

* 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		Monthly Billing*		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
100	20,000	$2,505	$2,543	1.53%
	30,000	$2,990	$2,981	-0.28%
	50,000	$3,960	$3,858	-2.58%
200	40,000	$4,505	$4,642	3.02%
	60,000	$5,475	$5,518	0.78%
	100,000	$7,415	$7,271	-1.95%
300	60,000	$6,685	$6,897	3.18%
	90,000	$8,140	$8,212	0.89%
	150,000	$11,050	$10,841	-1.89%
400	80,000	$8,737	$9,043	3.49%
	120,000	$10,677	$10,796	1.11%
	200,000	$14,557	$14,301	-1.76%
500	100,000	$10,825	$11,217	3.62%
	150,000	$13,250	$13,408	1.20%
	250,000	$18,100	$17,791	-1.71%
600	120,000	$12,912	$13,392	3.71%
	180,000	$15,822	$16,021	1.26%
	300,000	$21,642	$21,280	-1.67%
800	160,000	$17,087	$17,741	3.83%
	240,000	$20,967	$21,247	1.33%
	400,000	$28,727	$28,258	-1.63%
1000	200,000	$21,262	$22,090	3.90%
	300,000	$26,112	$26,473	1.38%
	500,000	$35,792	$35,217	-1.61%

* 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		Monthly Billing*		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
100	30,000	$2,979	$2,941	-1.26%
	40,000	$3,465	$3,379	-2.48%
	50,000	$3,952	$3,817	-3.40%
200	60,000	$5,467	$5,466	-0.01%
	80,000	$6,440	$6,342	-1.51%
	100,000	$7,412	$7,218	-2.62%
300	90,000	$8,123	$8,133	0.12%
	120,000	$9,582	$9,447	-1.41%
	150,000	$11,042	$10,761	-2.54%
400	120,000	$10,679	$10,727	0.45%
	160,000	$12,625	$12,479	-1.16%
	200,000	$14,571	$14,231	-2.33%
500	150,000	$13,249	$13,323	0.56%
	200,000	$15,681	$15,513	-1.07%
	250,000	$18,113	$17,703	-2.26%
600	180,000	$15,818	$15,919	0.64%
	240,000	$18,737	$18,547	-1.01%
	300,000	$21,656	$21,175	-2.22%
800	240,000	$20,958	$21,111	0.73%
	320,000	$24,849	$24,615	-0.94%
	400,000	$28,740	$28,119	-2.16%
1000	300,000	$26,097	$26,303	0.79%
	400,000	$30,961	$30,683	-0.90%
	500,000	$35,805	$35,044	-2.13%

* 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	$185	$174	15.08%	-0.53%
	3,000	$241	$175	$277	$174	15.08%	-0.53%
	5,000	$402	$175	$462	$174	15.08%	-0.53%
Three Phase							
20	4,000	$321	$349	$370	$347	15.08%	-0.54%
	6,000	$482	$349	$555	$347	15.08%	-0.54%
	10,000	$803	$349	$924	$347	15.08%	-0.54%
100	20,000	$1,607	$1,561	$1,849	$1,685	15.08%	7.91%
	30,000	$2,410	$1,561	$2,773	$1,685	15.08%	7.91%
	50,000	$4,016	$1,561	$4,622	$1,685	15.08%	7.91%
300	60,000	$4,820	$3,929	$5,546	$4,061	15.08%	3.36%
	90,000	$7,229	$3,929	$8,319	$4,061	15.08%	3.36%
	150,000	$12,049	$3,929	$13,865	$4,061	15.08%	3.36%

* 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	$272	$172	15.00%	-0.53%
	4,000	$315	$172	$362	$172	14.99%	-0.53%
	5,000	$394	$172	$453	$172	14.99%	-0.53%
Three Phase							
20	6,000	$473	$345	$544	$343	14.99%	-0.54%
	8,000	$630	$345	$725	$343	14.99%	-0.54%
	10,000	$788	$345	$906	$343	14.99%	-0.54%
100	30,000	$2,364	$1,541	$2,719	$1,654	14.99%	7.37%
	40,000	$3,152	$1,541	$3,625	$1,654	14.99%	7.37%
	50,000	$3,940	$1,541	$4,531	$1,654	14.99%	7.37%
300	90,000	$7,092	$3,868	$8,156	$3,990	14.99%	3.15%
	120,000	$9,457	$3,868	$10,874	$3,990	14.99%	3.15%
	150,000	$11,821	$3,868	$13,593	$3,990	14.99%	3.15%

* 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 Load Size	kWh	Monthly Billing		Percent Difference
		Present Price	Proposed Price	
1,000	300,000	$25,940	$26,489	2.12%
	500,000	$35,159	$36,455	3.69%
	700,000	$44,190	$46,234	4.63%
2,000	600,000	$51,165	$52,306	2.23%
	1,000,000	$67,127	$69,815	4.00%
	1,400,000	$84,164	$88,376	5.01%
6,000	1,800,000	$137,264	$139,288	1.47%
	3,000,000	$188,374	$194,971	3.50%
	4,200,000	$239,484	$250,655	4.66%
12,000	3,600,000	$272,363	$276,524	1.53%
	6,000,000	$374,583	$387,890	3.55%
	8,400,000	$476,804	$499,257	4.71%

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 Load Size	kWh	Monthly Billing Present Price	Monthly Billing Proposed Price	Percent Difference
1,000	300,000	$24,192	$24,846	2.71%
	500,000	$32,897	$34,516	4.92%
	700,000	$41,415	$43,997	6.23%
2,000	600,000	$47,698	$49,031	2.79%
	1,000,000	$62,546	$65,870	5.31%
	1,400,000	$78,538	$83,826	6.73%
6,000	1,800,000	$135,690	$140,135	3.28%
	3,000,000	$183,663	$194,002	5.63%
	4,200,000	$231,637	$247,869	7.01%
12,000	3,600,000	$269,330	$278,248	3.31%
	6,000,000	$365,277	$385,982	5.67%
	8,400,000	$461,223	$493,717	7.05%

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	$33,004	6.21%
	700,000	$39,017	$42,181	8.11%
2,000	1,000,000	$58,661	$62,602	6.72%
	1,400,000	$73,480	$79,937	8.79%
6,000	3,000,000	$173,411	$185,242	6.82%
	4,200,000	$217,870	$237,249	8.89%
12,000	6,000,000	$344,428	$368,101	6.87%
	8,400,000	$433,347	$472,115	8.95%

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/1111
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Residential Basic Charge Calculation

March 2022

Residential Basic Charge Calculation
20 Year Residential Marginal Unit Costs
December 2023 Dollars per Customer per Year

	All Residential	Single Family	Multi-Family
Poles	$78.70	$88.87	$32.71
Conductor	$39.08	$44.12	$16.25
Transformers	$85.45	$104.17	$29.11
Service Drop	$75.76	$75.76	$75.76
Meters	$23.21	$23.21	$23.21
Meter Reading	$0.00	$0.00	$0.00
Billing & Collections	$25.10	$25.10	$25.10
Uncollectables	$9.64	$9.64	$9.64
Customer Service / Other	$9.26	$9.26	$9.26
Total per Year	$346.20	$380.14	$221.03
Total per Month	$28.85	**$31.68**	**$18.42**
Current Basic Charge		$9.50	$8.00
Proposed Basic Charge		**$12.00**	**$8.00**