PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah Street, Suite 2000
Portland, Oregon 97232

February 14, 2024

VIA ELECTRONIC FILING

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

Re: Advice No. 24-001/Docket UE 433—PacifiCorp's Request for General Rate Revision

PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company) submits for filing 17 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, 2025. Electronic versions of the testimony, exhibits, supporting workpapers, and copies of the Company's responses to the Standard Data Requests are being uploaded to Huddle.

Sheet	Schedule	Title
Seventh Revision of Sheet No. INDEX-2		Table of Contents – Schedules
Thirty-fourth Revision of Sheet No. INDEX-3		Table of Contents – Schedules
Fifth Revision of Sheet No. 4-1	Schedule 4	Residential Service Delivery Service
First Revision of Sheet No. 4-1	Schedule 4	Residential Service Delivery Service
Fifth Revision of Sheet No. 5-1	Schedule 5	Separately Metered Electric Vehicle Service for Residential Consumers Delivery Service
Original Sheet No. 5-2	Schedule 5	Separately Metered Electric Vehicle Service for Residential Consumers Delivery Service
CANCELED First Revision of Sheet No. 6-1	Schedule 6	Pilot for Residential Time-of-Use Service Delivery Service
CANCELED Original Sheet No. 6-2	Schedule 6	Pilot for Residential Time-of-Use Service Delivery Service
Second Revision of Sheet No. 7-1	Schedule 7	Low-Income Discount
Sixth Revision of Sheet No. 15-1	Schedule 15	Outdoor Area Lighting Service – Delivery Service
Sixth Revision of Sheet No. 23-1	Schedule 23	General Service – Small Nonresidential Delivery Service
Fourth Revision of Sheet No. 23-2	Schedule 23	General Service – Small Nonresidential Delivery Service
Second Revision of Sheet No. 23-3	Schedule 23	General Service – Small Nonresidential Delivery Service
Fifth Revision of Sheet No. 28-1	Schedule 28	General Service Large Nonresidential 31KW to 200 KW Delivery Service
Second Revision of Sheet No. 29-1	Schedule 29	General Service Time-Of-Use Large Nonresidential Delivery Service

Sheet	Schedule	Title
First Revision of Sheet No. 29-2	Schedule 29	General Service Time-Of-Use Large Nonresidential Delivery Service
Fifth Revision of Sheet No. 30-1	Schedule 30	General Service Large Nonresidential 201 KW to 999 KW Delivery Service
Fifth Revision of Sheet No. 41-1	Schedule 41	Agricultural Pumping Service Delivery Service
Fourth Revision of Sheet No. 41-2	Schedule 41	Agricultural Pumping Service Delivery Service
Third Revision of Sheet No. 41-3	Schedule 41	Agricultural Pumping Service Delivery Service
Fifth Revision of Sheet No. 47-1	Schedule 47	Large General Service Partial Requirements 1,000 KW and Over Delivery Service
Fourth Revision of Sheet No. 47-2	Schedule 47	Large General Service Partial Requirements 1,000 KW and Over Delivery Service
Sixth Revision of Sheet No. 48-1	Schedule 48	Large General Service 1,000 KW and Over Delivery Service
Sixth Revision of Sheet No. 48-2	Schedule 48	Large General Service 1,000 KW and Over Delivery Service
Sixth Revision of Sheet No. 51-1	Schedule 51	Street Lighting Service Company – Owned System Delivery Service
Sixth Revision of Sheet No. 53-1	Schedule 53	Street Lighting Service Consumer – Owned System Delivery Service
Sixth Revision of Sheet No. 54-1	Schedule 54	Recreational Field Lighting – Restricted Delivery Service
Fifth Revision of Sheet No. 76R-1	Schedule 76R	Large General Service – Partial Requirements Service Economic Replacement Power Rider Delivery Service
Original Sheet No. 80	Schedule 80	Insurance Cost Adjustment
Thirty-third Revision of Sheet No. 90-1	Schedule 90	Summary of Effective Rate Adjustments
Second Revision of Sheet No. 90-2	Schedule 90	Summary of Effective Rate Adjustments
Fourteenth Revision of Sheet No. 91-1	Schedule 91	Low Income Bill Payment Assistance Fund
First Revision of Sheet No. 92-1	Schedule 92	Low-Income Discount Cost Recovery Adjustment
Sixteenth Revision of Sheet No. 98	Schedule 98	Adjustment Associated with the Pacific Northwest Electric Power Planning and Conservation Act
Second Revision of Sheet No. 117-2	Schedule 117	Transportation Electrification Residential Charging Pilot
Second Revision of Sheet No. 118-2	Schedule 118	Transportation Electrification Nonresidential and Multifamily-Unit Dwelling Charging Pilot

Sheet	**Schedule**	**Title**
Original Sheet No. 193	Schedule 193	Catastrophic Fire Fund Adjustment
Ninth Revision of Sheet No. 200-1	Schedule 200	Base Supply Service
Ninth Revision of Sheet No. 200-2	Schedule 200	Base Supply Service
Ninth Revision of Sheet No. 200-3	Schedule 200	Base Supply Service
Nineteenth Revision of Sheet No. 201-1	Schedule 201	Net Power Cost-Based Supply Service
Nineteenth Revision of Sheet No. 201-2	Schedule 201	Net Power Cost-Based Supply Service
CANCELED Tenth Revision of Sheet No. 205-1	Schedule 205	TAM Adjustment for Other Revenues
CANCELED Tenth Revision of Sheet No. 205-2	Schedule 205	TAM Adjustment for Other Revenues
CANCELED Tenth Revision of Sheet No. 205-3	Schedule 205	TAM Adjustment for Other Revenues
Fifth Revision of Sheet No. 210-1	Schedule 210	Portfolio Time-Of-Use Supply Service Closed to New Service
Fifth Revision of Sheet No. 210-2	Schedule 210	Portfolio Time-Of-Use Supply Service Closed to New Service
Fourth Revision of Sheet No. 293-1	Schedule 293	New Large Load Direct Access Program Cost of Service Opt-Out
Fifth Revision of Sheet No. 299	Schedule 299	Rate Mitigation Adjustment
Fourth Revision of Sheet No. 300-3	Schedule 300	Charges as Defined by the Rules and Regulations
Fifth Revision of Sheet No. 723-1	Schedule 723	General Service – Small Nonresidential Direct Access Delivery Service
Fifth Revision of Sheet No. 728-1	Schedule 728	General Service Large Nonresidential 31 KW to 200 KW Direct Access Delivery Service
Fifth Revision of Sheet No. 730-1	Schedule 730	General Service Large Nonresidential 201 KW to 999 KW Direct Access Delivery Service
Fifth Revision of Sheet No.741-1	Schedule 741	Agricultural Pumping Service Direct Access Delivery Service
Fifth Revision of Sheet No. 747-1	Schedule 747	Large General Service Partial Requirements 1,000 KW and Over Direct Access Delivery Service
Fourth Revision of Sheet No. 747-2	Schedule 747	Large General Service Partial Requirements 1,000 KW and Over Direct Access Delivery Service
Sixth Revision of Sheet No. 748-1	Schedule 748	Large General Service 1,000 KW and Over Direct Access Delivery Service
Sixth Revision of Sheet No. 748-2	Schedule 748	Large General Service 1,000 KW and Over Direct Access Delivery Service
Sixth Revision of Sheet No. 751-1	Schedule 751	Street Lighting Service Company-Owned System Direct Access Delivery Service

Sheet	**Schedule**	**Title**
Sixth Revision of Sheet No. 753-1	Schedule 753	Street Lighting Service Consumer-Owned System Direct Access Delivery Service
Sixth Revision of Sheet No. 754	Schedule 754	Recreational Field Lighting–Restricted Direct Access Delivery Service
Fifth Revision of Sheet No. 776R-1	Schedule 776R	Large General Service-Partial Requirements Service-Economic Replacement Service Rider Direct Access Delivery Service
Third 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. 848-2	Schedule 848	Large General Service 1,000 KW and Over Direct Access Delivery Service – Distribution Only
Third Revision of Sheet No. R1-2	Rule 1	General Rules and Regulations Definitions
Third Revision of Sheet No. R13-1	Rule 13	General Rules and Regulations Line Extensions
Fourth Revision of Sheet No. R13-2	Rule 13	General Rules and Regulations Line Extensions
Third Revision of Sheet No. R13-3	Rule 13	General Rules and Regulations Line Extensions
Third Revision of Sheet No. R13-4	Rule 13	General Rules and Regulations Line Extensions
Third Revision of Sheet No. R13-5	Rule 13	General Rules and Regulations Line Extensions
Seventh Revision of Sheet No. R13-6	Rule 13	General Rules and Regulations Line Extensions
Fifth Revision of Sheet No. R13-7	Rule 13	General Rules and Regulations Line Extensions
Fifth Revision of Sheet No. R13-8	Rule 13	General Rules and Regulations Line Extensions
Fifth Revision of Sheet No. R13-9	Rule 13	General Rules and Regulations Line Extensions
Fourth Revision of Sheet No. R13-10	Rule 13	General Rules and Regulations Line Extensions
Fourth Revision of Sheet No. R13-11	Rule 13	General Rules and Regulations Line Extensions
Fifth Revision of Sheet No. R13-12	Rule 13	General Rules and Regulations Line Extensions
Third Revision of Sheet No. R13-13	Rule 13	General Rules and Regulations Line Extensions
Original Sheet No. R13-14	Rule 13	General Rules and Regulations Line Extensions
Original Sheet No. R13-15	Rule 13	General Rules and Regulations Line Extensions

Confidential material in support of the filing has been provided to parties who have signed General Protective Order No. 23-132 for this docket.

Please address all communications related to this filing to:

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

Sincerely,

Matthew McVee
Vice President, Regulatory Policy and Operations

Enclosures

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 433

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) respectfully requests the Public Utility Commission of Oregon revise the Company's schedules of rates and charges for Oregon electric services under ORS 757.205 and 757.220.

PacifiCorp is requesting an overall increase in rates of approximately $322.3 million or 17.9 percent.[1] This overall request is comprised of (1) a base rate increase of $157.7 million; (2) an Insurance Cost Adjustment of $66.0 million, which reflects both deferred and on-going insurance premiums; (3) $77.7 million to fund the Company's proposed Catastrophic Fire Fund; (4) the estimated true-up of $21.2 million for the Wildfire Mitigation Plan (WMP) automatic adjustment clause (AAC); and (5) the rebalancing of the Rate Mitigation Adjustment for a reduction of $0.4 million.

This general rate revision is necessary because the Company is currently forecasted to earn a normalized return on equity (ROE) in Oregon of 6.5 percent under current rates, which is less than the Company's currently authorized ROE of 9.5 percent. The Company's proposed rates would produce revenues that are necessary to sustain a stable, reliable, and

[1] When combined with a proposed $18.3 million decrease in net power costs in docket UE 434, the overall change results in a net base rate increase of $304.1 million. *See, In the Matter of PacifiCorp. dba Pacific Power, 2025 Transition Adjustment Mechanism,* Docket No. UE 434, filed Feb. 14, 2024.

low-cost power supply, while also preserving the Company's ability to attract capital for future investments.

PacifiCorp is an electric company and public utility in Oregon within the meaning of ORS 757.005, and is subject to Commission jurisdiction regarding PacifiCorp's prices and terms of electric service for Oregon retail customers. The Company provides electric service to approximately 627,000 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. This executive summary and the attached Exhibit A are filed in compliance with OAR 860-022-0019.

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

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

II. CASE SUMMARY

The Company is requesting an overall increase in rates of approximately $322.3 million for rates effective January 1, 2025, and if approved, would result in an $1,234.2 million non-net power cost revenue requirement. This revenue requirement is based on a historical base period of 12 months that ended June 2023, and normalizing and pro forma adjustments to calculate a calendar year 2025 future test period (with the exception of capital additions that are based on calendar year-end 2024 balances). The new rates assume a full nine-month statutory suspension period, in addition to the 30-day effective date now contained in tariffs. The following briefly summarizes the Company's Weighted Average Cost of Capital (WACC), Cost Drivers, Rate Design, and Modification to Existing Regulatory Mechanisms.

A. Weighted Average Cost of Capital

The Company is requesting an overall WACC of 7.74 percent. This is based on an increased ROE to 10.30 percent from the currently authorized 9.5 percent, a cost of preferred stock of 6.75 percent, and a cost of long-term debt of 5.18 percent. The Company also proposes a capital structure that includes 50.00 percent common stock, 49.99 percent long-term debt, and 0.01 percent preferred stock.

This proposed WACC 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

This rate request includes several cost drivers, including new capital additions and increased operating and maintenance expenses.

i. Capital Additions

The Company continues to make new investments in its system that are 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 Company's system—including transmission, generation, distribution, and customer support assets—to bolster reliability and improve power delivery and customer services.

These investments include over 600 miles of new high voltage transmission lines and related network upgrades and supporting transmission and distribution infrastructure; 240 megawatts of new and repowered wind generation facilities; the conversion of 1.2 gigawatts of existing coal generation to operate on natural gas; a substantial modernization of the Company's customer service system to improve the delivery and support of various customer services; and material wildfire mitigation investments.

ii. Operating and Maintenance Costs

PacifiCorp is requesting recovery of increased operating and maintenance costs for several categories of costs. These include material increases to insurance premiums that have been caused by increased wildfire liability risks in the region generally, and for the Company specifically. PacifiCorp is requesting approval of two mechanisms, the Insurance Cost

Adjustment and Catastrophic Fire Fund, that are outside of base rates to address the escalating costs of wildfire liability. This increase also includes costs resulting from rebuild and restoration of PacifiCorp infrastructure caused by wildfires from 2020.

Further, unrelated to wildfire mitigation measures, the Company is incurring additional spending with respect to vegetation management as a result of increasing costs. The Company's rate revision includes these increased levels of vegetation management costs to base rates.

C. Rate Design

The Company is proposing a rate spread that is consistent with the cost-of-service study and Rate Mitigation Adjustment, where no customer rate class will see an increase greater than 22.4 percent. PacifiCorp proposes an average 17.9 percent increase to current rates.

PacifiCorp also proposes to increase the single-family basic charge from $11 to $16 per month, the multi-family basic charge from $8 to $9. For large non-residential customers, the Company proposes a Customer-Funded Substation Credit for certain large customers that did not receive a line extension allowance greater than the cost of metering and a Capacity Reservation Charge and Excess Demand Charge that would be applicable to large customers who reserve more power than they require or use more than the level for which they contracted. PacifiCorp also proposes improvements and consolidation of its time-of-use options.

D. Proposed Regulatory Mechanisms

The Company requests approval of two proposals that will help position the Company to respond to financial risk posed by the increasing frequency and severity of wildfires impacting PacifiCorp's service areas.

The first is an Insurance Cost Adjustment that enable the Company to annually procure insurance for third-party liability using the most economical combination of commercial insurance and insurance through a new Insurance Mechanism. Specific to this general rate case, the Company is seeking approval to recover liability insurance costs through a surcharge.

The second mechanism is a Catastrophic Fire Fund that will facilitate a multi-state risk pool for potential catastrophic events where third-party liabilities are in excess of the Company's insurance coverage.

These proposals complement the Company's ongoing investments in wildfire mitigation throughout its service territory, and are required by the rapid changes in the insurance market and the wildfire liability outlook for utilities throughout the West.

III. TESTIMONY SUMMARY

The Company's general rate revision is supported by the following testimony and exhibits of 19 PacifiCorp witnesses or third-party expert consultants:

- **Cindy A. Crane**, Chief Executive Officer, provides an overview of PacifiCorp, its Oregon service area, and the strategies the Company is pursuing to provide Oregon customers with low-cost, reliable, and non-emitting generation to power their homes, businesses, and communities. She also explains the escalating wildfire risk that the Company has faced since its last rate case, the steps the Company is taking to address those risks, and introduces the Company witnesses that provide direct testimony in support of PacifiCorp's rate request.
- **Matthew D. McVee**, Vice President, Regulatory Policy and Operations, describes

PacifiCorp's request in this proceeding and summarize the regulatory policies of the Company. He also explains the steps the Company is taking to incorporate equity in its Oregon operations and planning.

- **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.
- **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.
- **Robert S. Mudge,** Principal at The Brattle Group, discusses the increased wildfire risk and financial exposure faced by utilities in the Western U.S. and explains how PacifiCorp's proposed remedies are reasonable to manage this growing risk.
- **Joelle R. Steward**, Senior Vice President, Regulation and Customer/Community Solutions, supports an Insurance Cost Adjustment that will support a new insurance mechanism in development and a Catastrophic Fire Fund.
- **Mariya V. Coleman**, Vice President of Corporate Insurance and Claims for Berkshire Hathaway Energy Company, supports the Company's updated costs associated with insurance premiums.
- **Rick T. Link**, Senior Vice President, Resource Planning, Procurement and Optimization, provides the economic analyses of the Gateway South and Gateway West Segment D.1 transmission projects.
- **Thomas R. Burns**, Vice President of Resource Planning and Acquisitions for PacifiCorp, provides the economic analyses of the conversion of Jim Bridger Units 1

and 2 to natural gas, the Rock Creek I wind facility, and the Rock River I repowering project.

- **Richard A. Vail**, Vice President of Transmission Services, describes PacifiCorp's transmission system and the benefits it provides to Oregon customers, and discusses important transmission and distribution system upgrades that will be completed to serve customers, including the Gateway South and Gateway West Segment D.1 transmission projects.
- **Timothy J. Hemstreet**, Vice President of Renewable Energy Development, supports the Company's Rock River I repowering project and its investment in the Fall Creek Hatchery.
- **Jeffrey M. Wagner**, Renewable Development Manager, provides support of the prudency of the Rock Creek I wind project.
- **Brad D. Richards**, Vice President of Thermal Generation, supports the Company's investment in the gas conversion of Jim Bridger Units 1 and 2 and the flue gas desulfurization pond project at the Jim Bridger Plant.
- **Allen Berreth**, Vice President of Transmission and Distribution Operations, supports the wildfire-related transmission and distribution investments and vegetation management expenses in the rate case. He also supports the inclusion of the restoration costs related to the September 2020 wildfires. Finally, he supports the Company's investment in the Juniper Ridge Bend Service Center.
- **William J. Comeau**, Vice President of Customer Experience and Innovation, supports the upgrade to the Company's legacy Customer Service System.

- **Kenneth Lee Elder, Jr.**, Load Forecasting Manager, supports the Company's load forecast for the test period.
- **Sherona L. Cheung**, Revenue Requirement Manager, summarizes the overall test year revenue requirement, pro forma adjustments, and the rate base calculation methodology.
- **Anna DeMers**, Senior Customer Regulatory Specialist, supports several new proposed policies in response to very large customers, including a Capacity Reservation Charge and an Excess Demand Charge, in addition to extending the period during which very large customers are eligible for Line Extension Refunds.
- **Robert M. Meredith**, Director of Pricing and Tariff Policy, provides PacifiCorp's cost of service study and rate design, and discusses how the proposed tariff changes recover the proposed revenue requirement to achieve fair, just, and reasonable prices for customers.

IV. CONCLUSION

The Company respectfully requests the Commission approve PacifiCorp's proposed general rate revisions and tariff amendments.

Respectfully submitted February 14, 2024.

Carla Scarsella

Carla Scarsella
Deputy General Counsel
Ajay Kumar
Assistant General Counsel

PacifiCorp d/b/a Pacific Power

EXHIBIT A

Exhibit A
Summary of Requested Electric General Rate Increase
Oregon Allocated
Filed February 14, 2024

(A)	Total net revenues collected under proposed rates:	$2,120,636,823
(B)	**Base**[1]	
	Revenue change requested:	
	Total:	$208,106,240
	Net of credits from federal agencies:	$208,106,240
	Net[2]	
	Revenue change requested:	
	Total:	$322,337,401
	Net of credits from federal agencies:	$322,337,401
(C)	**Base**[1]	
	Percentage change in revenues requested:	
	Total %:	12.4%
	Net of credits from federal agencies:	12.4%
	Net[2]	
	Percentage change in revenues requested:	
	Total %:	17.9%
	Net of credits from federal agencies:	17.9%
(D)	Test period:	Calendar year 2025
(E)	Requested return on capital:	7.74%
	Requested return on equity:	10.3%
(F)	Rate base proposed in filing:	$5,300,883,073
(G)	Results of operation:	
	Utility operating income, before proposed change:	$308,794,389
	Utility operating income, after proposed change:	$410,296,672

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

	Base Change[1]	Net Change[2]
• Residential:	12.5%	21.6%
• Small General Service (Schedule 23):	15.8%	22.4%
• General Service 31-200 kW (Schedule 28):	9.2%	10.4%
• General Service 201-999 kW (Schedule 30):	11.5%	11.3%
• Large General Service >= 1,000 kW (Schedule 48):	11.3%	14.1%
• Agriculture Pumping Service (Schedule 41):	21.9%	22.4%
• Street lighting:	11.4%	4.5%
• Total	12.4%	17.9%

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

[1] Base change includes $50.4 million for the proposed base Insurance Cost Adjustment as discussed in the application and testimony.
[2] Net Change reflects the net impact to customers on January 1, 2025, of the proposed price change including $15.6 million for the deferred Insurance Cost Adjustment, $77.7 million for the Catastrophic Fire Fund, $21.2 million for the true-up of the Wildfire Mitigation Plan automatic adjustment clause and a reduction of $0.4 million for the rebalancing of the Rate Mitigation Adjustment as discussed in the application and testimony.

ACRONYM LIST

Witness	Acronym	Definition
Crane	CEO	Chief Executive Officer
Crane	U.S.	Western United States
Crane	2023 Rate Case	last general rate case
Comeau	Company	PacifiCorp d/b/a Pacific Power
Comeau	CSS	Company's legacy Customer Service System
Comeau	BHE	Berkshire Hathaway Energy
Comeau	IT	information technology
Wagner	MW	megawatt
Wagner	Rock Creek I	Rock Creek I Wind Project
Wagner	IRP	integrated resource plan
Wagner	2020AS RFP	2020 All-Source Request for Proposal
Wagner	BTA	build-transfer agreement
Wagner	WTG	wind turbine generator
Wagner	CPCN	certificate of public convenience and necessity
Wagner	Wyoming Commission	Wyoming Public Service Commission
Wagner	PTC	production tax credit
Wagner	O&M	operations and maintenance
Wagner	IRA	Inflation Reduction Act
Bulkley	Brattle	The Brattle Group
Bulkley	Commission	Public Utility Commission of Oregon
Bulkley	BHE	Berkshire Hathaway Energy Company
Bulkley	ROE	Return on Equity
Bulkley	DCF	Discounted Cash Flow
Bulkley	CAPM	Capital Asset Pricing Model
Bulkley	ECAPM	Empirical Capital Asset Pricing Model
Bulkley	BYRP or Risk Premium	Bond Yield Risk Premium
Bulkley	2020 GRC	2020 general rate case
Bulkley	PNW	Pinnacle West Capital Corporation
Bulkley	ICC	Illinois Commerce Commission
Bulkley	Ameren IL	Ameren Illinois Co.
Bulkley	ComEd	Commonwealth Edison Co.
Bulkley	RRA	Regulatory Research Associates
Bulkley	YOY	year-over-year
Bulkley	CPI	Consumer Price Index
Bulkley	FOMC	Federal Open Market Committee
Bulkley	SEP	Summary of Economic Projections
Bulkley	S&P	Standard and Poor's
Bulkley	EPS	earnings per share
Bulkley	GDP	gross domestic product
Bulkley	EIA	Energy Information Administration
Bulkley	U.S.	United States
Bulkley	BofA	BofA Securities
Bulkley	PG&E	Pacific Gas and Electric Company
Bulkley	SoCalEd	Southern California Edison
Bulkley	FEMA	Federal Emergency Management Agency
Bulkley	PCAM	Power Cost Adjustment Mechanism
Bulkley	Fitch	Fitch Ratings

Hemstreet	PTC	production tax credit
Hemstreet	FERC	Federal Energy Regulatory Commission
Hemstreet	KHSA	Klamath Hydroelectric Settlement Agreement
Hemstreet	CDFW	California Department of Fish and Wildlife
Hemstreet	NMFS	National Marine Fisheries Service
Hemstreet	MW	megawatt
Hemstreet	WTG	wind turbine generator
Hemstreet	U.S.	United States
Hemstreet	PSOA	Purchase and Sale Option Agreement
Hemstreet	GE	General Electric International, Inc.
Hemstreet	Black & Veatch	Black & Veatch, Inc.
Hemstreet	KRRC	Klamath River Renewal Corporation
Burns	IRP	integrated resource plan
Burns	MW	megawatt
Burns	PVRR(d)	present-value revenue requirement differential
Burns	IRA	Inflation Reduction Act
Burns	RECs	renewable energy certificates
Burns	CO_2	carbon dioxide
Burns	LT	Long-term platform of the PLEXOS modeling system
Burns	MT	Medium-term platform of the PLEXOS modeling system
Burns	ST	Short-term platform of the PLEXOS modeling system
Burns	2020AS RFP	2020 All-Source Request for Proposals
Burns	MM	medium natural gas prices paired with medium CO2 prices
Burns	LN	low natural gas prices without a CO2 price
Burns	MN	medium natural gas prices without a CO2 price
Burns	HH	high natural gas prices paired with high CO2 prices
Burns	SCGHG	medium gas prices and the social cost of greenhouse gases
Burns	NPC	net power cost
Burns	OFPC	official forward price curve
Burns	OTR	Ozone Transport Rule
Burns	NO_X	nitrogen oxide
Burns	BTA	build-transfer agreement
Burns	PTC	production tax credit
Burns	NERC	North American Electric Reliability Corporation
Burns	EPA	Environmental Protection Agency
Burns	SCR	selective catalytic reduction
Burns	PVRR	present-value revenue requirement
Burns	WTG	wind turbine generator
Link	IRP	integrated resource plan
Link	RFP	request for proposal
Link	Commission	Public Utility Commission of Oregon
Link	Utah Commission	Utah Public Service Commission
Link	kV	kilovolt
Link	Transmission Projects	Gateway South and Gateway West Segment D.1 transmission projects
Link	2020AS RFP	2020 All-Source Request for Proposal
Link	PTC	production tax credits
Link	RECs	renewable-energy credits
Link	megawatts	MW
Link	PTP	point-to-point
Link	FERC	Federal Energy Regulatory Commission
Link	CO_2	carbon dioxide
Link	price-policy scenarios	five different scenarios that pair varying natural gas price assumptions with varying carbon dioxide policy assumptions
Link	MM	Medium natural gas prices paired with medium CO_2 prices
Link	MN	Medium natural gas prices without a CO_2 price
Link	HH	High natural gas prices paired with high CO_2 prices
Link	LN	Low natural gas prices without a CO_2 price
Link	SCGHG	The Social Cost of Greenhouse Gas
Link	PVRR(d)	present-value revenue requirement differential
Link	IRA	Inflation Reduction Act
Link	OTR	Ozone Transport Rule

Link	WECC	Western Electricity Coordinating Council
Link	WARA	Western Assessment of Resource Adequacy Report
Link	NWPP-NW	Northwest Power Pool Northwest
Link	NWPP-NE	Northwest Power Pool Northeast
Link	NWPP-C	Northwest Power Pool Central
Link	NERC	North American Electric Reliability Corporation
Link	LTRA	Long-Term Resource Adequacy
Link	BESS	battery energy storage systems
Link	PPA	power-purchase agreements
Link	BTA	build-transfer agreements
Link	BSA	battery storage agreements
Link	NPC	net-power costs
Link	OFPC	official forward price curve
Link	EPA	Environmental Protection Agency
Link	LT	Long-term platform of the PLEXOS modeling system
Link	MT	Medium-term platform of the PLEXOS modeling system
Link	ST	Short-term platform of the PLEXOS modeling system
Link	DSM	demand-side management
Link	Aurora	AURORAXMP4
Elder	kWh	kilowatt-hour
Elder	Rate Case	general rate case
Elder	MWh	megawatt-hour
Elder	Test Period	12-month period ending December 31, 2025
Elder	CY 2025	2025 Rate Case
Elder	LED	light-emitting diode
Elder	RBM	regional business manager
Berreth	WMP	Mitigation Plan
Berreth	AAC	Automatic Adjustment Clause
Berreth	Commission	Public Utilities Commission of Oregon
Berreth	SB	Senate Bill
Berreth	O&M	operation and maintenance
Berreth	WMVM	Wildfire Mitigation and Vegetation Management
Richards	FGD	flue gas desulfurization
Richards	O&M	operating and maintenance

Vail	OATT	Open Access Transmission Tariff
Vail	GWS	Gateway South
Vail	kV	kilovolt
Vail	Commission	Public Utility Commission of Oregon
Vail	BAA	balancing authority area
Vail	CAISO	California Independent System Operation
Vail	WEIM	Western Energy Imbalance Market
Vail	PACE	PacifiCorp East
Vail	PACW	PacifiCorp West
Vail	BPA	Bonneville Power Administration
Vail	FERC	Federal Energy Regulatory Commission
Vail	BES	Bulk Electric System
Vail	NERC	North American Electric Reliability Corporation
Vail	TPL Standards	transmission system planning performance requirements
Vail	WECC	Western Electricity Coordinating Council
Vail	ATRR	annual transmission revenue requirement
Vail	Transmission Projects	Gateway South and Gateway West Transmission Projects
Vail	MW	megawatt
Vail	ROW	right-of-way
Vail	MVA	megavolt amperes
Vail	RAS	remedial action scheme
Vail	EMS	Energy Management System
Vail	FVC	Fast Volt Controller
Vail	WFS	Wasatch Front South
Cheung	NPC	net power costs
Cheung	GRC	general rate case
Cheung	TAM	Transition Adjustment Mechanism
Cheung	Base Period	historical period of the 12 months ended June 2023
Cheung	Test Period	12-month period ending December 31, 2025
Cheung	ROE	return on equity
Cheung	WMP	Wildfire Mitigation Plan
Cheung	AAC	Automatic Adjustment Clause
Cheung	2023 Rate Case	the Company's 2023 GRC, docket UE 399
Cheung	2020 Protocol	2020 PacifiCorp Inter-Jurisdictional Allocation Protocol
Cheung	ECD	embedded cost differential
Cheung	O&M	operations and maintenance
Cheung	ADV 1529 Agreement	agreement reached in docket ADV 1529
Cheung	Comission	Public Utility Commission of Oregon
Cheung	Report	results of operations report
Cheung	FERC	Federal Energy Regulatory Commission
Cheung	REC	Renewable Energy Certificate
Cheung	RPS	Renewable Portfolio Standard
Cheung	NEO	Named Executive Officers
Cheung	WEBA	Wage and Employee Benefits adjustments
Cheung	Non-T&D	non-transmission and distribution
Cheung	SG	system generation
Cheung	KRRC	Klamath River Renewal Corporation
Cheung	WRAP	Western Resource Adequacy Program
Cheung	COSR	Committee of State Regulators
Cheung	EDIT	Excess Deferred Income Tax
Cheung	TCJA	Tax Cut and Jobs Act
Cheung	SB	Senate Bill
Cheung	PTC	Production Tax Credit
Cheung	ADIT	Accumulated Deferred Income Tax
Cheung	MWh	megawatt-hour
Cheung	AFUDC	Allowance for Funds Used During Construction
Cheung	OCAT	Oregon Corporate Activity Tax
Cheung	Metro BIT	Metro Business Income Tax
Cheung	DSP	Distribution System Plan
Cheung	PHFU	Plant Held for Future Use
Cheung	MBTR	modified blended treasury rate
Cheung	KHSA	Klamath Hydroelectric Settlement Agreement

Coleman	BHE	Berkshire Hathaway Energy Company
Coleman	Commission	Public Utility Commission of Oregon
Coleman	U.S.	United States
Meredith	RMA	Rate Mitigation Adjustment
Meredith	TAM	Transition Adjustment Mechanism
Meredith	2021 Rate Case	Docket UE 374
Meredith	kW	kilowatt
Meredith	FERC	Federal Energy Regulatory Commission
Meredith	Marginal Cost Study	PacifiCorp's State of Oregon December 2024 Marginal Cost Study
Meredith	MWh	megawatt-hours
Meredith	2023 Rate Case	Docket UE 399
Meredith	kWh	kilowatt-hour
Meredith	MidC	Mid-Columbia
Meredith	O&M	operation and maintenance
Meredith	Non-NPC	Non-net Power Costs
Meredith	IOU	investor owned utility
Meredith	WEIM	Western Energy Imbalance Market
McVee	Commission	Public Utility Commission of Oregon
McVee	ROE	return on equity
McVee	ROR	rate of return
McVee	CSS	Customer Service System
McVee	2020 Protocol	2020 PacifiCorp Inter-Jurisdictional Allocation Protocol
McVee	kilovolt	kV
McVee	WMP	Wildfire Mitigation Plan
McVee	PCAM	Power Cost Adjustment Mechanism
McVee	CBIAG	Community Benefits and Input Advisory Group
McVee	IRP	Integrated Resource Plan
McVee	DSP	Distribution System Planning
McVee	CEP	Clean Energy Plan
McVee	TE	Transportation Electrification
McVee	CBI	customer benefit indicators
McVee	LID	Low-Income Discount program
McVee	SMI	state medium income
McVee	DEI	Diversity, Equity & Inclusion
Steward	Commission	Public Utility Commission of Oregon
Steward	GRC	General Rate Case
Steward	2020 Protocol	2020 PacifiCorp Inter-Jurisdictional Allocation Protocol
Steward	WMP	Wildfire Mitigation Plan
Steward	PSPS	Public Safety Power Shutoff
Steward	AEGIS	Associated Electric & Gas Insurance Services Limited
Steward	S&P	Standard & Poor's
Steward	Moody's	Moody's Investors Service
Steward	MSP	Multi-State Process
Steward	IOU	investor-owned utility
Steward	SO	System Overhead
Steward	EFR	Elevated Fire Risk Reclosers
Kobliha	S&P	Standard & Poor's
Kobliha	BHE	Berkshire Hathaway Energy
Kobliha	Test Period	calendar year 2025 test period
Kobliha	CFO Pre-WC/Debt	pre-working capital divided by debt
Kobliha	FFO	funds from operations
Kobliha	SACP	stand-alone credit profile
Kobliha	WUTC	Washington Utilities and Transportation Commission
Kobliha	Alaska Commission	Regulatory Commission of Alaska
Kobliha	FERC	Federal Energy Regulatory Commission
Kobliha	Louisiana Commission	Louisiana Public Service Commission
Kobliha	ML&P	Anchorage Municipal Light and Power
Kobliha	Missouri River	Missouri River Energy
Kobliha	U.S.	United States

Mudge	Commission	Public Utility Commission of Oregon
Mudge	Brattle	The Brattle Group
Mudge	PG&E	Pacific Gas and Electric Company
Mudge	SCE	Southern California Edison
Mudge	CPUC	California Public Utilities Commission
Mudge	AB 1054	California Assembly Bill 1054
Mudge	O&M	operating and maintenance expense
Mudge	PG&E, SCE, and SDG&E	California IOUs
Mudge	ROE	return on equity
DeMers	OCA	Wyoming Office of Consumer Advocate
DeMers	Commission	Public Utility Commission of Oregon
DeMers	Refunds	Line Extension Refunds
DeMers	Advances	Line Extension Advances
DeMers	kW	kilowatts
DeMers	FERC	Federal Energy Regulatory Commission

CERTIFICATE OF SERVICE

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

Service List
UE 433

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Dated this 14th day of February, 2024.

Carrie Meyer
Carrie Meyer
Adviser, Regulatory Operations

CERTIFICATE OF SERVICE

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Dated this 14th day of February, 2024.

Carrie Meyer

Carrie Meyer
Adviser, Regulatory Operations

Docket No. UE 433
Exhibit PAC/100
Witness: Cindy A. Crane

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Cindy A. Crane

February 2024

TABLE OF CONTENTS

ATTACHED EXHIBIT

I. INTRODUCTION AND QUALIFICATIONS

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

A. My name is Cindy A. Crane, and my business address is 825 NE Multnomah Street, Suite 2000, Portland, Oregon 97232. I am currently employed as Chief Executive Officer of PacifiCorp.

Q. Please describe your professional experience.

A. I joined PacifiCorp in 1990. Since then I have served as Director of Business Systems Integration, Managing Director of Business Planning and Strategic Analysis, Vice President of Strategy and Division Services, and Vice President of Interwest Mining Company and Fuel Resources. My responsibilities in these positions included the management and development of PacifiCorp's 10-year business plan, managing the construction of the Company's Wyoming wind plants, directing operations of the Energy West Mining and Bridger Coal companies, and coal supply acquisition and fuel management for PacifiCorp's coal-fired generating plants. From October 2014 until my retirement in 2018, I served as President and Chief Executive Officer (CEO) of Rocky Mountain Power. In that position, I was responsible for the Company's business affairs in the states of Idaho, Utah, and Wyoming. I was accountable for managing the Company's infrastructure investments and operations in order to deliver safe and reliable electric service to our customers at reasonable prices, which included a reasonable return to investors. Following my retirement from PacifiCorp in 2018, I remained active in the energy industry, most recently serving as board chair and CEO of Enchant Energy Corporation, an emerging environmental services company focused on decarbonization for customers and communities. In September 2023, I was appointed CEO of PacifiCorp.

Q. Have you testified in other regulatory proceedings?

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

II. PURPOSE OF TESTIMONY

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

A. My testimony provides an overview of PacifiCorp, and its Oregon service area. I also discuss the escalating wildfire risk that the Company is facing since its last filed general rate case and the steps the Company is taking to address those risks. Further, I discuss the Company's reason for filing the current rate case. Finally, I introduce the Company witnesses that provide direct testimony in support of PacifiCorp's rate request.

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 approximately 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. 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 (U.S.).

Q. Please describe PacifiCorp's Oregon service area.

A. In Oregon, PacifiCorp serves over 627,000 customers. Maps of the Company's service territory are provided in Exhibit PAC/101. The Company's Oregon service area is comprised of urban and rural areas across varied geographic regions in Oregon including coastal, central, eastern, northern, southern, and the Willamette Valley. PacifiCorp serves on average approximately 29 customers per square mile.[1] 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. Figures 1 and 2 below provide the number of retail customers and usage by customer class.

[1] In contrast, a utility serving a more urban area such as Portland General Electric Company serves on average 231 customers per square mile. *See*, https://portlandgeneral.com/about/info/quick-facts 922,444 retail customers across 4,000 square miles.

Figure 1

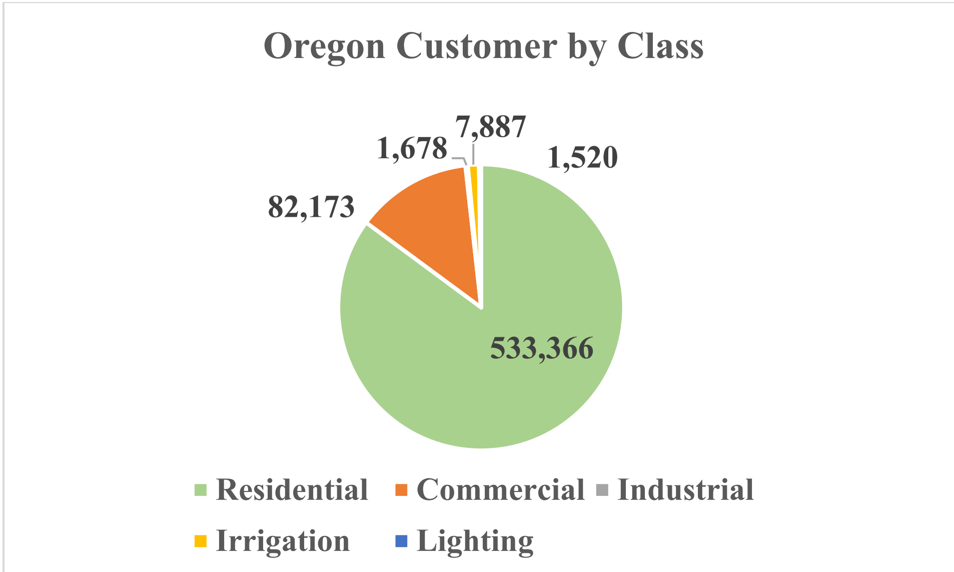
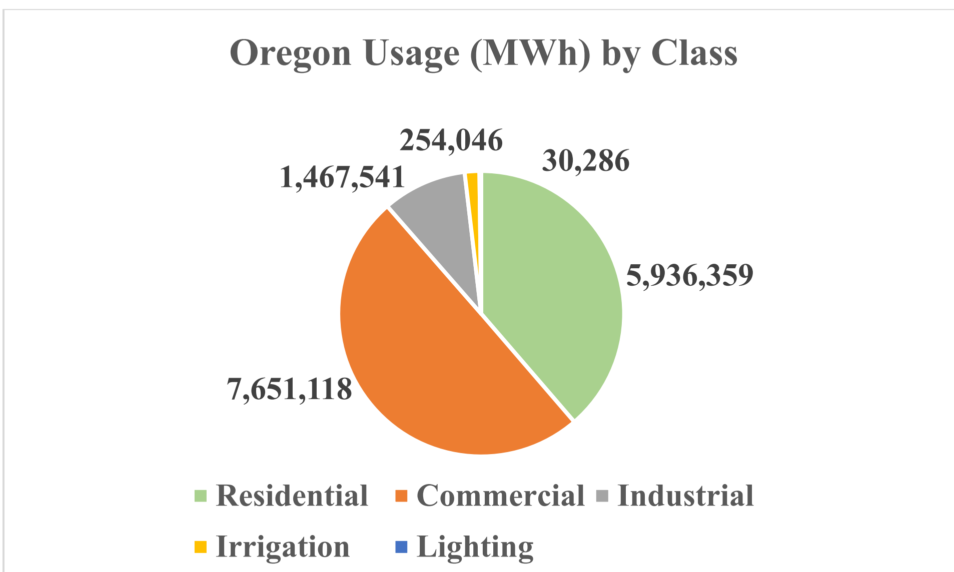


Figure 2



Q. What is the Company's core principle in providing service to customers?

A. The Company's core principle is to provide energy solutions in the form of safe, reliable, and affordable energy to customers in Oregon and throughout the West. The Company has upheld this ideal for over 110 years and remains steadfast in this commitment even as the electricity sector transforms through changing economics and public policies, emerging and maturing technologies, and the rise of a regional energy market.

This energy sector transformation has the Company operating under tremendous cost pressures as it addresses a number of issues, including increased severity and frequency of wildfires, large load growth, and decarbonization of the grid. Despite these challenges, the Company has continued to deliver safe and reliable electric service at low-cost. PacifiCorp's efficient operations for customers have resulted in the Company's average price being approximately 31 percent lower than the national average for investor-owned utilities of 13.63 cents per kilowatt-hour for the 12 months ending June 30, 2023, as reported by the Edison Electric Institute Summer 2023 Typical Bills and Average Rates Report.

As I discuss further below, in this proceeding, the Company is requesting a rate increase that is driven by the increasing costs of operations, such as capital investments needed to serve customers, and costs associated with the growing financial pressures due to the escalating wildfire risks in the West. In response to the latter, the Company is setting forth proposals to address this risk and support the financial stability of the utility.

IV. THE COMPANY'S CURRENT RATE FILING

Q. Since PacifiCorp last filed a rate case in March 2022 (2023 Rate Case),[2] what risks have increased with respect to operations?

A. The Company has experienced and continues to experience escalating wildfire risk, which has impacted costs of operations, such as insurance, and financing. Escalating extreme weather events have become a challenge for all industries and are being felt acutely by utilities in the Western U.S., where wildfires are becoming more frequent, longer lasting and more intense. Driving the growth of wildfires in the Western U.S. are prolonged droughts, heatwaves, high wind events, challenging forest management and population growth in the wildland-urban interface. These extreme weather events pose a long-term practical and financial challenge to PacifiCorp's ability to serve customers, jeopardizing affordability and customer reliability. For further discussion of the escalating wildfire risk to utilities in the West, please see the testimony of Company witness Robert S. Mudge.

Q. How have the Company's costs been impacted by the escalating wildfire risks?

A. Setting aside the Company's increasing costs associated with wildfire mitigation, the Company's costs for insurance and financing are two notable examples of how PacifiCorp's costs have been impacted.

First, the insurance industry is facing significant challenges due to wildfires, as it must contend with property damage, business interruptions and liability claims. Increased payouts for wildfire-related claims are resulting in significantly rising

[2] *In the Matters of PacifiCorp, dba Pacific Power, Request for a General Rate Revision,* Docket Nos. UE 399, UM 1964, UM 2134, UM 2142, UM 2167, UM 2185, UM 2186, and UM 2201 (cons.), Order Nos. 22-491 (Dec. 16, 2022) and 23-047 (Feb. 17, 2023).

insurance premiums, making coverage less affordable and in some cases, insurers are pulling out of the market, for individuals and businesses.[3] Company witness Mariya V. Coleman further addresses increasing insurance premium costs.

Second, ratings agencies are reacting to the increased wildfire risks being faced by utilities which is threatening utilities' access to markets. For example, Standard & Poor's currently has PacifiCorp at a BBB+ rating but has PacifiCorp on negative outlook indicating the potential for a further one or more notch downgrade over the next 24 months. If downgraded two more notches, it would put PacifiCorp at BBB-, the last level of investment grade. Moody's downgraded PacifiCorp's senior unsecured issuer rating to Baa1 from A3. Both rating agencies have indicated regulatory support will play a major role in their ongoing ratings assessments and actions. Company witness Nikki L. Kobliha provides further details on the rating agencies and discusses details concerning the Company's financial plan to provide financial support for PacifiCorp at this time.

Q. What actions has PacifiCorp taken to address these escalating risks?

A. To continue the Company's core principles of service in light of these escalating risks, the Company is taking action now to ensure continued provision of safe and reliable service to customers and financial stability. Addressing this threat will require a multi-pronged approach to ensure the Company's financial stability and affordability and reliability for customers:

- Wildfire Mitigation: The Company files annual Wildfire Mitigation Plans in Oregon, which includes (1) investments in meteorology for increased

[3] For example, four western U.S. utilities are facing wildfire-related class action lawsuits: Avista Corporation in Washington, Xcel Energy in Colorado, Hawaiian Electric Company in Hawaii, and PacifiCorp in Oregon.

situational awareness;[4] (2) asset hardening;[5] (3) installing additional field reclosers with upgraded fault detection (similar to relays) and remote setting capability that reduces wildfire risk while minimizing outage impacts to customers; (4) enhanced processes supporting pro-active risk mitigation – Public Safety Power Shutoff, Encroachment and others; and (5) rebuilding overhead lines with covered conductor or converting to underground reducing exposure to interference from trees or other objects.[6]

- Cash management: The Company is suspending annual dividends for five years, and has prioritized capital investments, for example, it has suspended its 2022 All-Source Request for Proposal and is reviewing and revisiting its capital deployment over the coming five years.
- Limitation of Liability: The Company is pursuing tariff changes regarding limitation of liability.[7]
- Insurance proposals: The Company is adapting its insurance coverage options to meet the challenges of the times, which includes two new mechanisms—an Insurance Cost Adjustment that will enable the Company to annually procure insurance for third-party liability using the most economical combination of commercial insurance and insurance through a new Insurance Mechanism and a Catastrophic Fire fund. Company witness Joelle R. Steward's direct testimony discusses these mechanisms.

However, these measures acting alone are insufficient; without regulatory support, greater customer cost increases, reliability issues and state policy implementation impacts are inevitable. Although the wildfire risks are larger than one company, an industry and any single government, timely actions by both the Company and regulatory jurisdictions are critical to ensure the Company's ability to serve customers reliably and affordably and financial stability of the Company.

[4] This includes weather stations (454) providing 24/7 weather data for forecasting of wildfire conditions across our six-state territory down to the circuit level. This information also facilitates operational management as well as risk mitigation planning.
[5] Such as replacing electro-mechanical relays with microprocessor relays throughout the fire high consequence areas to provide quicker fault detection that limits the amount of arc-energy (heat) present in a fault event.
[6] *PacifiCorp's 2023 Wildfire Mitigation Plan*, filed December 29, 2023, Docket No. UM 2207(2).
[7] *In the Matter of PACIFICORP, dba PACIFIC POWER, Advice No. 23-018 (ADV 1545), Modifications to Rule 4, Application for Electrical Service*, filed Oct. 24, 2023, Docket No. UE 428.

Q. Why is the Company filing a rate case at this time?

A. The Company's costs have increased since the 2023 Rate Case. Drivers of the requested overall rate change include significant capital investments in transmission, such as the Gateway South and Gateway West Segment D-1 projects, and renewable resources, such as the Rock Creek I project, increased insurance costs due to wildfire risk, and vegetation management related costs. Company witness Matthew D. McVee addresses the rate case drivers in his testimony. Additionally, the Company is proposing an Insurance Cost Adjustment and Catastrophic Fire Fund that are aimed to address insurance costs, including premiums and claims, that are rising as a result of wildfire risk and that will position the Company to support its financial stability and continued service of safe and reliable service at low cost. Company witness Steward supports these proposals.

PacifiCorp recognizes that its requested increase comes at a time when customers are facing increasing prices for all necessities. The Company's proposals in this proceeding are aimed at minimizing the frequency of rate cases. Further, the Company proactively and aggressively controls the costs that it can. These efforts are demonstrated by the Company successfully minimizing the frequency of general rate cases. In the last 10 years, the Company has filed only two general rate cases, in 2019 and 2022.[8] The Company is also managing its controllable costs in a prudent manner, which is evident in that they are not a material driver in this case despite inflationary pressures.

[8] *See* Docket Nos. UE 374 and UE 399.

PacifiCorp is, and will remain, actively engaged in finding additional ways to leverage our vast, integrated system for the benefit of our customers.

V. 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, Matthew D. McVee, Vice President, Regulatory Policy and Operations, will describe PacifiCorp's request in this proceeding and summarize the regulatory policy of the Company.
- In Exhibit PAC/300, Nikki L. Kobliha, 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.
- In Exhibit PAC/400, 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.
- In Exhibit PAC/500, Robert S. Mudge, Principal at The Brattle Group, discusses the increased wildfire risk and financial exposure faced by utilities in the Western U.S. and explains how PacifiCorp's proposed remedies are reasonable to manage this growing risk.
- In Exhibit PAC/600, Joelle R. Steward, Senior Vice President of Regulation and Customer & Community Solutions, supports an Insurance Cost Adjustment that will support a new insurance mechanism in development and a Catastrophic Fire Fund.
- In Exhibit PAC/700, Mariya V. Coleman, Vice President of Corporate Insurance and Claims for Berkshire Hathaway Energy Company, supports the Company's updated costs associated with insurance premiums.
- In Exhibit PAC/800, Rick T. Link, Senior Vice President of Resource Planning, Procurement and Optimization, provides the economic analyses of the Gateway South and Gateway West Segment D.1 transmission projects.
- In Exhibit PAC/900, Thomas R. Burns, Vice President of Resource Planning and Acquisition, provides the economic analyses of the conversion of Jim Bridger Units 1 and 2 to natural gas, the Rock Creek I wind facility, and the Rock River I repowering project.

- In Exhibit PAC/1000, Richard A. Vail, Vice President of Transmission Services, discusses important transmission and distribution system upgrades that will be completed to serve customers, including the Gateway South and Gateway West Segment D.1 transmission projects.

- In Exhibit PAC/1100, Timothy J. Hemstreet, Vice President of Renewable Energy Development, supports the Company's Rock River I repowering project and its investment in the Fall Creek Hatchery.

- In Exhibit PAC/1200, Jeffrey M. Wagner, Renewable Development Manager, provides support of the prudency of the Rock Creek I wind project.

- In Exhibit PAC/1300, Brad D. Richards, Vice President of Thermal Generation, supports the Company's investment in the gas conversion of Jim Bridger Units 1 and 2 and the flue gas desulfurization pond project at the Jim Bridger Plant.

- In Exhibit PAC/1400, Allen Berreth, Vice President of Transmission and Distribution Operations, supports the wildfire-related transmission and distribution investments and vegetation management expenses in the rate case. He also supports the inclusion of the restoration costs related to the September 2020 wildfires. Finally, he supports the Company's investment in the Juniper Ridge Bend Service Center.

- In Exhibit PAC/1500, William J. Comeau, Vice President of Customer Experience and Innovation, supports the upgrade to the Company's legacy Customer Service System.

- In Exhibit PAC/1600, Kenneth Lee Elder, Jr., Manager of Load Forecasting, supports the Company's load forecast for the test period.

- In Exhibit PAC/1700, Sherona L Cheung, Revenue Requirement Manager, summarizes the overall test year revenue requirement, pro forma adjustments, and the rate base calculation methodology.

- In Exhibit PAC/1800, Anna DeMers, Senior Customer Regulatory Specialist, supports several new proposed policies in response to very large customers, including a Capacity Reservation Charge and an Excess Demand Charge, in addition to extending the period during which very large customers are eligible for Line Extension Refunds.

- In Exhibit PAC/1900, Robert M. Meredith, Director of Pricing and Tariff Policy, provides PacifiCorp's cost of service study and rate design, and discusses how the proposed tariff changes recover the proposed revenue requirement to achieve fair, just, and reasonable prices for customers.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 433
Exhibit PAC/101
Witness: Cindy A. Crane

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

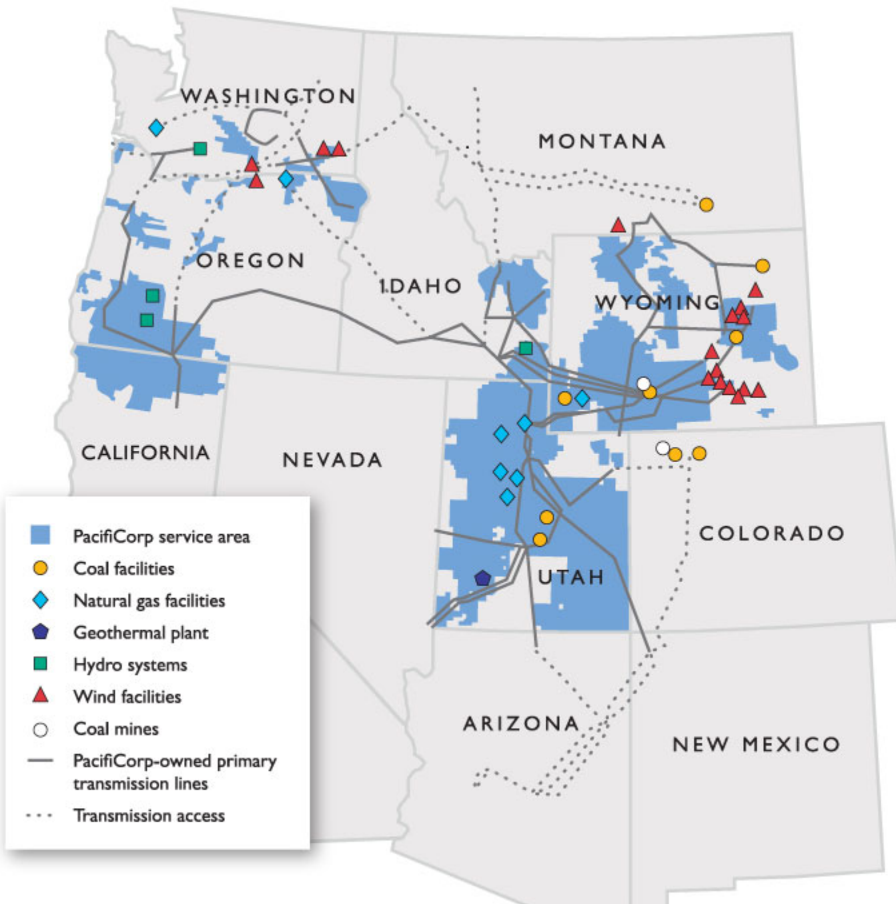
Exhibit Accompanying Direct Testimony of Cindy A. Crane

Maps of PacifiCorp's Service Territory

February 2024

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

PacifiCorp Service Areas



PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Pacific Power Oregon Service Area

Docket No. UE 433
Exhibit PAC/200
Witness: Matthew D. McVee

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Matthew D. McVee

February 2024

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 the Company).

A. My name is Matthew D. McVee and my business address is 825 NE Multnomah Street, Suite 2000, Portland, Oregon 97232. I am currently employed as Vice President, Regulatory Policy and Operations.

Q. Please describe your education and professional experience.

A. I have a Bachelor of Science Degree in Biology from Lewis and Clark College and a Juris Doctorate Degree from Lewis and Clark Law School. I have provided legal counsel to various clients in regulatory matters at both state regulatory commissions and the Federal Energy Regulatory Commission, and acted as administrative attorney to a commissioner at the Nevada Public Utilities Commission. I joined PacifiCorp in 2005 as senior legal counsel for transmission. I became General Counsel for the Western Electricity Coordinating Counsel in 2008. I rejoined the PacifiCorp legal department in 2013. Before taking my current position, I was Chief Regulatory Counsel for PacifiCorp. My current responsibilities include managing regulatory relations with the California, Oregon, and Washington state regulatory commissions, staffs, and stakeholders; developing regulatory policy strategies for PacifiCorp; and managing PacifiCorp's regulatory discovery and filings group.

Q. Have you testified in other regulatory proceedings?

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

II. PURPOSE OF TESTIMONY

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

A. I provide an overview of PacifiCorp's general rate case filing and support the Company's policy positions in the filing. Specifically, I discuss the drivers leading to the requested overall increase in rates of approximately $322.3 million or 17.9 percent.[1] This change in rates is comprised of (1) a base rate increase of $157.7 million; (2) an Insurance Cost Adjustment of $66.0 million, which reflects both amortization of deferred and recovery of on-going insurance premiums; (3) $77.7 million to fund the Company's proposed Catastrophic Fire Fund; (4) the estimated true-up of $21.2 million for the Wildfire Mitigation Plan (WMP) automatic adjustment clause (AAC); and (5) the rebalancing of the Rate Mitigation Adjustment for a reduction of $0.4 million. Further, I explain the steps the Company is taking to incorporate equity in its Oregon operations and planning. Finally, I highlight the policy components of PacifiCorp's rate case.

Q. How is your testimony structured?

A. Section III of my testimony provides an overview of PacifiCorp's last rate case filing. Section IV provides an overview of this rate case filing, including a discussion of key drivers. Section V discusses how the Company incorporates equity into its Oregon operations and planning. Finally, Section VI provides an overview of the Company's insurance proposals.

[1] When combined with a proposed $18.3 million decrease in net power costs in Docket No. UE 434, the overall change results in a net base rate increase of $304.1 million. *See, In the Matter of PacifiCorp. dba Pacific Power, 2025 Transition Adjustment Mechanism,* Docket No. UE 434, filed Feb. 14, 2024.

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 $322.3 million or approximately 17.9 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 Gateway South Transmission Line, Gateway West Segment D1 transmission line, Rock Creek I wind project, Rock River I wind project, and Customer Service System (CSS) Upgrade, for a total Oregon rate base of approximately $5.3 billion, as discussed in the testimony of various witnesses in this rate case;
- Approve an overall cost of capital of 7.740 percent, which is comprised of a capital structure of 50.00 percent equity, 49.99 percent long-term debt, and 0.01 percent preferred stock as supported by Company witness Nikki L. Kobliha; and a return on equity (ROE) of 10.30 percent as supported by Company witness Ann E. Bulkley;
- Approve the Company's proposal to recover third-party liability insurance costs (both deferred and on-going) through a dedicated surcharge, Schedule 80 – Insurance Cost Adjustment as supported by Company witness Joelle R. Steward;
- Approve Oregon's participation in and funding of the Catastrophic Fire Fund through a dedicated surcharge, Schedule 193, to be effective January 1, 2025 as supported by Company witness Steward;
- Approve the allocation of the costs of the Insurance Mechanism and Catastrophic Fire Fund which take into consideration the 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol (2020 Protocol) and new risk metrics as supported by Company witness Steward;
- Approve the Company's request to amortize the deferred costs associated with PacifiCorp's Distribution System Plan, September 2020 wildfire damage and restoration, and the deferred costs related COVID-19 Public Health Emergency incremental to amounts approved for amortization in the Company's 2023 Rate Case, docket UE 399, as supported by myself and Company witness Sherona L. Cheung;
- Approve the Company's request to move all Wildfire Mitigation Plan Operations and Maintenance and Capital Costs eligible for recovery under the WMP AAC from base rates to be recovered through Schedule 190 – Wildfire Mitigation Plan Cost Recovery Adjustment as supported by Company witness Cheung;

- Approve the Company's request to increase the vegetation management costs in base rates from $50 million to $67 million and continue the use of the wildfire mitigation vegetation management mechanism until the Company's next general rate case as supported by Company witness Allen Berreth.

- Approve the cost of service and rate design proposals, including the rebalancing of the Rate Mitigation Adjustment, set forth in the testimony of Company witnesses Robert M. Meredith and Anna DeMers.

III. PREVIOUS RATE CASE HISTORY

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

A. On March 1, 2022, the Company filed its 2023 Rate Case requesting an increase in revenues from Oregon operations of $84.4 million or a 6.8 percent increase to its revenue requirement.[2] Following discussions with the parties in the proceeding, all but a direct access issue was settled through four stipulations. On December 16, 2022, the Commission entered an order approving the first three stipulations, which provided an increase to PacifiCorp's revenue requirement of $49.2 million[3] or 3.7 percent.[4] The fourth stipulation, which concerned the Company's proposed voluntary renewable energy tariff, was contested and ultimately approved by the Commission on February 17, 2023.[5]

IV. 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.

[2] *In the Matters of PacifiCorp, dba Pacific Power, Request for a General Rate Revision,* Docket Nos. UE 399, UM 1964, UM 2134, UM 2142, UM 2167, UM 2185, UM 2186, and UM 2201 (cons.), Order No. 22-491 at 3 (Dec. 16, 2022).
[3] With the impacts of the Oregon Corporate Activity Tax Credit and the rebalancing of the Rate Mitigation Adjustment, the Company's increase was $46.7 million.
[4] Order No. 22.491, Appendix C at 3.
[5] Order No. 23-047 at 9 (Feb. 17, 2023).

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

A. The test period the Company is proposing is a fully forecast test year for the 12 months ended December 31, 2025, with the exception of capital additions, which are based on calendar year-end 2024 balances. The testimony of Company witness Cheung discusses the development of the test year.

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

A. The Company is requesting approval of an overall ROR of 7.740 percent. The overall ROR is comprised of a 10.3 percent ROE as supported by Company witness Bulkley. As explained by Company witness Kobliha, PacifiCorp is requesting to maintain the previously approved capital structure that is comprised of 50.00 percent equity, 49.99 percent long-term debt, and 0.01 percent of preferred stock. Together, this results in a weighted ROE of 5.150 percent. Notably, the Company is requesting an authorized ROE at the lower end of the range recommended by Company witness Bulkley. The Company's proposed ROE balances the impact on customers with the prevailing market conditions that support a higher ROE, as described by Company witness Bulkley, and the Company's increased need to access capital at a reasonable cost in light of the escalating utility risks as discussed by Company witnesses Cindy A. Crane and Kobliha. Company witness Cheung applies the overall ROR to the Company's cost of service.

Q. What allocation methodology is the Company using to allocate costs in this rate case proceeding?

A. To develop the revenue requirement in this proceeding, the Company used the 2020

Protocol which the Commission approved on January 23, 2020.[6] The Commission approved the extension to use the 2020 Protocol through December 31, 2025, on June 30, 2023.[7]

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

A. As I noted above, the Company is requesting an overall increase in rates of approximately $322.3 million. The major drivers of the Company's requested increase in base rates are: (1) capital investments; (2) cost of capital to reflect current market conditions and risk; and (3) wildfire and vegetation management related costs. I discuss each of these drivers in more detail below. In Section VI of my testimony, I discuss the additional driver, costs related to escalating wildfire liability.

Q. Please describe the capital investments driver.

A. The Company continues to make capital investments to bring safe, reliable and low-cost service to its customers. In this rate case processing, the Company is including in capital additions certain significant projects, including the Gateway South and Gateway West Segment D.1 transmission lines, the Rock Creek I wind project, the Rock River I wind project, and the Company's CSS Upgrade.

Q. Please describe the Gateway South and Gateway West Segment D.1 transmission line projects.

A. These transmission projects are key components of the Company's Energy Gateway Transmission Expansion and have been an integral component of the long-term transmission plan for the region for a decade. Gateway South is a 416-mile, high

[6] *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).
[7] Docket No. UM 1050, Order No. 23-229 (June 30, 2023).

voltage 500-kilovolt (kV) transmission line that will connect southeastern Wyoming to central Utah. Gateway West Segment D.1 includes the construction of a new 59-mile, high voltage 230-kV transmission line from the Shirley Basin substation in southeastern Wyoming to the Windstar substation near Glenrock, Wyoming, and a rebuild of approximately 57 miles of the existing Dave Johnston–Shirley Basin 230-kV transmission line. Company witness Richard A. Vail's testimony provides details regarding these transmission projects.

Q. What is the status of construction of the Gateway South and Gateway West Segment D.1 transmission line projects?

A. Construction began on the Gateway South and Gateway West Segment D.1 transmission line projects in June 2022 and September 2022, respectively. Both transmission projects are expected to be in-service in the fourth quarter of 2024. Company witness Vail provides details regarding the construction of these projects.

Q. Do the Gateway South and Gateway West Segment D.1 transmission projects provide benefits to customers?

A. Yes. As explained by Company witnesses Rick T. Link and Vail, the Gateway South and Gateway West Segment D.1 transmission projects will provide a number of benefits including relieving congestion on the transmission system, enabling additional renewable resource interconnections, and improving overall reliability.

Additionally, these resources will help enable the future interconnection of up to 2,500 megawatts (MW) of interconnection and transmission requests, including 13 executed interconnection service and transmission service agreements for over 1,600 MW of new wind resources. While the Company decided to move forward with these transmission projects prior to filing of the Company's inaugural Clean Energy Plan (and the Company is not requesting a Commission determination to what extent these lines contribute to House Bill (HB) 2021's cost cap under ORS 469A.445), to the extent these transmission projects allow for interconnection of PacifiCorp owned or contracted-for renewable or non-emitting resources that are allocated to Oregon customers, each will help lower the Company's overall Oregon-allocated greenhouse gases and contribute to compliance with HB 2021.

Q. Please describe the Rock Creek I and Rock River I wind projects.

A. The Rock Creek I wind project will have a nameplate capacity of 190 MW and is located in Carbon and Albany counties in southeast Wyoming. The project is being developed by Invenergy and was a bid submitted and selected to the final shortlist in the Company's 2020 All-Source Request for Proposal process in the form of a build-transfer agreement and it is currently under construction. Company witness Jeffrey M. Wagner provides further details regarding the Rock Creek I wind project.

The Rock River I wind project will have a nameplate capacity of 49 MW and is located in Wyoming near the Foote Creek Rim. Rock River I was previously co-owned by Terra-Gen and Shell Wind Energy Inc. and its output was sold to the Company under a 20-year power purchase agreement that expired in December 2021. The Company has acquired the facility and is repowering the wind turbines and is expected to be fully online by 2024. Company witness Timothy J. Hemstreet provides further details regarding the Rock River I wind project.

Q. Do the Rock Creek I and Rock River I wind projects provide benefits to customers?

A. Yes. As explained by Company witness Thomas R. Burns, both wind projects are cost-effective ways to meet a substantial near-term need for resources at a time when the region is expected to be resource deficient.

Q. Will Rock Creek I and Rock River I help meet PacifiCorp's compliance obligations under HB 2021?

A. Yes. While the Company decided to move forward with these resources prior to filing the Company's inaugural Clean Energy Plan (and the Company is not requesting a Commission determination to what extent these resources contribute to HB 2021's cost cap under ORS 469A.445), these non-emitting resources will help lower the Company's overall Oregon-allocated greenhouse gases and contribute to compliance with HB 2021.

Q. Please describe the CSS Upgrade.

A. The CSS Upgrade project replaces and updates its current CSS hardware and software. The Company's current CSS was placed in service in the 1990's and has limited ability to incorporate modern services, advanced rate structures, or technologies. Company witness William J. Comeau discusses the CSS Upgrade and how it will benefit customers over time in his testimony.

Q. Please describe the cost of capital driver.

A. In this proceeding, the Company is requesting an increase to the cost of debt and an ROE of 10.3 percent. ROE is important as it establishes the return earned on Company investments that are used to provide safe, reliable service to customers. The

Company relies on financing to support its operations, which requires continued access to the financial markets. Thus, it is important that ROE be set so that the Company continues to have access to the financial markets at reasonable costs, which will allow it to continue to deliver safe and reliable service at lower-cost to its customers.

As Company witness Crane testifies, the Company is responding to escalating wildfire risk and is taking steps to ensure its financial stability and its ability to serve customers with safe and reliable service at lower-cost. For example, one of the steps the Company has taken is that its parent company, Berkshire Hathaway Energy, will not be paid dividends for the next five years. However, the Company's actions are not enough as it also needs regulatory support from the commissions in the states in which it operates. As Company witnesses Kobliha and Bulkley explain, the Commission should establish rates that allow the Company an opportunity to earn an ROE that is adequate to attract capital at reasonable terms and sufficient to ensure financial stability. A utility's shareholders are not the only party that benefit from a healthy utility, its customers and communities in which it operates do as well by reducing the immediate and future borrowing costs related to the financing needed to support regulatory obligations.

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

A. The Company has included for recovery the following costs related to wildfire mitigation, vegetation management, and wildfire restoration. First, the Company has included in revenue requirement capital investments associated with its WMP that are not recovered through its automatic adjustment clause per an agreement with Staff in

Advice No. 23-015 (ADV 1529) and approved by the Commission on January 9, 2024. These capital investments are prudent and reasonable costs that harden the Company's system with respect to wildfire and is work performed in accordance with the WMP.

Second, the Company is proposing to increase the baseline operating and maintenance expense for vegetation management by approximately $17 million, which reflects updates to expenses to meet vegetation management goals. Finally, the Company is requesting recovery of the deferred restoration costs associated with the September 2020 wildfires. These costs represent prudent and reasonable costs to restore service to the Company's customers following the devastating fires that occurred in September 2020.

Company witness Berreth's direct testimony supports the prudence and reasonableness of the recovery of these costs.

Q. Is PacifiCorp seeing inflationary changes 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 2023 Rate Case, docket UE 399. In the Company's filing, inflation accounts for approximately $4.2 million or 2.7 percent of the requested total non-NPC base rates revenue requirement. Company witness Cheung incorporates the impact of inflation on revenue requirement in her testimony.

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

A. Yes. PacifiCorp is requesting to consolidate other applications with this rate case proceeding. Specifically, after this rate case filing, the Company will file a motion to consolidate two open deferral applications to establish ratemaking treatment for these items in this rate case. These applications include:

- Docket UM 2220, Deferred Accounting for PacifiCorp's Distribution System Plan (DSP);[8] and
- Docket UM 2116, Deferred Accounting for costs related to September 2020 wildfire damage and restoration.[9]

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.

Further, the Company is proposing to amortize the remainder of the deferred balance of costs associated with the COVID-19 Public Health Emergency.[10] The Commission first approved amortization of these costs in the Company's 2023 Rate Case. Company witness Cheung testifies regarding the amortization of these deferrals is further addressed in her testimony.

Additionally, the Company is requesting to amortize the insurance premium deferral approved by the Commission in docket UM 2301[11] through a new surcharge, Schedule 80 - Insurance Cost Adjustment. Company witness Steward supports the

[8] *Approval for Operating Cost and Capital Investments Implement the Company's Distribution System Plan* No. 22-260 (July 13, 2023), 1st and 2nd reauthorizations filed on 3, 2023, and Jan. 3, 2024, respectively.
[9] *In the Matter of PacifiCorp dba Pacific Power Application for Deferred Accounting Related to Wildfire Damage and Restoration Costs,* Docket No. UM 2116, Order No. 22-154 (May 9, 2022), Order No. 22-140 (May 9, 2022) (1st reauthorization), 2nd and 3rd reauthorizations filed on Oct. 4, 2022, and Oct. 4, 2023, respectively.
[10] *In the Matter of PacifiCorp dba Pacific Power Application for Reauthorization to Defer Accounting Costs Associated with the COVID-19 Public Health Emergency,* Docket No. UM 2063, Order No. 22-130 (May 9, 2022).
[11] *In the Matter of PacifiCorp dba Pacific Power Application for Authorization of Deferred Accounting Related to Insurance Costs for wildfires,* Docket No. UM 2301, Order No. 24-021 (Jan. 24, 2024).

amortization of these costs through the Insurance Cost Adjustment. Company witness Mariya V. Coleman addresses the prudency and increase of these costs.

Q. Is the Company proposing any changes to the Power Cost Adjustment Mechanism (PCAM) in this general rate case proceeding?

A. No, the Company expects to file a separate tariff with supporting testimony that will propose changes to the PCAM that are necessary in light of significant changes in the industry.

Q. Is PacifiCorp proposing updates to rate design?

A. Yes. The proposed rate design changes for the residential class include increasing the single-family basic charge from $11.00 to $16.00 per month and the multi-family basic charge from $8.00 to $9.00. For residential customers who receive three-phase service, the Company is proposing to replace the demand charge and demand charge minimum with a phase-differentiated basic charge. For the non-residential class, the Company is proposing a Capacity Reservation Charge and an Excess Demand Charge that would be applicable for large customers who reserve more power than they require or use more than the level for which they have contracted. The Company is also proposing a customer-funded substation credit for customers with a load request greater than 25,000 kW following the Commission's approval of changes to Rule 13.[12] The Company is also proposing consolidation and improvement to its time-of-use offerings. The rate design proposals are discussed by Company witnesses Meredith and DeMers.

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[12] *In the Matter of PacifiCorp. dba Pacific Power, Revision of Rule 13 Line Extension Policy,* Docket No. UE 424, Order No. 23-472 (Dec. 13, 2023).

Q. Is the Company requesting interim rates with the filing of its general rate case?

A. No, not at this time. However, as discussed by Company witnesses Crane and Kobliha, the Company has been downgraded by both Moody's and Standard & Poor's during 2023 and credit agencies continue to evaluate the Company's wildfire risk. The Company has taken a number of actions to ensure financial stability and to continue to deliver safe and reliable service to customers. Any further actions from the ratings agencies may require the Company to seek interim rates.

Q. The Company agreed to a stay-out provision in the Third Partial Stipulation approved by the Commission in the 2023 Rate Case.[13] How is seeking interim rates consistent with that provision?

A. It is correct that in the Third Partial Stipulation, PacifiCorp agreed to a one-year general rate case stay-out for calendar year 2023 and that it would not file a general rate case with rates effective earlier than January 1, 2025. However, given the current circumstances as described by Company witnesses Crane and Kobliha, during the pendency of this proceeding, PacifiCorp may have to respond to a material threat to the financial stability of the Company causing it to request interim rates.

V. EQUITY

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

A. In this section of my testimony, I provide an overview of how the Company incorporates equity into its Oregon operations and planning.

Q. Has equity informed the Company's practices and operations?

A. Yes. The Company has incorporated equity in its practices and operations.

[13] Order No. 22-491, Appendix C at 12-13.

Specifically, the Company has taken a number of actions to promote equity in its Oregon service area.

First, the Company offers several opportunities for community engagement to foster a greater understanding of our communities and how we serve them and to allow for input into PacifiCorp's planning process, including

- Community Benefits and Input Advisory Group (CBIAG): The CBIAG, whose members represent environmental justice communities, community-based organizations, and community representatives, focuses on equity and a clean energy future;
- Integrated Resource Plan (IRP) public input meetings: These are multi-month meetings held to solicit feedback from the public on emerging modeling, portfolio, and market-related trends to inform the development of the Company's IRP;
- Distribution System Planning local stakeholder workshops: The Company conducts local workshops to engage with community stakeholders in distribution planning study areas to gather feedback and enhance comprehension of its DSP process. These workshops serve to boost transparency regarding the Company's strategies for planning, investing, and executing solutions within the distribution system. Through these interactions, the Company seeks to foster collaboration in the development of non-wires alternative solutions and ensure that stakeholders are well-informed and have an opportunity to provide feedback regarding distribution system investments to address grid needs identified through the study process.
- Clean Energy Plan (CEP) engagement series: This engagement series, which includes Staff, joint advocates, CBIAG members, and the public was developed to focus on the CEP and its intersectionality with the utility;
- Transportation Electrification (TE) workshops: The purpose of these workshops with local communities is to obtain feedback on the Company's proposed TE investments and TE program offerings; and
- Tribal Nations Engagement series: This engagement series for the Oregon Tribal Nations supports and fosters collaboration, consultation, and shared understanding of Federal, State and local programs, policies, and grants.

Details of the Company's community engagement is set forth in Section II of its 2023 CEP.[14]

Second, the Company has developed interim community benefit indicators (CBIs) and established utility actions within the CEP.[15] The CBIs are designed to demonstrate the impact of PacifiCorp's proposed programs, actions and investments and fall into five categories, resilience (system and community), health and community well-being, environmental impacts, energy equity (distributional and intergenerational equity), and economic impacts.

Finally, the Company has implemented the Oregon Low-Income Discount (LID) program,[16] which is available to income-qualified residential customers and master-metered buildings served under a General Service rate schedule with 50 percent or greater of the individual residential units dedicated to income qualifying occupants. Income-qualified residential customers receive a monthly bill discount at one of two levels based on the customer's household income as a percentage of Oregon state medium income (SMI) adjusted to household size. Customers with household incomes up to 20 percent of SMI will receive a 40 percent discount on their electricity bill and customers with household incomes between 21 percent and 60 percent of SMI will receive a 20 percent discount on their electricity bill. As of December 31, 2023, approximately 46,000 residential customers enrolled in the LID program, of which 81 percent enrolled in the 20 percent discount and 19 percent

[14] *In re PacifiCorp's 2023 Clean Energy Plan* (available here: https://www.pacificorp.com/energy/oregon-clean-energy-plan.html).
[15] *Id.* at 14-29 (providing further details on the Company's CBIs and related utility actions).
[16] The discount program was enabled by House Bill 2475 which modified ORS 757.230 for differential rates and implemented October 1, 2022.

enrolled in the 40 percent discount. There are two master-metered properties with a total of 57 units enrolled in the program. Further, the Company is working with the Energy Trust of Oregon to find ways to complement energy efficiency and demand side management programs and maximize outreach and accessibility for greater customer participation and benefit.

Q. Has the Company established internal equity employee leads?

A. Yes. It has four essential employee leads to support the Company's equity activities:

- **Christina Medina,** Stakeholder Policy & Engagement Manager. Ms. Medina's position was established by the Company's senior management to design, deliver, and successfully implement stakeholder processes and outcomes in response to goals and regulatory requirements in Washington, Oregon, and California. She is also responsible for identifying and developing opportunities for broad and diverse stakeholder engagement and incorporation of feedback from stakeholders into business decision-making and outcomes. Her position also pursues the success of equity-based processes by tracking stated goals and objectives, statutory and regulatory requirements, and expectations. Ms. Medina also oversees the implementation and support of Company programs and policies that directly impact customers and Company goals. Further, she oversees tribal engagement within the Company's western service areas. Critical deliverables include ongoing facilitation of the Equity Advisory Group process (Washington), development and ongoing facilitation of the CBIAG process (Oregon), and ongoing coordination of access and functional needs initiatives in Washington, Oregon, and California.

- **Kimberly Alejandro**, Equity Analyst, is based in Yakima, Washington. The Equity Analyst position was created to support the delivery and implementation of equity-based processes and outcomes to support regulatory requirements in Washington, Oregon, and California. Kimberly Alejandro's role is to build relationships by collaborating with internal and external partners, stakeholders, and equity advisory groups to cultivate an environment of inclusivity with an equity lens. She also provides feedback from the stakeholder process to inform business decisions and supports equity-based functions by tracking goals and objectives to meet regulatory requirements and expectations. Critical deliverables include ongoing facilitation of the Equity Advisory Group process (Washington), development and ongoing facilitation of the CBIAG process (Oregon), and ongoing coordination of access and functional needs initiatives in Washington, Oregon, and California.

- **Tracy Moreland**, Tribal Liaison Representative, is based in Portland, Oregon. The Tribal Liaison Representative position was created to foster and build mutually beneficial relationships between Tribal Governments and PacifiCorp's multi-state service area of Wyoming, Utah, Idaho, California, Oregon and Washington. Ms. Moreland's role is to work with Tribal Governments collaboratively on policy issues, projects and community activities. In addition, she focuses on establishing consistent communications, strong relationships, and continued understanding of tribal culture, traditions, sovereignty, governance, and protocols, as well as working with Tribal Governments and State Agencies supporting Tribal Nations initiatives.

- **Abbie Rice**, Director of Diversity, Equity & Inclusion (DEI), and Community Impact. This position was created to provide leadership and support across PacifiCorp to design, develop and implement innovative strategies to cultivate a work environment that advances DEI. Ms. Rice leads the coordination and evaluation of PacifiCorp's DEI framework, actions, and measurement. Further, she develops and leads implementation of Company-wide programs to support DEI across the employee experience including recruitment, retention, development, and succession planning; assists the Company in evaluating the current state of DEI efforts; identifies gaps and opportunities and supports development and implementation of innovative solutions; supports development and delivery of DEI training; and partners with human resources leaders on policy and practice review, including identifying and developing opportunities for enhancement.

VI. INSURANCE PROPOSALS

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

A. In this section of my testimony, I provide an overview of the two proposals for which the Company is requesting approval to address the escalating wildfire risk that is not only affecting the Company but other utilities in the West.

Q. How has the escalating wildfire risk impacted the Company's operations since its 2023 Rate Case?

A. As explained by Company witnesses Berreth and Robert S. Mudge, there has always been a degree of wildfire risk to utilities operating in the Western United States. However, in recent years, this risk is escalating in frequency and severity, which has resulted in increased wildfire mitigation. This escalating risk has impacted the

Company's operations in several ways, in addition to increased wildfire mitigation capital investment and operating and maintenance expenses. First, as described further by Company witness Coleman, PaciCorp has experienced a substantial increase in the cost of insurance premiums. 2023 insurance premium costs are 18 times greater than comparable 2019 premiums and insurers who have historically sold wildfire insurance may no longer do so. Second, over the course of 2023, as explained by Company witness Kobliha, ratings agencies have downgraded PacifiCorp's credit ratings, threatening its access to the financial markets. Access to the financial markets at reasonable rates aids the Company to provide safe and reliable service at low costs to customers.

Q. Has the Company taken any actions to address this escalating risk?

A. Yes. The Company has taken a number of actions, including filing annual WMPs in Oregon; implementing cash management actions such as, suspending dividends to Berkshire Hathaway Energy for five years and prioritizing capital; and pursuing tariff changes regarding limitation of liability. Company witnesses Crane, Berreth, Steward, and Kobliha discuss these actions further.

Q. Is the Company including proposals to address this risk in this proceeding?

A. Yes, the Company is requesting approval of two proposals in this proceeding. First, the Company is proposing to recover third-party liability insurance costs (both deferred and on-going) through a dedicated surcharge, Schedule 80 - Insurance Cost Adjustment. The Insurance Cost Adjustment will be used to support a new Insurance Mechanism, that provides additional insurance coverage that may not be commercially available at a more economically sustainable cost. Second, the

Company is requesting that the Commission approve Oregon's participation in the Catastrophic Fire Fund, which would provide a pool of funds for the Company to draw upon for extremely large claims that exceed insurance coverage. Company witness Steward supports these proposals and details the multi-state engagement process the Company initiated with stakeholders.

Q. Why are these proposals necessary if the Company is already taking action to address the escalating wildfire risk?

A. The Company's actions are simply not enough. Given the rising insurance costs and dwindling commercial insurance options, these mechanisms will provide support for PacifiCorp and its customers in several ways. First, the Commission has long allowed the recovery of insurance costs in PacifiCorp's rates as it represents a prudent and reasonable cost incurred in the ordinary course of business. Given the rising insurance costs, the proposals will provide PacifiCorp the ability to obtain appropriate coverage at economic costs for its customers. Second, approval of these proposals will provide financial stability as rating agencies are monitoring PacifiCorp's wildfire risks for further downgrades. As I noted above a financially healthy utility does not only benefits it shareholders. It also benefits its customers because a financially healthy utility is positioned to provide safe and reliable service at lower cost.

VII. 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 the Company's overall requested rate increase in this docket of approximately $322.3 million or 17.9 percent.

Q. Does this conclude your direct testimony?

A. Yes.

REDACTED
Docket No. UE 433
Exhibit PAC/300
Witness: Nikki L. Kobliha

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Direct Testimony of Nikki L. Kobliha

February 2024

TABLE OF CONTENTS

ATTACHED EXHIBITS

Exhibit PAC/301—Pro Forma Cost of Long-Term Debt

Exhibit PAC/302—Cost of Preferred Stock

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.

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 50.00 percent and provide support demonstrating why that level is appropriate at this time and how this capitalization benefits customers.

I explain the changes in the Company's credit ratings since the last rate proceeding and the changes to the Company's financial metrics in 2023. I discuss the support needed to achieve Standard & Poor's (S&P) and Moody's credit metric thresholds to maintain the Company's credit rating. I summarize the financial plan that has been established to provide the necessary financial support for PacifiCorp at this time, including the Company's changes to its capital plan and the support provided by Berkshire Hathaway Energy (BHE). I further demonstrate why the requested capital structure is an important component of that plan to support the Company's financial metrics. Finally, I explain why this form of regulatory support benefits customers. I also support PacifiCorp's proposed cost of long-term debt of 5.18 percent and cost of preferred stock of 6.75 percent.

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

A. PacifiCorp proposes an overall cost of capital of 7.74 percent. This cost includes the return on equity recommendation of 10.3 percent as supported by the direct testimony of Company witness Ann E. Bulkley and the capital structure and costs set forth in Table 1.

Table 1: Hypothetical Overall Cost of Capital

Component	% of Total	Cost %	Weighted Ave Cost %
Long-Term Debt	49.99%	5.18%	2.59%
Preferred Stock	0.01%	6.75%	0.00%
Common Stock Equity	50.00%	10.30%	5.15%
	100.00%		7.74%

Q. What time period does your analysis cover?

A. The costs of the long-term debt and preferred stock are measured over the calendar year 2025 test period (Test Period) proposed in this proceeding using an average of the five quarter-ending balances spanning the 12-month period ending December 31, 2025, based on known and measurable changes through December 31, 2025. The capital structure for the Company in this case is a hypothetical capital structure set at a level expected to enable the Company to maintain its current credit ratings. This is a departure from the Company's historical practice of basing the capital structure on the average of the five quarter-ending balances, as further discussed below.

III. PACIFICORP'S HISTORICAL CAPITAL STRUCTURES

Q. How does PacifiCorp's historical actual capital structure compare to what is currently authorized?

A. As shown in Table 2 below, PacifiCorp's historical equity ratio has remained relatively flat in the 2018 through 2023 time period, averaging just below 52 percent. In 2021, and again in 2022, the Commission authorized an equity level of 50 percent effective January 1, 2021. Since that time PacifiCorp's actual equity level has exceeded the authorized level.

Table 2: Historical Actual Capital Structure

As of December 31[1]:	2018	2019	2020	2021	2022	2023
Long-Term Debt	47.89%	48.36%	48.49%	47.69%	46.69%	49.93%
Preferred Stock	0.02%	0.02%	0.01%	0.01%	0.01%	0.01%
Common Equity	52.09%	51.62%	51.50%	52.30%	53.30%	50.06%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

[1] Five quarter-end average % Capital Structure for trailing 12-month period ending December 31 of each period; 2023 period represents preliminary actual results.

Q. Why is the Company proposing a capital structure that differs from its forecast capital structure?

A. In the Company's last rate proceeding, the equity ratio that was agreed to by the parties was composed of 50 percent equity and 50 percent long-term debt. Through

2022, the Company managed to a capital structure in excess of this agreed upon level and it was not until the recent events related to the 2020 wildfires that the equity ratio dropped to the authorized level of 50 percent. As a result of incremental wildfire liability accruals throughout 2023 and settlements that were reached in December 2023, coupled with the Company's sizable capital expenditure plan, the Company's actual capital structure has become, and will continue to be for the foreseeable future, more highly leveraged and the Company's financial risk has increased significantly.

Table 3 presents the Company's forecast capital structure for 2024 and 2025.

Table 3: Forecast Capital Structure

Forecast as of December 31[1]:	2024	2025
Long-Term Debt	55.80%	55.64%
Preferred Stock	0.01%	0.01%
Common Equity	44.19%	44.35%
Total	100.00%	100.00%

[1] Five quarter-end average % Capital Structure for 12-month period ending December 31 of each period.

The result of these circumstances is that the Company faces significant risk of a further credit ratings downgrade at its forecast capitalization. Further, the Company's access to the capital markets is challenged as a result of the risk associated with wildfires. Therefore, PacifiCorp is seeking regulatory support through a ratemaking capital structure that will provide the necessary financial support for its current credit ratings. Supporting the Company's credit ratings, and the ability to access capital in the market when it is required, on reasonable terms, provides benefits to PacifiCorp's customers, particularly at a time when significant capital investment is required in the system to meet ongoing operational requirements and policy objectives.

IV. PACIFICORP'S CREDIT METRICS

Q. What are PacifiCorp's current credit ratings?

A. PacifiCorp's current ratings are shown in Table 4.

Table 4: PacifiCorp Credit Ratings

	Moody's	**S&P's**
Senior Secured Debt	A2	A
Issuer	Baa1	BBB+
Outlook	Stable	Negative

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 and the ability to attract the capital necessary to fund 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 BBB-/Baa3) securities or in some cases even securities rated below a single A rating. A further credit rating downgrade has the potential for the Company's Senior Secured Debt ratings to drop below an A rating, thus further limiting the Company's access to capital. 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, and inventory. Being unable to access funds can risk the successful completion of necessary and critical capital infrastructure projects and would increase the chance of outages and service failures over the long term.

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. Please summarize the Company's historical credit metrics.

A. Confidential Table 5 below presents PacifiCorp's cash from operations pre-working capital divided by debt (CFO Pre-WC/Debt) and funds from operations divided by debt (FFO/Debt) metrics for the period from 2019 through 2024. These are the key metrics relied upon by Moody's and S&P. As shown in this table, the Company's 2023 forecast metrics are in the low end of the target range for Moody's. The Company's forecast metrics for 2024 are in the [redacted] range for Moody's and [redacted] range for S&P. These metrics are on the low side but should be sufficient for the current credit ratings of BBB+/Baa, as long as the Moody's metrics start to improve.

Confidential Table 5: PacifiCorp's Historical Credit Metrics

	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Forecast[3]
CFO Pre-WC/Debt (Moody's) [1]	18.4%	18.2%	21.4%	21.0%	[redacted]	
Moody's Guidance	19-20%	19-20%	19-20%	19-20%		
FFO/Debt (S&P) [2]	17.5%	17.4%	21.9%	22.2%		
S&P Guidance	14-16%	14-16%	14-16%	14-16%		

[1] For 2019 through 2022, CFO Pre-WC/Debt are from Moody's. For 2023 and 2024, Moody's metrics are estimated by PacifiCorp. All years reflect adjustments for wildfire accruals, settlements, wildfire insurance and net power costs.
[2] For 2019 through 2022, FFO/Debt metrics are from S&P. For 2023 and 2024, S&P metrics are estimated by PacifiCorp and reflect adjustments for wildfire accruals.
[3] Metric calculations based on PacifiCorp's proposed 50/50 capital structure in this case.

Q. Please summarize the credit rating agencies' perspectives on the current business risk of PacifiCorp.

A. In June 2023, S&P downgraded PacifiCorp's issuer credit rating to BBB+ from A and lowered PacifiCorp's senior secured credit rating to A from A+. S&P also revised the outlook on PacifiCorp to negative from stable. The negative outlook on PacifiCorp reflects the likelihood that S&P could lower the ratings of PacifiCorp by one or more notches over the next 24 months. Furthermore, S&P revised their assessment of PacifiCorp's group status in the BHE group to strategically important from core. This was based on S&P's belief that BHE would no longer support PacifiCorp under all foreseeable circumstances. A strategically important group rating raises PacifiCorp's credit rating by three notches over PacifiCorp's stand-alone credit profile of BB+. In that report, S&P noted that:

> To incorporate the increasing event risk that may depress credit metrics over our forecasts associated with the potential litigations, we revised our financial policy modifier to negative from neutral. Overall, we assess PacifiCorp's stand-alone credit profile (SACP)

> to 'bb+', reflecting our revised view of PacifiCorp's business risk profile and financial policy modifier.[1]

Following the wildfire settlements in December 2023, S&P affirmed its rating of PacifiCorp at BBB+ with a negative outlook. In that report, S&P noted that the negative outlook:

> …reflects the likelihood that we can lower its ratings over the next 24 months depending on legal developments surrounding wildfires in the company's service territory. Currently, we expect the company's funds from operations (FFO) to debt to be 13% - 15% over our outlook period."[2] S&P further noted that "we could also lower ratings if the company's stand-alone FFO to debt consistently weakens to below 13% or if PacifiCorp contributes to a future significant wildfire.[3]

In November 2023, Moody's downgraded PacifiCorp's senior unsecured issuer rating to Baa1 from A3 and its first mortgage bond rating to A2 from A1. Moody's noted that it expected PacifiCorp's CFO pre-WC to debt ratio to be in the range of 16 to 17 percent beginning in 2024, which is significantly below the original expected range of 19 to 20 percent. Moody's noted that the decline:

> …largely reflects the company's plan to build a cash reserve over the next five years through the suspension of annual dividends estimated at $700 million per year to secure the funding of potential wildfire liabilities through a combination of lower capital expenditures, retaining more cash, and operating with higher leverage.[4]

Further, in December, Moody's noted that wildfire risk was a significant risk for PacifiCorp and has a substantial impact on its credit profile.[5]

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[1] S&P Global Ratings, Research Update: PacifiCorp Downgraded to BBB+, Outlook Revised to Negative: Berkshire Hathaway Energy Co. Outlook Also Negative, June 20, 2023, p. 2.
[2] S&P Global Ratings, Research Update: PacifiCorp Ratings Affirmed Following Archie Creek Settlement; Outlook Negative, December 12, 2023, p. 1.
[3] *Id.*, at 2.
[4] Moody's Rating Action: Moody's downgrades PacifiCorp to Baa1, outlook stable, p. 1.
[5] Moody's Investors Services, Credit Opinion, PacifiCorp, Update following a downgrade to Baa1, December 4, 2023, p. 1.

Q. What other factors will affect the Company's capital structure during the period when rates will be in effect?

A. In addition to the ongoing financing requirements of the regular operations of the business, the Company has $10.6 billion in capital investments over the 2024 through 2026 timeframe. The Company's planned investments include approximately $1.0 billion related to wildfire mitigation, as presented in Confidential Table 6 below.

Confidential Table 6: Forecast Capital Expenditures[1]

Capital Expenditures ($, millions)	**2024**	**2025**	**2026**
Wind Generation	[redacted]		
Electric Distribution			
Electric Transmission			
Solar Generation			
Electric Battery & Pumped Hydro Storage			
Wildfire Mitigation			
Other			
Total Capital Expenditures			

[1] Data is confidential until Form 10-K published on February 25, 2024.

Q. What steps is the Company taking to improve its financial metrics?

A. PacifiCorp has suspended its dividend for the period from 2024 through 2028, which will improve retained earnings and free up available financing that can be used to fund the Company's ongoing capital requirements. In addition, the Company has reviewed its capital plans to restructure the timing and scope of its capital investments. Finally, the Company is proposing that the Commission maintain the equity ratio that was established in the last rate proceeding.

Q. What is the projected effect of the Company's proposal on its financial metrics over the next several years?

A. As shown in Confidential Table 7 below, PacifiCorp's financial plan will support the coverage ratios over the period from 2024 through 2026, with ratios in line with a BBB+ rating. The financial plan builds cash, to cover potential wildfire liabilities but may not be enough and further downward pressure could be placed on PacifiCorp's credit metrics.

Confidential Table 7: PacifiCorp's Projected Credit Metrics

$, billions	2024	2025	2026
Long-term Debt Issuances	[redacted]		
Long-term Debt Maturities			
Proposed Common Equity			
FFO / Debt (Moody's)			

V. REGULATORY PRECEDENT FOR THE USE OF A HYPOTHETICAL CAPITAL STRUCTURE

Q. Is there precedent for regulatory support in the form of a hypothetical capital structure that differs from the Company's actual capital structure?

A. Yes. There are several examples of regulatory commissions providing regulatory support in the form of a hypothetical capital structure that is composed of a greater percentage of equity than a company's actual capital structure. In particular, the Washington Utilities and Transportation Commission (WUTC) has identified criteria for the use of a hypothetical capital structure. In addition, the Regulatory Commission of Alaska (Alaska Commission), the Federal Energy Regulatory Commission (FERC) and the Louisiana Public Service Commission (Louisiana Commission) have all supported the financial integrity of the utilities that they regulate using hypothetical capital structures in certain circumstances.

Q. Please summarize the Washington precedent regarding the use of a hypothetical capital structure.

A. In Dockets UE-170485 and UG-170486 the WUTC established that a "hypothetical capital structure should be reserved for circumstances including, but not limited to, financial hardship or tight capital market conditions."[6]

Q. Please summarize the Alaska regulatory precedent with respect to the use of a hypothetical capital structure to support financial integrity.

A. The Alaska Commission has routinely authorized a hypothetical capital structure in circumstances where they determined that a company's capital structure was impaired. In particular, the Alaska Commission authorized a hypothetical capital structure for Anchorage Municipal Light and Power (ML&P) in several cases from Docket U-87-84[7] to Docket U-99-139 over which time, the Commission increased ML&P's equity ratio significantly from 4.5 percent to 40.4 percent equity. In each case, the Alaska Commission determined that the use of a hypothetical capital structure was appropriate because the company's equity ratio was impaired. In 2005, Docket No. U-05-86, the company indicated that at a 40.4 percent equity ratio, it was no longer impaired and that it enjoyed investment-grade bond ratings.[8]

Q. Please summarize the FERC precedent regarding the use of a ratemaking equity ratio that exceeds the company's actual equity ratio.

A. The FERC, through Order 679, established incentive rate treatment for transmission

[6] Washington Utilities and Transportation Commission v. Avista Corporation, d/b/a Avista Utilities, Dockets UE-170485 and UG-170486 (consolidated), Order 07, Docket UE-171221, Order 02, April 26, 2018, at para 110.
[7] Regulatory Commission of Alaska, Docket No. U-10-31, Order No. 15 at 7 referencing Docket No. U-87-84.
[8] Regulatory Commission of Alaska, Docket No. U-10-21, Order No. 15.

investments that met established criteria for transmission system expansion.[9] One of the incentives considered was the use of a hypothetical capital structure, which has been approved for transmission projects meeting the established criteria.[10] In a recent proceeding, Missouri River Energy (Missouri River) proposed the use of a hypothetical capital structure, composed of 50 percent debt and 50 percent equity to finance its investment and ownership in the Big Stone Project. Missouri River noted that the use of the hypothetical capital structure proposed was needed to produce a debt service coverage ratio that was consistent with Missouri River's current Moody's rating and that absent the capital structure, the financing of Big Stone Project would result in downward pressure on the company's credit rating. The FERC approved the use of a hypothetical capital structure as well as other incentives noting that the requested incentives were tailored to the risks and challenges of the Big Stone Project and also that the hypothetical capital structure would help ensure the maintenance of the company's current credit rating.[11]

Q. Please summarize the Louisiana Commission decision to use a ratemaking equity ratio that is higher than the company's actual equity ratio.

A. In Docket U-17282, Order No. U-17282-C, Gulf States Utilities Company proposed the use of an imputed equity ratio of 40 percent, which was higher than the company's actual equity ratio of 35 percent. The Staff of the Louisiana Commission agreed to this capital structure on the basis that the 40 percent equity ratio was

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[9] *Promoting Transmission Inv. through Pricing Reform, Order No. 679, 116 FERC P 61,057*, *order on reh'g*, *Order No. 679-A, 117 FERC P 61,345 (2006)*, *order on reh'g*, *119 FERC P 61,062 (2007)*.

[10] Federal Energy Regulatory Commission, Docket No. ER23-2284-000, Order on Transmission Rate Incentives and Accepting Tarrif Revisions, Midcontinent Independent System Operator, Inc. (MISO), on behalf of Missouri River Energy Services (Missouri River), August 31, 2023.

[11] Id., at para 21.

consistent with the equity ratios of other utilities that had investment grade first mortgage bonds. At that time, Gulf States Utilities was not investment grade. The Louisiana Commission authorized the use of the 40 percent equity ratio.[12]

Q. Please summarize your conclusions regarding the regulatory precedent for the use of a hypothetical capital structure to support financial integrity.

A. While the Company's actual capital structure is the most appropriate capital structure to rely on in the normal course of business operations, as it reflects the actual financing of the ongoing operations of the business, it is reasonable and appropriate to rely on a hypothetical capital structure in circumstances where there is a need to support a company's credit ratings and overall access to capital. Providing this level of regulatory support helps to maintain the credit quality of the regulated utility and ensures that the company has consistent access to capital on reasonable terms, which provides benefits to customers.

Q. How does PacifiCorp's proposed hypothetical capital structure compare with the capital structures of the proxy group companies relied upon in Company witness Bulkley's calculation of the cost of equity?

A. PacifiCorp's proposed hypothetical equity ratio of 50 percent is well below the average equity ratio of the utility operating companies of the proxy group used in Company witness Bulkley's analysis. As shown in Company witness Bulkley's Exhibit PAC/416, the average equity ratio for Company witness Bulkley's proxy group companies is approximately 52.89 percent and the range is from 45.52 percent

[12] Louisiana Public Service Commission, In RE: Gulf States Utilities Company, Ex Parte Application for an Increase in Rates for Retail Electric Service, Docket No. U-17282, Order No. U-17282-C, p. 5.

to 61.26 percent. Therefore, PacifiCorp's requested equity ratio is within the range established by Company witness Bulkley's cost of equity study.

VI. FINANCING OVERVIEW

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. During periods of significant and sustained capital expenditures, as expected to continue now through calendar year end 2026 and beyond for the potential new renewable and carbon free generation resources and associated transmission identified to meet Oregon's energy policy goals, the Company will need to maintain strong regulatory support through its capital structure and return on equity 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 is critical to continue to provide access to debt financing at competitive rates and access to capital markets on an as-required basis. All of these factors assist in financing expenditures like potential new renewable and carbon free generation resources and associated transmission.

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

A. PacifiCorp has continued needs for additional capital to maintain the transmission and distribution system and 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.

PacifiCorp expects to spend approximately $10.6 billion in capital expenditures from 2024 through 2026 with significant investments in wildfire mitigation efforts as well as renewable energy projects and related transmission. This capital spending will require PacifiCorp to raise funds by issuing new long-term debt in the debt capital markets and retaining all its earnings.

Q. Has PacifiCorp's access to the credit markets changed since the Company's last rate proceeding?

A. Yes. PacifiCorp has had reasonable access to the capital markets since the last rate proceeding, up until the recent credit rating downgrade that resulted from the wildfire liability in Oregon based on an unknown class size. Since that time, the Company has maintained access to capital, however, the costs of that capital have increased, reflecting the risk associated with the wildfire liability and the ongoing operational risk. PacifiCorp spent a significant amount of time talking with its investors in the December 2023 and early January 2024 timeframe leading up to its January 2024 long-term debt offering to provide them a detailed update on our plans to mitigate any further wildfire risk. Although the transaction went well and PacifiCorp was able to access the debt capital markets, some traditional investors in PacifiCorp debt decided to not participate. In addition to the measures to improve its metrics that I discuss below, the Company is proposing regulatory solutions related to the escalating wildfire liability. Those solutions are addressed in Company witness Joelle R. Steward's testimony.

Q. How is BHE providing support to PacifiCorp to improve its metrics?

A. PacifiCorp has consistently benefitted from its affiliation with BHE because there is no dividend requirement. While historically PacifiCorp has paid dividends to BHE to manage the common equity component of the capital structure, in sustained periods of capital investment, PacifiCorp is able to retain earnings to help finance investments and forego dividend payments to BHE. As discussed previously, BHE has pledged that it will not require a dividend from PacifiCorp over the next five years, which will allow PacifiCorp to retain earnings to help finance wildfire settlements and capital investments.

Q. How has the Company revised its investment plans to support its credit profile?

A. PacifiCorp has adjusted its capital investment plan over the next five years, reducing the planned expenditures in 2024 through 2026 by nearly $900 million when compared to previously forecasted amounts. In addition to reducing the capital spending, which increases the credit metrics, the Company has refocused its capital plan in the next three years on wildfire mitigation expenses to reduce the risk of wildfire events, and on investment in the ongoing safety and reliability of the service. In addition, the Company has adjusted the timing of its investments that are required to continue to transition to clean energy resources and renewable resources. The adjustment in the timing of these investments will provide better support for the Company's financial profile in the short term.

Q. Is PacifiCorp's proposed hypothetical capital structure a necessary component of the financial plan to reduce the Company's financial risk and support the Company's credit metrics?

A. Yes. The Company's proposal, to rely on a hypothetical capital structure that is composed of 50 percent debt and 50 percent equity will demonstrate to the credit rating agencies and the market that the Company has the regulatory support needed to improve its financial metrics to stabilize the outlook in the short term. The combination of the suspension of the Company's dividend to BHE, the restructuring of its capital plan, and the proposed capital structure will support PacifiCorp's current credit metrics. As shown in Confidential Table 7 above, this financial plan, including regulatory support at a 50/50 capital structure will result in credit metrics in the range expected by the rating agencies for its current credit rating.

Q. What is the benefit to PacifiCorp's customers of providing support to the Company in the form of a hypothetical equity ratio?

A. Solid credit metrics will reduce PacifiCorp's financial risk, which is necessary to access debt in the market on reasonable terms. Simply stated, providing regulatory support in the form of the proposed hypothetical capital structure will reduce the Company's risk profile and result in lower overall financing costs for customers. This is important because PacifiCorp is in the midst of a period of major capital spending and investing in cost-effective infrastructure to provide electric service that is reliable, clean, and affordable. If PacifiCorp does not have consistent access to the capital markets at reasonable costs, these borrowings and the resulting costs of building new facilities become more expensive than they otherwise would be. The inability to access financial markets can threaten the completion of necessary projects, can impact safe and reliable system operations, and result in a significant liquidity challenge.

Q. How has the Company's strong rating historically benefitted customers?

A. PacifiCorp has historically been able to significantly reduce its cost of long-term debt primarily through obtaining new financings at very attractive interest rates. The lower cost of debt has provided benefits to customers through a lower overall rate of return and lower revenue requirement.

In addition, 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.

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/301, Pro forma Cost of Long-Term Debt, shows that, over the test period, PacifiCorp is projected to have an average of approximately $14.5 billion of first mortgage bonds outstanding, with an average cost of 5.18 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.

VII. FINANCING COST CALCULATIONS

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

A. I have 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, 2024, and concluding with December 31, 2025.

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 8: PacifiCorp Embedded Cost of Long-Term Debt

	Forecast LT Debt O/S ($m)	Pro-forma Weighted Average % Cost of LT Debt	% Cost of Debt Calcs provided in response to OR GRC SDR12
12/31/24	$13,702	5.17%	attach SDR 12-2
03/31/25	$14,902	5.19%	attach SDR 12-3
06/30/25	$14,902	5.19%	attach SDR 12-4
09/30/25	$14,652	5.18%	attach SDR 12-5
12/31/25	$14,600	5.18%	attach SDR 12-6
5QE Ave	**$14,551**	**5.18%**	

Q. Please describe the changes to the amount of outstanding long-term debt between December 31, 2023, and December 31, 2025?

A. Approximately $675 million and $218 million of the Company's fixed rate and variable rate long-term debt, respectively, will mature during this period and I have therefore removed this debt when appropriate in the determination of the proposed average cost of debt. As reflected in Exhibit PAC/301, Pro forma Cost of Long-Term Debt, the Company added new fixed rate long-term debt during the period, a five-, seven-, 10- and 30-year split term offering totaling $3.8 billion was issued in January 2024 and anticipates an additional five- and 10-year split term issuances totaling $1.2 billion in 2025.

Q. Regarding the total $3.8 billion of long-term issuances in January 2024, what were the interest rates, credit spreads and all-in cost of debt for each of the new First Mortgage bond series?

A. See the table below for the summary details including the United States (U.S.) Treasury Benchmark rates, credit spreads and additions to the all-in spread for actual and estimated issuance costs for each of the new approximate five-, seven-, 10- and 30-year term first mortgage bond series issuances from January 2024.

Table 9: $3.8 Billion PacifiCorp Long-Term Debt Issuance

$3.8b PacifiCorp Long-Term Debt Issuance in January 2024

% Cost of Debt Summary:

Series	**2029 Bonds** First Mortgage Bonds due 2/15/29	**2031 Bonds** First Mortgage Bonds due 2/15/31	**2034 Bonds** First Mortgage Bonds due 2/15/34	**2055 Bonds** First Mortgage Bonds due 1/15/55
Principal	$500m	$700m	$1,100m	$1,500m
T-Rate Benchmark	3.905%	3.928%	3.922%	4.092%
Treasury Spread	1.200%	1.400%	1.550%	1.750%
Re-offer Yield	5.105%	5.328%	5.472%	5.842%
Coupon Rate	5.100%	5.300%	5.450%	5.800%
+ Issuance Costs (1)	0.107%	0.090%	0.075%	0.064%
All-In % Cost of Debt	5.212%	5.418%	5.547%	5.906%

(1) Includes actual and current estimated costs.

Q. Regarding the $1.2 billion of new long-term issuances in 2025, 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 five-year and 10-year debt is

1.20 and 1.55 percent, respectively. The recent forward five-year and 10-year U.S. Treasury rates for March 2025 are approximately 3.89 and 4.13 percent, respectively. Issuance costs for five-year and 10-year debt of this type adds approximately 0.13 and 0.10 percent to the all-in cost, respectively. Therefore, as reflected in Exhibit PAC/301, Pro Forma Cost of Long-Term Debt, the Company projects a total all-in cost of long-term debt of 5.22 percent and 5.78 percent, respectively, for the projected new five-year and 10-year long-term debt.

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[13] 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

[13] *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).

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 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 5.18 percent, as shown in PAC/301, Pro forma Cost of Long-Term Debt.

B. Embedded Cost of Preferred Stock

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

A. PAC/302, Cost of Preferred Stock, shows the embedded costs of preferred stock to be 6.75 percent.

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 50.00 percent. This equity ratio is reasonable when compared with the equity ratios of the proxy group companies relied upon in Company witness Bulkley's testimony for the determination of the return on equity. In addition, the Company and parties have agreed to a similar capital structure in the last rate proceeding. Finally, the authorization of this capital structure sends an important message to the financial community regarding the regulatory support for PacifiCorp. When combined with the other elements of the Company's financial plan, including suspended dividends through 2028 to increase retained earnings and a restructuring of the Company's capital investments will provide the necessary financial support and risk mitigation necessary to support the Company's credit metrics and credit ratings. Reviewing PacifiCorp's history demonstrates that a financially strong company provides positive financial benefits to customers in the form of access to capital on reasonable terms, which is very important at this point, where the capital investments necessary to achieve the Company's clean energy goals are significant over the next several years. Finally, when combined with PacifiCorp's updated cost of long-term debt of 5.18 percent and the cost of equity of 10.30 percent recommended by Company witness Bulkley, this produces a reasonable overall cost of capital of 7.74 percent.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 433
Exhibit PAC/301
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

February 2024

PACIFICORP
Electric Operations
Pro-Forma Cost of Long-Term Debt Detail
12 months ended December 31, 2025

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	3.500%	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	3
4	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	4
5	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	5
6	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	6
7	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	7
8	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	8
9	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	9
10	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	10
11	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	11
12	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	12
13	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	13
14	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	14
15	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	15
16	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	16
17	2.900%	Series due June 2052	07/09/21	06/15/52	31	$1,000,000,000	$1,000,000,000	($16,599,374)	$0	$983,400,626	$98.340	2.982%	$29,820,000	17
18	5.350%	Series due Dec 2053	12/01/22	12/01/53	31	$1,100,000,000	$1,100,000,000	($13,292,772)	$0	$1,086,707,228	$98.792	5.431%	$59,741,000	18
19	5.500%	Series due May 2054	05/17/23	05/15/54	31	$1,200,000,000	$1,200,000,000	($11,540,279)	$0	$1,188,459,721	$99.038	5.565%	$66,780,000	19
20	5.100%	Series diue Feb 2029	01/05/24	02/15/29	5	$500,000,000	$500,000,000	($2,510,480)	$0	$497,489,520	$99.498	5.212%	$26,060,000	20
21	5.300%	Series diue Feb 2031	01/05/24	02/15/31	7	$700,000,000	$700,000,000	($4,856,526)	$0	$695,143,474	$99.306	5.418%	$37,926,000	21
22	5.450%	Series diue Feb 2034	01/05/24	02/15/34	10	$1,100,000,000	$1,100,000,000	($8,244,815)	$0	$1,091,755,185	$99.250	5.547%	$61,017,000	22
23	5.800%	Series diue Jan 2055	01/05/24	01/15/55	31	$1,500,000,000	$1,500,000,000	($22,445,179)	$0	$1,477,554,821	$98.504	5.906%	$88,590,000	23
24	5.093%	Pro Forma Series due 2030	03/15/25	03/15/30	5	$600,000,000	$480,000,000	($2,707,200)	$0	$477,292,800	$99.436	5.223%	$25,070,400	24
25	5.676%	Pro Forma Series due 2035	03/15/25	03/15/35	10	$600,000,000	$480,000,000	($3,595,200)	$0	$476,404,800	$99.251	5.776%	$27,724,800	25
26	5.971%	Cur Mat LT Debt Series (repriced)	12/31/25	12/31/55	30		$271,360,000	($2,848,070)	$0	$268,511,930	$98.950	6.047%	$16,409,139	26
27	**5.092%**	**Subtotal - Bullet FMBs**			**24**		**$14,531,360,000**	**($160,284,665)**	**($1,295,995)**	**$14,369,779,340**		**5.181%**	**$752,858,339**	27
28														28
29	**5.092%**	**Total First Mortgage Bonds**			**24**		**$14,531,360,000**	**($160,284,665)**	**($1,295,995)**	**$14,369,779,340**		**5.181%**	**$752,858,339**	29
30														30
31			**REACQ**	**ORG MAT**										31
32			**DATE**	**DATE**										32
33		8.375% Series A QUIDS	11/17/00	06/30/35									$107,887	33
34		8.55% Series B QUIDS	11/17/00	12/31/25									$84,084	34
35		**Long-Term Debt Reacquisition, without refunding amortization**											**$191,971**	35
36														36
37	**5.092%**	**Total Long-Term Debt**			**24**		**$14,531,360,000**	**($160,284,665)**	**($1,295,995)**	**$14,369,779,340**		**5.182%**	**$753,050,310**	37
38														38

Docket No. UE 433
Exhibit PAC/302
Witness: Nikki L. Kobliha

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Nikki L. Kobliha

Cost of Preferred Stock

February 2024

PACIFICORP
Electric Operations
Cost of Preferred Stock
12 Months Ended December 31, 2025

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 433
Exhibit PAC/400
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Ann E. Bulkley

February 2024

TABLE OF CONTENTS

ATTACHED EXHIBITS

I. INTRODUCTION

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. 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 (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, including previously before the Commission, are included as Exhibit PAC/401 to this testimony.

II. PURPOSE AND SUMMARY 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) for PacifiCorp's electric utility operations in Oregon and to provide an assessment of its proposed capital structure to be used for ratemaking purposes.

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

A. I have estimated the market-based cost of equity by applying traditional estimation methodologies to a proxy group of comparable utilities, including the constant growth and multi-stage forms of the Discounted Cash Flow (DCF) model, the Capital Asset Pricing Model (CAPM), the Empirical Capital Asset Pricing Model (ECAPM), and a Bond Yield Risk Premium (BYRP or Risk Premium) analysis. My recommendation also takes into consideration the business and regulatory risk of the Company relative to the proxy group, and the Company's proposed capital structure as compared with the capital structures of the operating utilities of the proxy group companies. While I do not make specific adjustments to my ROE recommendation for these factors, I do consider them in the aggregate when determining where my recommended ROE falls within the range of the analytical results.

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

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

- 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 the Company's cost of equity.
- Section VI explains my selection of the proxy group.
- Section VII describes my cost of equity analyses and the basis for my recommended ROE in this proceeding.

- Section VIII provides a discussion of specific regulatory, business, and financial risks that have a direct bearing on the ROE to be authorized for the Company in this case.

- Section IX provides an assessment of the reasonableness of the Company's proposed capital structure.

- Section X presents my conclusions and recommendations.

III. SUMMARY OF ANALYSES AND CONCLUSIONS

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

A. My analyses and recommendations consider the following:

- The United States (U.S.) Supreme Court's *Hope* and *Bluefield* decisions[1] established the standards for determining a fair and reasonable authorized ROE for public utilities, including consistency of the allowed return with the returns of other businesses having similar risk, adequacy of the return to provide access to capital and support credit quality, and the requirement that the result lead to just and reasonable rates.

- The effect of current and prospective capital market conditions on the cost of equity estimation models and on investors' return requirements.

- The results of several analytical approaches that provide estimates of the Company's cost of equity. Because the Company's authorized ROE should be a forward-looking estimate over the period during which the rates will be in effect, these analyses rely on forward-looking inputs and assumptions (*e.g.*, projected analyst growth rates in the DCF model, forecasted risk-free rate and market risk premium in the CAPM analysis.)

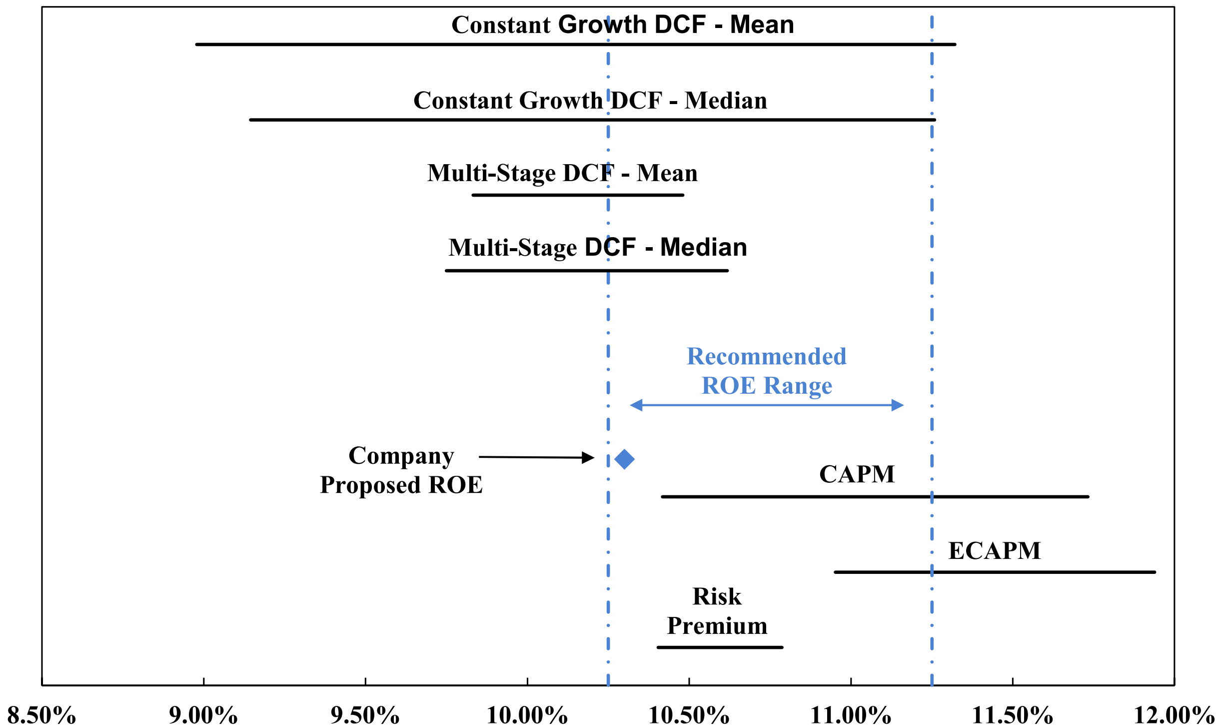
- Although the companies in my proxy group are generally comparable to PacifiCorp, each company is unique, and no two companies have the exact same business and financial risk profiles. Accordingly, I considered the Company's regulatory, business, and financial risks relative to a proxy group of comparable companies in determining where the Company's ROE should fall within the reasonable range of analytical results to appropriately account for any residual differences in risk.

[1] Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591 (1944) (Hope); Bluefield Waterworks & Improvement Co., v. Public Service Commission of West Virginia, 262 U.S. 679 (1923) (Bluefield).

Q. What are the results of the models that you have used to estimate the market-based cost of equity for PacifiCorp?

A. Figure 1 summarizes the range of results produced by the cost of equity analyses.

Figure 1: Summary of Cost of Equity Analytical Results[2]



As shown, the range of results across all methodologies is wide. 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.

[2] *See also* Exhibit PAC/402.

Q. Are prospective capital market conditions expected to affect the results of the cost of equity analyses for the Company during the period in which the rates established in this proceeding will be in effect?

A. Yes. Capital market conditions are expected to affect the results of the cost of equity estimation models. Specifically:

- Long-term interest rates have increased substantially over the past two years and are expected to remain relatively high at least over the next year in response to inflation.
- Since (i) utility dividend yields are less attractive than the risk-free rates of government bonds; (ii) interest rates are expected to remain near current levels over the next year, and (iii) utility stock prices are inversely related to changes in interest rates; utility share prices may remain depressed.
- Rating agencies have responded to the risks of the utility sector, citing factors including elevated capital expenditures, interest rates, and inflation that create pressures for customer affordability and prompt rate recovery, and have noted the importance of regulatory support in their current outlooks.
- Similarly, equity analysts have noted the increased risk for the utility sector as a result of elevated interest rates and expect the sector to underperform in 2024.
- Consequently, it is important to consider that if utility share prices decline, the results of the DCF model, which relies on current utility share prices, would understate the cost of equity during the period that the Company's rates will be in effect.

It is appropriate to consider all of these factors when estimating a reasonable range of the investor-required cost of equity and the reasonableness of the Company's proposed ROE.

Q. What is your recommended ROE for the Company in this proceeding?

A. Considering the analytical results of the market-based cost of equity models and current and prospective capital market conditions, I conclude that an ROE in the range of 10.25 percent to 11.25 percent is reasonable. Based on the Company's regulatory, business, and financial risk relative to the proxy group, I conclude that PacifiCorp has significantly greater risk than the proxy group companies and therefore an ROE at the higher end of the range of results is reasonable. However, the Company is requesting a more moderate return of 10.30 percent. As Company witness Matthew D. McVee explains, the proposed ROE balances the impact on customers with the prevailing market conditions that support a higher ROE and the Company's increased need to access capital at a reasonable costs in light of the escalating utility risks that are discussed by Company witnesses Cindy A. Crane, Nikki L. Kobliha, Ms. Joelle R. Steward, and Ms. Mariya V. Coleman.

Q. Is the Company's requested capital structure reasonable?

A. Yes. The Company's proposed equity ratio of 50.00 percent is well within the range of the actual capital structures of the utility operating subsidiaries of the proxy group companies. Further, the Company's proposed equity ratio is reasonable considering that credit rating agencies have identified in their outlook for the utility sector significant risks such as elevated interest rates and inflation, record levels of capital spending, and the need to fund capital spending in a credit supportive manner. Further, as discussed in the testimony of Company witness Kobliha, the requested capital structure is an important component of the plan to support the Company's financial metrics, which provides benefits to customers in terms of access to capital on reasonable terms.

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 allowed 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 result reached, as opposed to the methodology employed, is the controlling factor in arriving at just and reasonable rates.[3]

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 determination in its 2020 general rate case (2020 GRC) the Commission stated:

> In establishing fair and reasonable rates under ORS 756.040, we balance the interests of the utility investor and customers by 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."[4]

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

Based on these standards, the authorized ROE should provide the Company with a fair and reasonable return and should provide access to capital on reasonable terms in a variety of market conditions.

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 the Company to continue to provide safe, reliable electricity service while maintaining its financial integrity. That return should be commensurate with returns expected elsewhere in the market for investments of equivalent risk. If it is not, debt and equity investors will seek alternative investment opportunities for which the expected return reflects the perceived risks, thereby inhibiting the Company's ability to attract capital at reasonable cost, which negatively affects customers.

Q. Is a utility's ability to attract capital also affected by the ROEs authorized for other utilities?

A. Yes. Utilities compete directly for capital with other investments of similar risk, which include other electric, natural gas, and water utilities nationally. Therefore, the ROE authorized for a utility sends an important signal to investors regarding whether there is regulatory support for financial integrity, dividends, growth, and fair compensation for business and financial risk within that jurisdiction generally, and for that utility particularly. The cost of capital represents an opportunity cost to investors. If higher returns are available elsewhere for other investments of comparable risk over the same time-period, investors have an incentive to direct their capital to those alternative investments. Thus, an authorized ROE significantly below authorized ROEs for other utilities can inhibit the utility's ability to attract capital for investment.

Q. What is the standard for setting the ROE in any jurisdiction?

A. The stand-alone ratemaking principle is the foundation of jurisdictional ratemaking. This principle requires that the rates that are charged in any operating jurisdiction be for the costs incurred in that jurisdiction. The stand-alone ratemaking principle ensures that customers in each jurisdiction only pay for the costs of the service provided in that jurisdiction, which is not influenced by the business operations in other operating companies. In order to maintain this principle, the cost of equity analysis is performed for an individual operating company as a stand-alone entity. As such, I have evaluated the investor-required return for PacifiCorp's electric operations in Oregon.

Q. Does the fact that the Company is a subsidiary of BHE affect your analysis?

A. No. In this proceeding, consistent with stand-alone ratemaking principles, it is appropriate to establish the cost of equity for the Company. More importantly, however, it is appropriate to establish a cost of equity and capital structure that provide the Company the ability to attract capital on reasonable terms on a stand-alone basis and within BHE.

Q. Are the regulatory framework and the authorized ROE and equity ratio important to the financial community?

A. Yes. The regulatory framework is one of the most important factors in investors' assessments of risk. Specifically, the authorized ROE and equity ratio for regulated utilities is very important for determining the degree of regulatory support for supporting a utility's creditworthiness and financial stability in the jurisdiction. To the extent that authorized returns in a jurisdiction are lower than the returns that have been authorized more broadly, such actions are considered by both debt and equity investors in the overall risk assessment of the regulatory jurisdiction in which the company operates.

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

A. Yes. There are numerous examples in which utilities have experienced a negative market response related to the financial effects of a rate decision, including credit rating downgrades and material stock price declines. For example, ALLETE, Inc.,[5] CenterPoint Energy Houston Electric,[6] and Pinnacle West Capital Corporation (PNW)[7] each received credit rating downgrades following rate case decisions in the past few years for reasons that included below average authorized ROEs. The most recent example is the decisions by the Illinois Commerce Commission (ICC) in mid-December 2023 that rejected the multiyear grid plan proposals and authorized lower-than-expected ROEs for both Ameren Illinois Co. (Ameren IL) [8] and Commonwealth

[5] Moody's Investors Service, Credit Opinion: ALLETE, Inc. Update following downgrade, at 3 (Apr. 3, 2019).
[6] Fitch Ratings, Fitch Downgrades CenterPoint Energy Houston Electric to BBB+; Affirms CNP; Outlooks Negative (Feb. 19, 2020).
[7] S&P Capital IQ Pro; Fitch Ratings, Fitch Downgrades Pinnacle West Capital & Arizona Public Service to 'BBB+'; Outlooks Remain Negative (Oct. 12, 2021); Moody's Investors Service, Rating Actions: Moody's downgrades Pinnacle West to Baa1 and Arizona Public Service to A3; outlook negative (Nov. 17, 2021).
[8] Illinois Commerce Commission on Its Own Motion v. Ameren Company d/b/a Ameren Illinois, Order Requiring Ameren Illinois Company to File an Initial Multi-Year Integrated Grid Plan and Initiating Proceeding to Determine Whether the Plan is Reasonable and Complies with the Public Utilities Act, Ameren Illinois Company d/b/a Ameren Illinois, Petition for Approval of a Multi-Year Rate Plan Pursuant to 220 ILCS 5/16-108.18, Docket Nos. 22-0487, 23-0082 (cons.), Order (Dec. 14, 2023) (Ameren Order), Amendatory Order (Jan. 17, 2024).

Edison Co. (ComEd).[9] Specifically, the ICC authorized an ROE for Ameren IL of 8.72 percent and 8.905 percent for ComEd, which were significant reductions from the Administrative Law Judge's recommendations of 9.24 percent and 9.28 percent, respectively.[10]

Q. How did the market respond to the ICC's decisions for these utilities?

A. While the Standard & Poor's (S&P) 500 Index was increasing, the share prices of the parent companies of both Ameren IL and ComEd (*i.e.*, Ameren Corp. and Exelon Corp., respectively) each dropped more than 7 percent on December 14, 2023 after the ICC's decision, and declined again by more than 4.4 percent and 6.4 percent the following day, respectively.[11] As of the close on January 5, 2023, Ameren and Exelon's stock prices were 8.9 percent and 11.4 percent, respectively, below where their stock prices closed on December 13, 2023, or the day immediately prior to the ICC's decisions.[12]

In addition, the reactions of equity analysts were universally negative, and questioned whether the parents of both Ameren IL and ComEd (*i.e.*, Ameren Corp. and Exelon Corp., respectively) will shift their capital spending out of the jurisdiction as a

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[9] Illinois Commerce Commission on Its Own Motion v. Commonwealth Edison Company, Order Requiring Commonwealth Edison Company to File an Initial Multi-Year Integrated Grid Plan and Initiating Proceeding to Determine Whether the Plan is Reasonable and Complies with the Public Utilities Act, Commonwealth Edison Company, Verified Petition for Approval of a Multi-Year Rate Plan Under Section 16-108 of the Public Utilities Act, Docket Nos. 22-0486, 23-0055 (cons.), Order (Dec. 14, 2023) (ComEd Order), Amendatory Order (Jan. 10, 2024).

[10] Ameren Order at 222, 372-374, 398, and 400 (Dec. 14, 2023); ComEd Order at 320, 470-472, 515, 517 (Dec. 14, 2023; *see also,* Allison Good, *Ameren, Exelon shares fall after Illinois regulators reject grid plans*, Platts, (Dec. 15, 2023).

[11] Yahoo! Finance.

[12] Ameren Corp.'s stock price closed at $81.32 on December 13, 2023 and $74.05 on January 5, 2023. Exelon Corp.'s stock price closed at $41.00 on December 13, 2023 and $36.31 on January 5, 2023.

result of the uncertainty associated with the multiyear rate plan and low authorized ROEs. For example:

- Barclays characterized the ICC's ROE authorizations as "draconian" and "one of the lowest awarded in recent memory, especially in an elevated interest rate and cost of capital environment."[13] Barclays also stated it found it hard to believe utilities "can deploy capital under the same magnitude on the updated grid plans to be filed, especially under the current proposed ROE framework."

- In its assessment of the impact on Exelon, the parent of ComEd, UBS stated that, "[t]he actions taken by the ICC today call into question, in our view, the regulatory backdrop in which EXC operates."[14]

- Wells Fargo stated that it was not mincing words, and that the ICC's orders were "onerous" and that:

  > We now view IL as one of the worst regulatory jurisdictions in the U.S. (nipping at CT's heels). We think the totality of the recent orders suggest that the regulatory balancing act between customers and investors is currently heavily skewed toward customers. As a result, we wonder if AEE & EXC will allocate capital away from IL. Keep in mind, IL represents ~25% of both AEE's & EXC's total rate base."[15]

- In its evaluation of Ameren IL, Bank of America (BofA) Securities characterized the ICC's decision as "punitive" and stated that it was a surprise based on numerous conversations with investors that believed the ICC may authorize an ROE above the ALJ's recommendation, not substantially lower, and that the downside surprise was one of the biggest in recent memory for their regulated utility coverage.[16] While BofA Securities acknowledged that Ameren IL represents less than 20 percent of Ameren Corp.'s consolidated rate base, it will nonetheless need to offset capital expenditures elsewhere in order to hit its earnings growth rate targets.[17]

- After the decisions, Guggenheim questioned, "Is Illinois Becoming the Next Connecticut?" Guggenheim noted that investors questioned whether Illinois was "slowly becoming a CT-esque jurisdiction," and that equity and debt

[13] Barlclays, AEE/EXC: Coal Stocking-Stuffer in Illinois (Dec. 14, 2023).
[14] UBS, First Read Exelon Corp., Negative Rate Case Outcome – Rating and PT Under Review (Dec. 14, 2023).
[15] Wells Fargo, The ICC Delivers a Lump of Coal for AEE & EXC (Dec. 14, 2023)
[16] BofA Securities, Ameren Corporation, *Illinois delivers downside surprise* (Dec. 15, 2023).
[17] *Id*.

> holders are going to be wary of Illinois as a jurisdiction going forward and that the ICC is "simply sending a negative message to investors."[18]

Also, after the ICC's decisions, Regulatory Research Associates (RRA) lowered its rating of the Illinois regulatory jurisdiction from Average/2 to Average/3 due to the "concerning pattern of restrictive" rate actions in the state.[19]

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 a reasonable opportunity to recover the return of, and the market-required return on, its invested capital. Accordingly, the Commission's order in this proceeding should establish rates that provide the Company with a reasonable 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. It is important for the ROE authorized in this proceeding to take into consideration current and projected capital market conditions, as well as investors' expectations and requirements for both risks and returns. Because utility operations are capital-intensive, regulatory decisions should enable the utility to attract capital at reasonable terms under a variety of economic and financial market conditions. Providing the opportunity to earn a market-based cost of capital supports the financial integrity of the Company, which is in the interest of both customers and shareholders.

[18] Guggenheim, IL: Is Illinois Becoming the Next Connecticut? To Be Determined, but Taking a Neutral Stance on the State (Dec. 15, 2023).
[19] Russell Ernst, Concerning pattern of restrictive Ill. rate actions prompts rankings revision, Market Intelligence (Dec. 18, 2023).

V. CAPITAL MARKET CONDITIONS

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

A. The models used to estimate the cost of equity rely on market data and thus the results of those models can be affected by prevailing market conditions at the time the analysis is performed. While the ROE established in a rate proceeding is intended to be forward-looking, the analyst uses current and projected market data, including stock prices, dividends, growth rates, and interest rates, in the cost of equity estimation models to estimate the investor-required return for the subject company.

Analysts and regulatory commissions recognize that current market conditions affect the results of the cost of equity estimation models. As a result, it is important to consider the effect of the market conditions on these models when determining an appropriate range for the ROE, and the ROE to be used for ratemaking purposes for a future period. If investors do not expect current market conditions to be sustained in the future, it is possible that the cost of equity estimation models will not provide an accurate estimate of investors' required return during that rate period. Therefore, it is 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 affected by several factors in the current and prospective capital markets, including: (1) changes in monetary policy; (2) relatively high inflation; and (3) increased interest rates that are expected to remain relatively high over the next few years. These factors affect the assumptions used in the cost of equity estimation models.

A. <u>Inflationary Expectations in Current and Projected Capital Market Conditions</u>

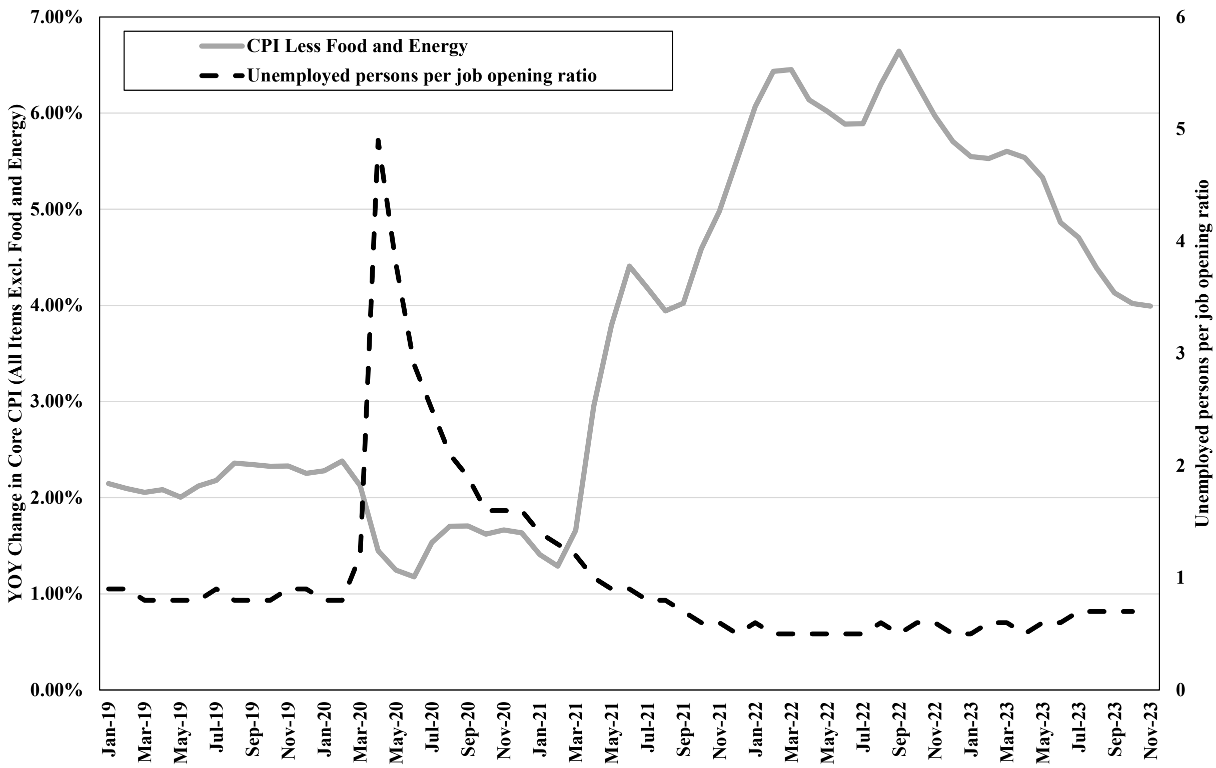
Q. What has the level of inflation been over the past few years?

A. As shown in Figure 2, core inflation increased steadily beginning in early 2021, rising from 1.41 percent in January 2021 to a high of 6.64 percent in September 2022, which was the largest 12-month increase since 1982.[20] Since that time, while core inflation has declined in response to the Federal Reserve's monetary policy, it continues to remain significantly above the Federal Reserve's target level of 2.0 percent.

In addition, I also considered the ratio of unemployed persons per job opening, which is currently 0.7 and has been consistently below 1.0 since 2021, despite the Federal Reserve's accelerated policy normalization. This metric indicates sustained strength in the labor market. Given the Federal Reserve's dual mandate of maximum employment and price stability, the continued increased levels of core inflation coupled with the strength in the labor market has resulted in the Federal Reserve's sustained focus on the priority of reducing inflation.

[20] Figure 2 presents the year-over-year (YOY) change in core inflation, as measured by the Consumer Price Index (CPI) excluding food and energy prices as published by the Bureau of Labor Statistics. I considered core inflation because it is the preferred inflation indicator of the Federal Reserve for determining the direction of monetary policy. Core inflation is preferred by the Federal Reserve because it removes the effect of food and energy prices, which can be highly volatile.

Figure 2: Core Inflation and Unemployed Persons-to-Job Openings, January 2019 to November 2023[21]



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

A. The Federal Reserve has indicated that it expects inflation will remain elevated above its target level until 2026 and that the extent to which it maintains the restrictive monetary policy will depend on market indicators going forward. For example, Federal Reserve Chair Powell at the Federal Open Market Committee (FOMC) meeting on December 13, 2023 observed that while inflation is off of its recent highs, it remains too high and noted that further policy firming is possible based on the data:

> Today, we decided to leave our policy interest rate unchanged and to continue to reduce our securities holdings. Given how far we have come, along with the uncertainties and risks that we face, the Committee is proceeding carefully. We will make decisions about the extent of any additional policy firming and how long policy will remain restrictive

[21] Bureau of Labor Statistics.

> based on the totality of the incoming data, the evolving outlook, and the balance of risks.[22]

Chair Powell reiterated that the FOMC was committed to bringing inflation down to the 2.0 percent target level, and that while the easing of inflation has been good news, it is currently projected to take until 2026 to reach the Federal Reserve's target of 2.0 percent:

> Inflation has eased over the past year but remains above our longer-run goal of 2 percent. Based on the Consumer Price Index and other data, we estimate that total PCE [*Personal Consumption Expenditures]* prices rose 2.6 percent over the 12 months ending in November; and that, excluding the volatile food and energy categories, core PCE prices rose 3.1 percent. The lower inflation readings over the past several months are welcome, but we will need to see further evidence to build confidence that inflation is moving down sustainably toward our goal. Longer-term inflation expectations appear to remain well anchored, as reflected in a broad range of surveys of households, businesses, and forecasters, as well as measures from financial markets. As is evident from the SEP [*Summary of Economic Projections*], we anticipate that the process of getting inflation all the way to 2 percent will take some time. The median projection in the SEP is 2.8 percent this year, falls to 2.4 percent next year, and reaches 2 percent in 2026.[23]

Chair Powell noted that the FOMC members project a gradual decline in the federal funds rates over time, although remain cautious and leave open the possibility of further monetary policy tightening as required:

> While we believe that our policy rate is likely at or near its peak for this tightening cycle, the economy has surprised forecasters in many ways since the pandemic, and ongoing progress toward our 2 percent inflation objective is not assured. We are prepared to tighten policy further if appropriate. We are committed to achieving a stance of monetary policy that is sufficiently restrictive to bring inflation sustainably down to 2 percent over time, and to keeping policy restrictive until we are confident that inflation is on a path to that objective.

> In our SEP [Summary of Economic Projections], FOMC participants wrote down their individual assessments of an appropriate path for the

[22] Federal Reserve, Transcript of Chair Powell's Press Conference, at 1 (Dec. 13, 2023).
[23] *Id*., at 2-3; clarification added.

> federal funds rate based on what each participant judges to be the most likely scenario going forward. While participants do not view it as likely to be appropriate to raise interest rates further, neither do they want to take the possibility off the table. If the economy evolves as projected, the median participant projects that the appropriate level of the federal funds rate will be 4.6 percent at the end of 2024, 3.6 percent at the end of 2025, and 2.9 percent at the end of 2026, still above the median longer-term rate. These projections are not a Committee decision or plan; if the economy does not evolve as projected, the path for policy will adjust as appropriate to foster our maximum employment and price stability goals.[24]

B. The Use of Monetary Policy to Address Inflation

Q. What policy actions has the Federal Reserve enacted to respond to increased inflation?

A. The dramatic increase in inflation has prompted the Federal Reserve to pursue an aggressive normalization of monetary policy, removing the accommodative policy programs used to mitigate the economic effects of COVID-19. Beginning in March 2022 and through September 2023, the Federal Reserve increased the target federal funds rate through a series of increases from a range of 0.00 – 0.25 percent to a range of 5.25 percent to 5.50 percent. While inflation has declined from its peak, it still is above the Federal Reserve's target of 2.0 percent, and therefore, as just noted, the Federal Reserve anticipates maintaining short-term interest rates higher for longer in order to achieve its goal of 2.0 percent inflation over the long-run.

[24] *Id.*, at 3-4.

C. <u>The Effect of Inflation and Monetary Policy on Interest Rates and the Investor-Required Return</u>

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

A. Yes. As the Federal Reserve has substantially increased the federal funds rate in response to increased levels of inflation that have persisted for longer than originally projected, longer term interest rate have also increased. As shown in Figure 3, since the Federal Reserve's December 2021 meeting, the yield on 10-year Treasury bonds has approximately tripled, increasing from 1.47 percent on December 15, 2021 to 4.37 percent at the end of November 2023. Similarly, the yield on the 10-year Treasury bond has increased nearly 150 basis points since the Board's decision in the Company's last rate proceeding.

Figure 3: 10-Year Treasury Bond Yield – January 2021 through November 2023

Q. How have interest rates and inflation changed since the Company's last rate case?

A. As shown in Figure 4, both short-term and long-term interest rates have increased substantially since both the Company filed its surrebuttal testimony in its last rate proceeding and the Commission authorized an ROE of 9.50 percent as part of the settlement in the Company's last rate proceeding. Specifically, long-term interest rates have increased approximately 160 basis points since the Company's updated cost of equity analyses were filed and approximately 100 basis points since the Commission's decision was issued.

Figure 4: Change in Market Conditions Since Company's Last Rate Case

Period	Date	Federal Funds Rate	30-Day Avg of 30-Year Treasury Bond Yield	Core Inflation Rate	Auth'd ROE
Surrebutal - UE-399	7/31/2022	2.32%	3.15%	5.88%	
Decision - UE-399	12/16/2022	4.33%	3.78%	5.70%	9.50%
Current	11/30/2023	5.33%	4.76%	4.02%	

Q. What have equity analysts said about long-term government bond yields?

A. Leading equity analysts have noted that they expect the yields on long-term government bonds to remain elevated. For example, in the most recent Big Money poll released by *Barron's* in October 2023, which surveys money managers regarding the outlook for the next twelve months, two-thirds of the money managers surveyed expect the yield on the 10-year Treasury bond to be at least 4.50 percent in October 2024.[25] Similarly, the consensus estimate of the average yields on the 10-year and 30-year Treasury bonds reported by *Blue Chip Financial Forecasts* are 4.22 percent and 4.48 percent, respectively, through the first quarter of 2025.[26] Therefore, investors expect interest rates to remain elevated for at least the next 15 months. As a result, it is reasonable to expect that if government bond yields remain elevated, the cost of equity will remain materially higher than at the time of the Company's last rate proceeding.

[25] Nicholas Jasinski, Big Money Pros Are Split on the Outlook for Stocks. But They Are Fans of Bonds (Oct. 27, 2023).
[26] *Blue Chip Financial Forecasts*, Vol. 42, No. 12, December 1, 2023, at 2.

D. Expected Performance of Utility Stocks and the Investor-Required Return on Utility Investments

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 that increases in interest rates result in declines in the share prices of utilities and vice versa. For example, Goldman Sachs and Deutsche Bank 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).[27]

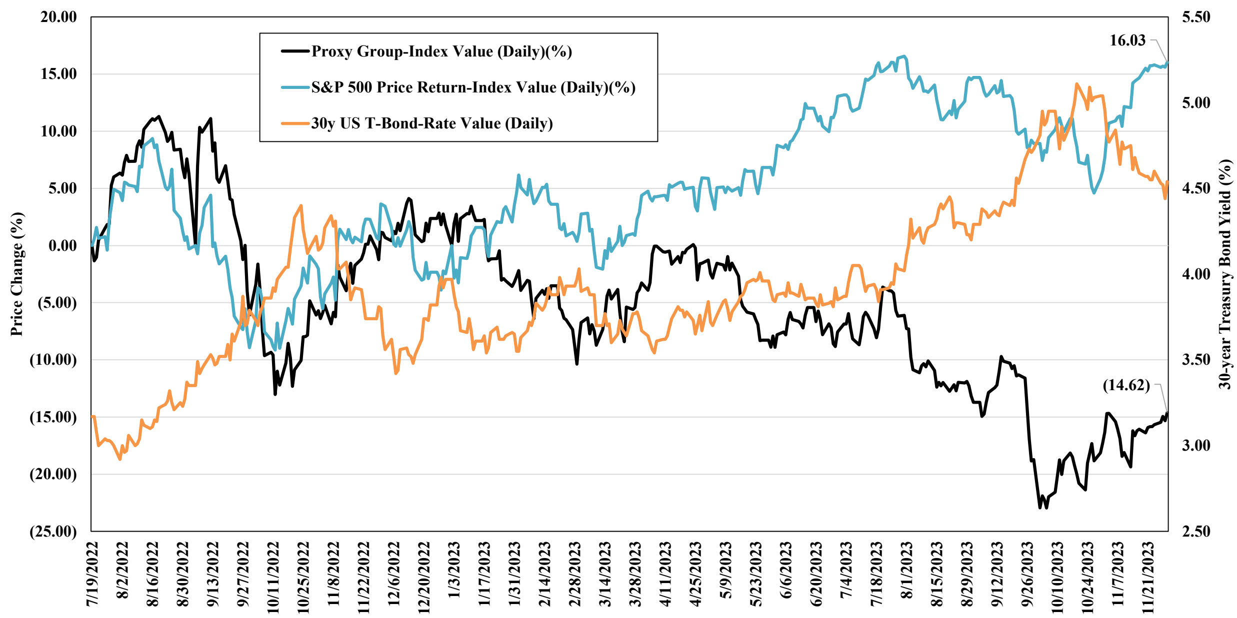
Q. In the Company's last rate proceeding, docket UE 399, you discussed equity analysts' expected underperformance of the utility sector.[28] Did that occur?

A. Yes. Since the filing of my rebuttal testimony in mid-July 2022 in the Company's last rate proceeding, utility stocks have significantly underperformed the broader market, as Treasury bond yields have increased to levels greater than the dividend yields of utility stocks. For example, as shown in Figure 5, since July 19, 2022, the yield on the 30-year Treasury bond has increased by nearly 140 basis points, while the share prices for the vertically-integrated electric utilities included in my proxy group (discussed in the following section) have *declined* by 14.6 percent and the S&P 500 Index has *increased* 16.0 percent. In fact, on October 2, 2023, the utilities sector

[27] Justina Lee, Wall Street Is Rethinking the Treasury Threat to Big Tech Stocks, Bloomberg.com (Mar. 11, 2021).
[28] *In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision,* Docket Nos. UE 399, UM 1964, UM 2134, UM 2142, UM 2167, UM 2185, UM 2186, and UM 2201 (cons.), Exhibit PAC/1400, Bulkley at 38.

dropped by 4.7 percent, its single highest one-day percentage decline since April 2020.[29] The stock price underperformance for the utility sector indicates that the cost of equity has increased since the Company's last rate proceeding.

Figure 5: Relative Performance of the Proxy Group and the S&P 500 Index, Mid-July 2022 through November 2023[30]



Q. How do equity analysts expect the utilities sector to perform in 2024?

A. Equity analysts have recently projected the continued underperformance of the utility sector, and have not changed their views on the sector. For example, Fidelity Investments classifies the utility sector as underweight,[31] and BofA recently noted that they are "not so constructive on [u]tilities" given that the dividend yields for utilities are below both the yields available on long- and short-term treasury bonds.[32] Moreover, the professional investors surveyed by *Barron's* in its most recent Big

[29] Caroline Valetkevich, S&P 500 ends near flat; utilities drop, focus on rate outlook, Reuters (Oct. 2, 2023).
[30] S&P Capital IQ Pro.
[31] Fidelity Investments, Fourth Quarter 2023 Investment Research Update (Oct. 19, 2023).
[32] BofA Global Research, US Utilities & IPPs, As the leaves fall, preparing for Autumn utility outlook. Micro still has potholes (Sept. 6, 2023).

Money poll selected the utility sector as one of the four equity sectors that they liked the least over the next 12 months, indicating they are projecting that utilities will underperform the broader market in 2024.[33]

Q. Why do equity analysts expect the utility sector to continue to underperform over the near-term?

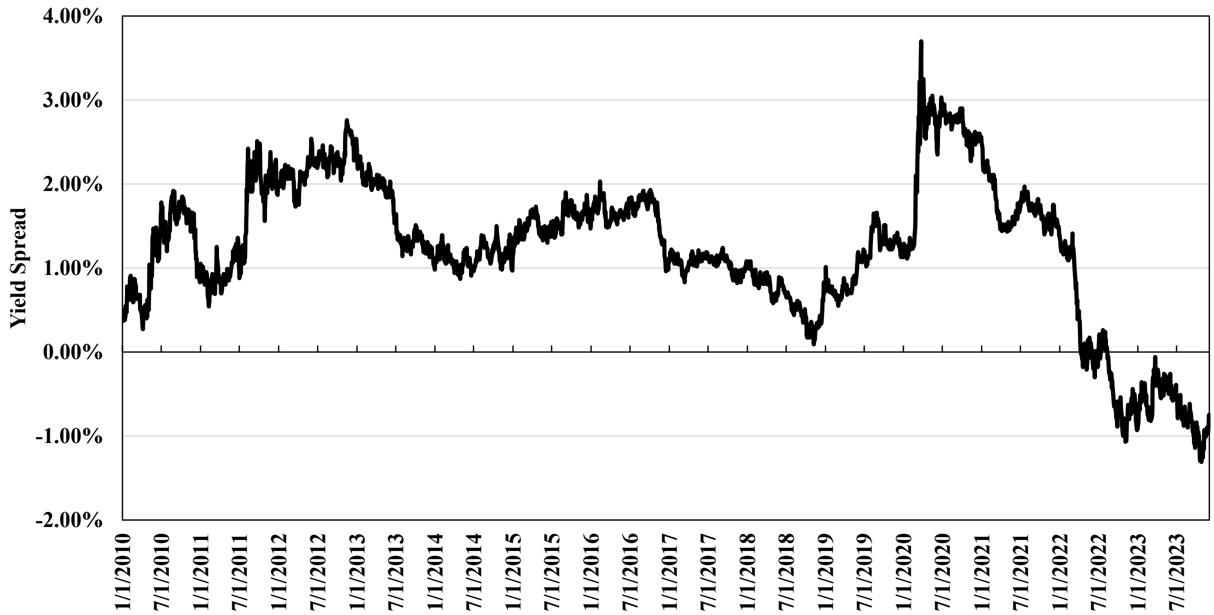
A. Equity analysts expect the utility sector to continue to underperform given that, on average, the yields for the utility sector remain lower than the yields on long-term government bonds. To illustrate this point, I examined the difference between the dividend yields of utility stocks and the yields on long-term government bonds from January 2010 through November 2023 (*i.e.*, yield spread). I selected the dividend yield on the S&P Utilities Index as the measure of the dividend yields for the utility sector and the yield on the 10-year Treasury bond as the estimate of the yield on long-term government bonds.

As shown in Figure 6, the recent significant increase in long-term government bonds yields has resulted in the yield on long-term government bonds exceeding the dividend yields of utilities. The yield spread as of November 30, 2023 was negative 0.87 percent, meaning that the yield on the 10-year Treasury bond exceeds the dividend yield for the S&P Utilities Index. However, the long-term average yield spread from 2010 to 2023 is 1.23 percent. Therefore, the current yield spread is well below the long-term average. Because the yield spread is currently well below the long-term average, and the expectation is that interest rates will remain relatively high through at least the next year, it is reasonable to conclude that the utility sector may

[33] Nicholas Jasinski, Big Money Pros Are Split on the Outlook for Stocks. But They Are Fans of Bonds, Barron's (Oct. 27, 2023).

continue to underperform in 2024. This is because investors that purchased utility stocks as an alternative to the lower yields on long-term government bonds would otherwise be inclined to rotate into government bonds given that the yields on long-term government bonds remain elevated and higher than utility dividend yields, thus resulting in a decrease in the share prices of utilities.

Figure 6: Spread between the Proxy Group Dividend Yield and the 10-year Treasury Bond Yield, January 2010 – November 2023[34]



E. <u>Conclusion</u>

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

A. Due to their effect on the estimated cost of equity, it is important that current and projected market conditions be considered in setting the forward-looking ROE in this proceeding. The combination of persistently high inflation and the Federal Reserve's

[34] S&P Capital IQ Pro and Bloomberg Professional.

changes in monetary policy that have increased interest rates demonstrate that the cost of equity has increased since the Company's last rate proceeding since (i) there is a strong historical inverse correlation between interest rates (*i.e.*, yields on long-term government bonds) and the share prices of utility stocks (*i.e.*, as interest rates increase, utility share prices decline, and thus utility dividend yields increase); and (ii) the yields on long-term government bonds currently exceed the dividend yields of utilities, when historically long-term government bond yields have been lower than the dividend yields of utilities. Because the cost of equity has increased since the Company's last rate proceeding, docket UE 399, cost of equity estimates based in whole or in part on historical or current market conditions, as opposed to projected market conditions, may understate the cost of equity during the future period that the Company's rates will be in effect. Therefore, these current and expected market conditions support consideration of forward-looking cost of equity estimation models such as the CAPM and ECAPM, which better reflect expected market conditions**.**

VI. PROXY GROUP SELECTION

Q. Please provide a brief profile of PacifiCorp.

A. PacifiCorp is an indirect, wholly-owned subsidiary of BHE, and provides electric utility service to approximately 2.0 million residential, commercial and industrial customers in California, Idaho, Oregon, Utah, Washington, and Wyoming.[35] As of December 31, 2022, the Company provided electric service to approximately 617,000 residential, commercial, and industrial customers in Oregon, with approximately 13,700 gigawatt-hours in electric sales.[36] The Company's electric operations in

[35] PacifiCorp SEC Form 10-K, December 31, 2022 at 3.
[36] 2022 Oregon Utilities Statistics Book.

Oregon represented approximately 24 percent of PacifiCorp's electric sales in 2022.[37] PacifiCorp currently has an investment grade long-term rating of BBB+(Outlook: Negative) from S&P and Baa1 (Outlook: Stable) from Moody's.[38] The Company is not separately rated from PacifiCorp.

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

A. In this proceeding, the cost of equity is being estimated for an electric utility company that is not itself publicly traded. Because the cost of equity is a market-based concept and because the Company's operations 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 the Company in certain fundamental business and financial respects to serve as its "proxy" for purposes of estimating the cost of equity.

Even if the Company was a publicly-traded entity, it is possible that transitory events could bias its market value over a given period. A significant benefit of using a proxy group is that it moderates the effects of unusual events that may be associated with any one company. The proxy companies used in my analyses all possess a set of operating and risk characteristics that are substantially comparable to the Company, and thus provide a reasonable basis to estimate the appropriate cost of equity for the Company.

[37] PacifiCorp SEC Form 10-K, December 31, 2022 at 3.
[38] S&P Global Ratings, *PacifiCorp Ratings Affirmed Following Archie Creek Settlement; Outlook Negative* (Dec. 12, 2023); Moody's Investors, Issuer Comment, PacifiCorp, Dec. 8, 2023.

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 DCF model;
- have investment grade long-term issuer ratings from S&P and/or Moody's;
- have positive long-term earnings growth forecasts from at least two utility industry equity analysts;
- own regulated generation assets that are in rate base;
- derive more than 40 percent of its megawatt-hour sales from its owned generation facilities;
- derive more than 60 percent of their total operating income from regulated electric operations; and,
- were not parties to a merger or transformative transaction during the analytical periods relied on.

Q. What is the composition of your proxy group?

A. Applying these screening criteria results in a proxy group consisting of the companies shown in Figure 7 (as well as in Exhibit PAC/403).

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
OGE Energy Corporation	OGE
Pinnacle West Capital Corporation	PNW
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 rate of return for a regulated utility is the weighted average cost of capital, in which the costs of the individual sources of capital are weighted by their respective proportion (*i.e.*, book values) in the utility's capital structure. The ROE is the cost rate applied to the equity capital in calculating the rate of return. While the costs 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 cost of equity determined?

A. The required cost of equity is estimated by using analytical techniques that rely on market-based data to quantify investor expectations regarding equity returns, adjusted for certain incremental costs and risks. Informed judgment is then applied to determine where the company's cost of equity falls within the range of results produced by multiple analytical techniques. 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, as well as the subject company (in the context of the proxy group), in particular.

Q. What methods did you use to estimate the cost of equity for the Company in this proceeding?

A. I consider the results of the constant growth and multi-stage forms of the DCF model, the CAPM, the ECAPM, and a BYRP analysis. A reasonable cost of equity estimate appropriately considers alternative methodologies and the reasonableness of their individual and collective results.

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

A. Yes. 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[39] suggest using the CAPM and Arbitrage

[39] Tom Copeland, Tim Koller and Jack Murrin, *Valuation: Measuring and Managing the Value of Companies*, at 214 (3rd ed. 2000).

Pricing Theory model, while Brigham and Gapenski[40] recommend the CAPM, DCF, and BYRP approaches.

Although the use of multiple analytical approaches is appropriate at all times, current market conditions particularly highlight the importance of using more than one analytical approach to estimating the cost of equity. As discussed previously, interest rates have increased substantially over the past two years and are expected to remain elevated over at least the next year from the lows seen during the COVID-19 pandemic. While the share prices of utilities have declined, the negative yield spread is an indication that utility share prices have not declined sufficiently to account for the recent rise in interest rates. As a result, equity analysts expect the utility sector to continue to underperform, and thus it is reasonable to conclude that the DCF model is likely understating the forward-looking cost of equity that relies on historical share prices to calculate the dividend yield. These recent changes in market conditions highlight the benefit of using multiple models since each model relies on different assumptions, certain of which better reflect current and projected market conditions at different times. As discussed previously, the CAPM, ECAPM, and BYRP analyses offer some balance through the use of both current and projected market data. Accordingly, it is important to use multiple analytical approaches to ensure that the cost of equity results reflect market conditions that are expected during the period that the Company's rates will be in effect.

[40] Eugene Brigham and Louis Gapenski, *Financial Management: Theory and Practice*, at 341 (7th ed. 1994).

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 2020 GRC, 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.[41]

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.[42]

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[41] Docket No. UE 374, Order No. 20-476 at 30.
[42] *Id.*, at 30-31.

A. 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:

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

Where P_0 represents the current stock price, $D1 \ldots D\infty$ 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:

$$k = \frac{D_0(1+g)}{P_0} + g \qquad [2]$$

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 four assumptions: (1) a constant growth rate for earnings and dividends; (2) a stable dividend payout ratio; (3) a constant price-to-earnings ratio; and (4) a discount rate greater than the expected growth rate. To the extent that any of these assumptions are 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 November 30, 2023.

Q. Why do you use 30-, 90-, and 180-day averaging periods?

A. In my constant growth DCF model, I use an average of recent trading days to calculate the term P_0 in the DCF model to ensure that the cost of equity is not skewed by anomalous events that may affect stock prices on any given trading day. The averaging period should also be reasonably representative of expected capital market conditions over the long term.

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

A. Yes. Because 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 twelve-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. However, over the long run, dividend growth can only be sustained by earnings growth, meaning earnings are the fundamental driver of a company's ability to pay dividends. therefore, projected EPS growth is the appropriate measure of a company's long-term growth. In contrast, changes in a company's dividend payments are based on management decisions related to cash management and other factors. For example, a company may decide to retain earnings rather than pay out a portion of those earnings to shareholders through dividends. Therefore, dividend growth rates are less likely than earnings growth rates to accurately reflect investor perceptions of a company's growth prospects. Accordingly, I have incorporated a number of sources of long-term EPS 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. My constant growth DCF model incorporates three sources of long-term projected EPS growth rates: (1) *Zacks Investment Research* (*Zacks*); (2) Yahoo! Finance; and (3) *Value Line*.

Q. Why are EPS growth rates the appropriate growth rates to be relied on in the DCF model?

A. Earnings are the fundamental driver of a company's ability to pay dividends; therefore, projected EPS growth is the appropriate measure of a company's long-term growth. In contrast, changes in a company's dividend payments are based on management decisions related to cash management and other factors. For example, a company may decide to retain earnings rather than pay out a portion of those earnings to shareholders through dividends. Therefore, dividend growth rates are less likely than earnings growth rates to reflect accurately investor perceptions of a company's growth prospects.

Q. How do you calculate the range of results for the constant growth DCF models?

A. I calculate the low-end result for the constant growth DCF model using the minimum growth rate of the three sources (*i.e.*, the lowest of the *Zacks*, Yahoo! Finance, and *Value Line* projected EPS growth rates) for each of the proxy group companies. I use a similar approach to calculate a high-end result, using the maximum growth rate of the three sources for each proxy group company. Lastly, I also calculate results using the average EPS growth rate from all three sources for each proxy group company.

Q. What are the results of your constant growth DCF models?

A. Exhibit PAC/404 and Figure 8 summarize the results of the constant growth DCF models. While I also summarize the DCF results using the minimum growth rates, given the market response to the recent ICC decisions for Ameren IL and ComEd as discussed previously, it is evident that the market would not consider these DCF results reflective of the investor-required return, and thus I do not give these DCF results any material weight at this time.

Figure 8: Constant Growth DCF Model Results

	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Mean Results:			
30-Day Avg. Stock Price	9.08%	10.31%	11.43%
90-Day Avg. Stock Price	9.02%	10.25%	11.37%
180-Day Avg. Stock Price	8.83%	10.06%	11.17%
Average	8.98%	10.21%	11.32%
Median Results:			
30-Day Avg. Stock Price	9.37%	10.10%	11.33%
90-Day Avg. Stock Price	9.17%	10.13%	11.30%
180-Day Avg. Stock Price	8.90%	10.01%	11.14%
Average	9.14%	10.08%	11.26%

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

A. Consistent with prior Commission precedent, I have also considered a multi-stage form of the DCF model. As with the constant growth DCF model, the multi-stage form of the model 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 order in PacifiCorp's 2020 GRC, 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.[43]

While I agree that the multi-stage DCF model is one of the methods considered by 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.

Q. How does the multi-stage form of the DCF model differ from the constant growth form of the DCF model?

A. As with the constant growth DCF model, the multi-stage form of the model defines the cost of equity as the discount rate that sets the current price equal to the discounted value of future cash flows. However, the multi-stage DCF model, which is an extension of the constant growth form of the DCF, 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. What is the structure of the 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 period to the long-term growth period, from years six through 10; and Stage Three is a long-term growth period that begins in year 11

[43] Docket No. UE 374, Order No. 20-476 at 30.

and continues in perpetuity (*i.e.*, years 11 through 200). The cost of equity is then calculated as the rate of return that results from the initial stock investment and the dividend payments over the analytical period.

Q. What growth rates did you rely on in the multi-stage DCF model?

A. As shown in Exhibit PAC/405, I began with the current annualized dividend as of November 30, 2023 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 projected EPS growth rate estimates reported by Yahoo! Finance, Zacks, and *Value Line* that I rely on in the constant growth DCF. For the third stage of the model, I rely on long-term projected growth in gross domestic product (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/406, the projected long-term growth rate is 5.51 percent, which is based on real GDP growth rate of 3.18 percent from 1929 through 2022,[44] plus a projected inflation rate of 2.26 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;[45] (2) the compound annual growth rate of the CPI for all urban consumers for 2033-2050 of 2.27 percent as projected by the Energy Information

[44] U.S. Department of Commerce, Bureau of Economic Analysis, National Income and Product Accounts Tables, Table 1.1.1 (Nov. 29, 2023).
[45] *Blue Chip Financial Forecasts*, Vol. 42, No. 6 at 14 (June 1, 2023).

Administration (EIA);[46] and (3) the compound annual growth rate of the GDP chain-type price index for 2033-2050 of 2.31 percent, also reported by the EIA.[47]

Q. What are the results of your multi-stage DCF models?

A. Figure 9 summarizes the results of the multi-stage DCF model.

Figure 9: Multi-Stage DCF Model Results

	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Mean Results:			
30-Day Avg. Stock Price	9.94%	10.27%	10.60%
90-Day Avg. Stock Price	9.88%	10.21%	10.53%
180-Day Avg. Stock Price	9.68%	9.99%	10.31%
Average	9.83%	10.16%	10.48%
Median Results:			
30-Day Avg. Stock Price	9.87%	10.45%	10.75%
90-Day Avg. Stock Price	9.73%	10.28%	10.68%
180-Day Avg. Stock Price	9.65%	10.02%	10.43%
Average	9.75%	10.25%	10.62%

Q. Have regulatory commissions acknowledged that the DCF model might understate the cost of equity given the current capital market conditions of relatively high inflation and elevated interest rates?

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

[46] U.S. Energy Information Administration, Annual Energy Outlook 2023, Table 20, Macroeconomic Indicators (Mar. 16, 2023).
[47] *Id.*

> To help control rising inflation, the Federal Open Market Committee has signaled that it is ending its policies designed to maintain low interest rates. Aqua Exc. at 9. Because the DCF model does not directly account for interest rates, consequently, it is slow to respond to interest rate changes. However, I&E's CAPM model uses forecasted yields on ten-year Treasury bonds, and accordingly, its methodology captures forward looking changes in interest rates.
>
> Therefore, our methodology for determining Aqua's ROE shall utilize both I&E's DCF and CAPM methodologies. As noted above, the Commission recognizes the importance of informed judgment and information provided by other ROE models. In the 2012 PPL Order, the Commission considered PPL's CAPM and RP methods, tempered by informed judgment, instead of DCF-only results. We conclude that methodologies other than the DCF can be used as a check upon the reasonableness of the DCF derived ROE calculation. Historically, we have relied primarily upon the DCF methodology in arriving at ROE determinations and have utilized the results of the CAPM as a check upon the reasonableness of the DCF derived equity return. As such, where evidence based on other methods suggests that the DCF-only results may understate the utility's ROE, we will consider those other methods, to some degree, in determining the appropriate range of reasonableness for our equity return determination. In light of the above, we shall determine an appropriate ROE for Aqua using informed judgement based on I&E's DCF and CAPM methodologies.
>
> …..
>
> We have previously determined, above, that we shall utilize I&E's DCF and CAPM methodologies. I&E's DCF and CAPM produce a range of reasonableness for the ROE in this proceeding from 8.90% [DCF] to 9.89% [CAPM]. Based upon our informed judgment, which includes consideration of a variety of factors, including increasing inflation leading to increases in interest rates and capital costs since the rate filing, we determine that a base ROE of 9.75% is reasonable and appropriate for Aqua.[48]

Similarly, the Massachusetts Department of Public Utilities in a recent rate case for NSTAR Electric Company concluded that given the recent increase in

[48] *Penn. Pub. Util. Comm'n et.al. v, Aqua Penn. Wastewater Inc.*, Docket Nos. R-2021-3027385 and R-2021-3027386, Opinion and Order at 154–155 (May 12, 2022).

interest rates there was "greater certainty" that the results of the DCF model were understating the cost of equity for the utility.[49]

B. 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 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.[50] 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:

$$K_e = r_f + \beta(r_m - r_f) \quad [3]$$

Where:

K_e = the required market ROE;

β = the beta coefficient of an individual security;

r_f = the risk-free rate of return; 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, because unsystematic risk can be diversified away, investors should only be concerned with systematic or non-

49 Petition of NSTAR Electric Company, doing business as Eversource Energy, pursuant to G.L. c. 164, § 94 and 220 CMR 5.00, for Approval of a General Increase in Base Distribution Rates for Electric Service and a Performance Based Ratemaking Plan, Docket D.P.U. 22-22, Final Order at 385-386 (Nov. 30, 2022).

50 Systematic risk is the risk inherent in the entire market or market segment, which cannot be diversified away using a portfolio of assets. Unsystematic risk is the risk of a specific company that can, theoretically, be mitigated through portfolio diversification.

diversifiable risk. Systematic risk is measured by beta, which is a measure of the volatility of a security as compared to the market as a whole. Beta is defined as:

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

Variance (r_m) represents the variance of the market return, which is a measure of the uncertainty of the general market. *Covariance* (r_e, r_m) represents the covariance between the return on a specific security and the general market, which 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 rely on three sources for my estimate of the risk-free rate (1) the current 30-day average yield on 30-year U.S. Treasury bonds, which is 4.77 percent;[51] (2) the average projected 30-year U.S. Treasury bond yield for the first quarter of 2024 through the first quarter of 2025, which is 4.48 percent;[52] and (3) the average projected 30-year U.S. Treasury bond yield for 2025 through 2029, which is 4.10 percent.[53]

Q. What beta coefficients do you use in your CAPM analysis?

A. As shown in Exhibit PAC/407, I use the beta coefficients for the proxy group companies as reported by Bloomberg and *Value Line*. The beta coefficients reported by Bloomberg are calculated using ten years of weekly returns relative to the S&P 500 Index. The *Value Line* beta coefficients are calculated based on five years of

[51] Bloomberg Professional, as of November 30, 2023.
[52] *Blue Chip Financial Forecasts*, Vol. 42, No. 12, at 2 (Dec. 1, 2023).
[53] *Blue Chip Financial Forecasts*, Vol. 42, No. 12, at 14 (Dec. 1, 2023).

weekly returns relative to the New York Stock Exchange Composite Index. Additionally, as shown in Exhibit PAC/407, I also consider an additional CAPM analysis that relies on the long-term average utility beta coefficient for the companies in my proxy group from 2013 through 2022, which are presented in Exhibit PAC/408.

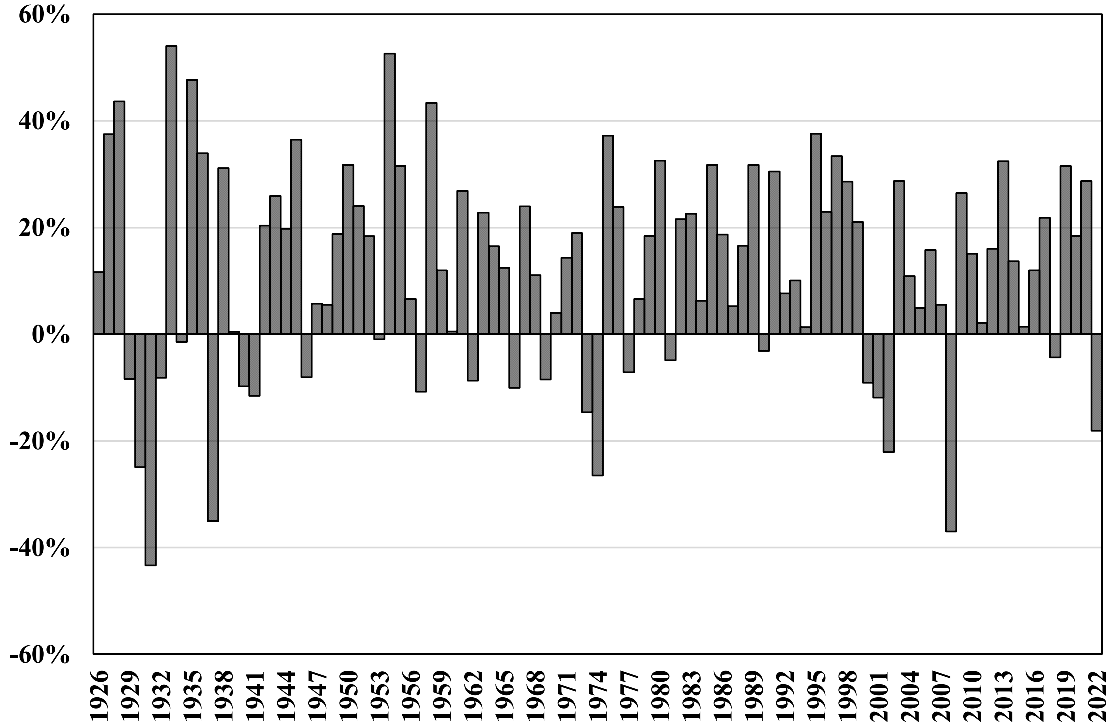
Q. How do you estimate the market risk premium in the CAPM?

A. I estimate the market risk premium as the difference between the implied expected equity market return and the risk-free rate. As shown in Exhibit PAC/409, the expected market return is calculated using the constant growth DCF model discussed previously as applied to the companies in the S&P 500 Index. Based on an estimated market capitalization-weighted dividend yield of 1.88 percent and a weighted long-term growth rate of 10.78 percent, the estimated required market return for the S&P 500 Index as of November 30, 2023 is 12.56 percent.

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

A. As show in Figure 10, given the range of annual equity returns that have been observed over the past century, a current expected market return of 12.56 percent is not unreasonable. In 50 out of the past 97 years (or approximately 52 percent of observations), the realized equity market return was at least 12.56 percent or greater.

Figure 10: Realized U.S. equity market returns (1926–2022)[54]



Q. Did you consider another form of the CAPM in your analysis?

A. Yes. I have also considered the results of an ECAPM in estimating the cost of equity for the Company.[55] The ECAPM calculates the product of the adjusted beta coefficient and the market risk premium and applies a weight of 75.00 percent to that result. The model then applies a 25.00 percent weight to the market risk premium without any effect from the beta coefficient. The results of the two calculations are summed, along with the risk-free rate, to produce the ECAPM result, as noted in Equation [5] below:

$$k_e = r_f + 0.75\beta(r_m - r_f) + 0.25(r_m - r_f) \qquad [5]$$

[54] Depicts total annual returns on large company stocks, as reported in the 2023 Kroll SBBI Yearbook**.**
[55] *See, e.g.*, Roger A. Morin, *New Regulatory Finance*, Public Utilities Reports, Inc., at 189 (June 1, 2006).

Where:

k_e = the required market ROE

β = Adjusted Beta coefficient of an individual security

r_f = the risk-free rate of return

r_m = the required return on the market as a whole

The ECAPM addresses the tendency of the "traditional" CAPM to underestimate the cost of equity for companies with low beta coefficients such as regulated utilities. In that regard, the ECAPM is not redundant to the use of adjusted betas in the traditional CAPM, but rather it recognizes the results of academic research indicating that the risk-return relationship is different (in essence, flatter) than estimated by the CAPM, meaning that the CAPM underestimates the "alpha," or the constant return term.[56]

Consistent with my CAPM, my application of the ECAPM uses the forward-looking market risk premium estimates, the three yields on 30-year Treasury securities noted earlier as the risk-free rate, and the current *Bloomberg*, current *Value Line*, and long-term *Value Line* beta coefficients.

Q. What are the results of your CAPM and ECAPM analyses?

A. The results of my CAPM and ECAPM analyses are summarized in Figure 11, as well as presented in Exhibit PAC/407.

[56] *Id*. at 191.

Figure 11: Summary of CAPM and ECAPM Results

	30-Year Treasury Bond Yield		
	Current 30-Day Avg	Near-Term Projected	Longer-Term Projected
CAPM:			
Current *Value Line* Beta	11.73%	11.70%	11.66%
Current Bloomberg Beta	10.95%	10.89%	10.81%
Long-term Avg. *Value Line* Beta	10.59%	10.51%	10.42%
ECAPM:			
Current *Value Line* Beta	11.94%	11.91%	11.88%
Current Bloomberg Beta	11.35%	11.31%	11.25%
Long-term Avg. *Value Line* Beta	11.08%	11.02%	10.95%

C. <u>BYRP Analysis</u>

Q. Please describe the BYRP 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 bondholders. In other words, because returns to equity holders have greater risk than returns to bondholders, equity holders require a higher return for that incremental risk. Thus, risk premium approaches 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 use actual authorized returns for vertically integrated electric utilities as the historical measure of the cost of equity to determine the risk premium.

Q. What is the fundamental relationship between the equity risk premium and interest rates?

A. 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 (*i.e.*, as interest rates increase, the equity risk premium decreases, and vice versa). 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. The analysis presented in Exhibit PAC/410 establishes that relationship using a regression of the risk premium as a function of Treasury bond yields. When the authorized ROEs serve as the measure of required equity returns and the long-term Treasury bond yield is defined as the relevant measure of interest rates, the risk premium is the difference between those two points.[57]

Q. Is the BYRP analysis relevant to investors?

A. Yes. Investors are aware of authorized ROEs 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. As discussed previously, utilities have experienced credit rating downgrades and been subject to a negative market reaction related to the financial effects of a rate case decision that included a below average authorized ROE. Because my BYRP 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 in the current interest rate environment.

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[57] *See e.g.*, S. Keith Berry, *Interest Rate Risk and Utility Risk Premia during 1982-93*, Managerial and Decision Economics, Vol. 19, No. 2 (Mar. 1998) (the author used a similar methodology, including using authorized 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 Shareholder Required Rates of Return*, Financial Management, at 66 (Spring 1986).

Q. What did your BYRP analysis reveal?

A. As shown in Figure 12, from 1980 through November 2023, there was a strong negative relationship between risk premia and interest rates. To estimate that relationship, I have conducted a regression analysis using the following equation:

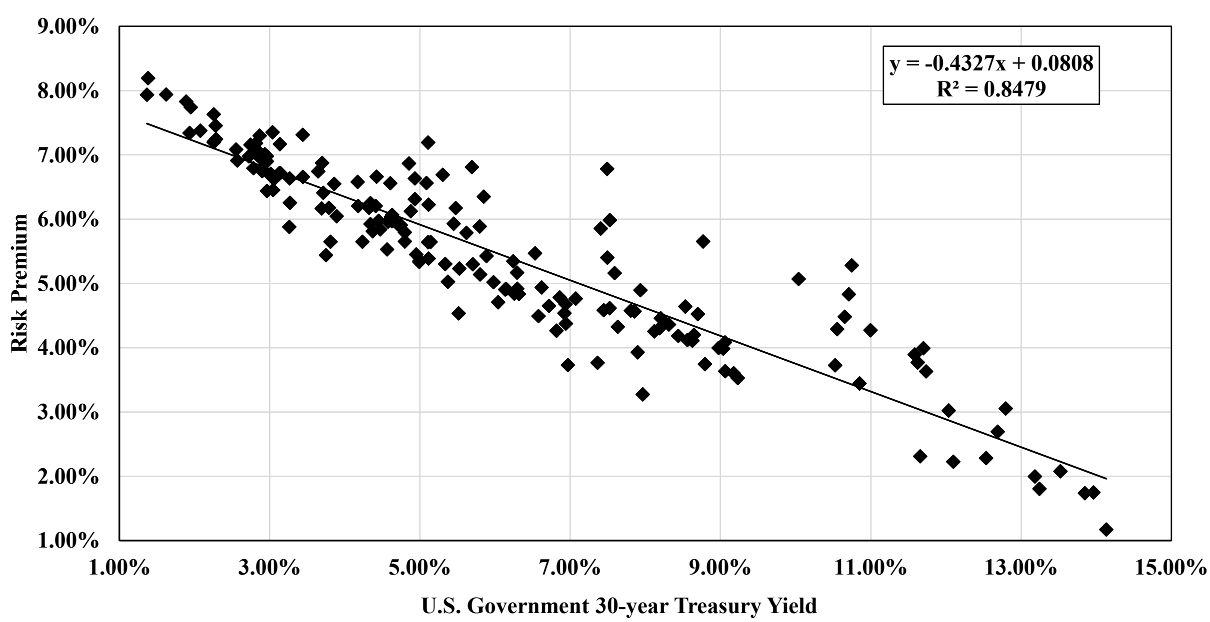
$$RP = a + b(T) \qquad [6]$$

Where:

RP = Risk Premium (difference between authorized ROEs and the yield on 30-year Treasury bonds)
a = intercept term
b = slope term
T = 30-year Treasury bond yield

Data regarding authorized ROEs were derived from all of the vertically-integrated electric utility rate cases over this period as reported by RRA.[58] The equation's coefficients are statistically significant at the 99.00 percent level.

Figure 12: Risk Premium Results



[58] The data was screened to eliminate limited issue rider cases, electric transmission cases, electric distribution-only (*i.e.*, no generation) cases, and cases that were silent with respect to the authorized ROE.

Q. What are the results of your BYRP analysis?

A. Figure 13 presents the results of my BYRP analysis, which is also presented in more detail in Exhibit PAC/410.

Figure 13: BYRP Results

	30-Year Treasury Bond Yield		
	Current 30-Day Avg	Near-Term Projected	Longer-Term Projected
Bond Yield Risk Premium	10.79%	10.62%	10.40%

Q. How did the results of the BYRP analysis inform your recommended ROE for the Company?

A. I have considered the results of the BYRP analysis in my recommended ROE for the Company. As noted, investors consider the authorized ROE for a utility when assessing the risk of that company as compared to utilities of comparable risk operating in other jurisdictions.

VIII. REGULATORY AND BUSINESS RISKS

Q. Do the results of the cost of equity analyses alone provide an appropriate estimate of the cost of equity for the Company?

A. No. These results provide only a range of the appropriate estimate of the Company'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 the Company's risk profile relative to the proxy group.

A. <u>Wildfire Risk</u>

Q. Have equity analysts and credit rating agencies recognized wildfire as a substantial risk to the electric utility sector?

A. Yes. While wildfire risk is not a new threat to utility investors, it has become a much larger focus to both equity investors and credit rating agencies. For example, BofA has stated that wildfire risk has become the top question among all different investor types.[59] In fact, BofA has stated that it sees "the consistent existential risk posed by wildfires outflanking any other factor exposure of a given utility equity."[60] For example, BofA highlighted the catastrophic wildfires in California in 2017-2018 that led to the bankruptcy of PG&E Corporation and its subsidiary Pacific Gas and Electric Company (PG&E) and caused material liabilities that weakened the earnings growth for Southern California Edison (SoCalEd), but noted that the current wildfire risk feels worse given the increased occurrences of wildfires across multiple states, even outside of the traditional wildfire season, and the billions in potential wildfire liabilities currently faced by PacifiCorp in Oregon, Xcel Energy in Colorado, and Hawaiian Electric.[61] A such, a utility's exposure to wildfire risk is expected to be a defining factor for utility valuations:

> Should there be further events, we perceive a risk that the 'new' premium utility will be defined by its exposure to wildfire factors. The first screen is simply geography and FEMA's assessment of wildfire risk, while the second consideration is the legal and regulatory construct under which the utility operates. We anticipate having explicit and

[59] BofA Global Research, US Utilities & IPPs, Wildfire wakeup: what the Hawaiian fires mean for the sector as prudency shifts (Aug. 28, 2023).
[60] BofA Global Research, US Utilities & IPPs, As the leaves fall, preparing for Autumn utility outlook. Micro still has potholes (Sept. 6, 2023).
[61] BofA Global Research, US Utilities & IPPs, Wildfire wakeup: what the Hawaiian fires mean for the sector as prudency shifts (Aug. 28, 2023).

> refreshed plans will become a necessity for any utilities operating in geographies.
>
> *****
>
> On balance, the added wildfire concerns across the west, with their disproportionate manifestation across small- and even mid-caps makes us incrementally cautious on the entire sub-group of utilities.[62]

As further stated by BofA:

> PacifiCorp and Xcel Energy (XEL) are each facing billions in potential wildfire-related liabilities. Hawaiian Electric may not have shareholder value if wholly responsible for the ~$5.4Bn estimated wildfire damage. In the past week, Evergy (EVRG) had a fire caused by its downed poles, and Entergy Corp (ETR) warned of fire hazards. The increased occurrences in multiple states, even outside of the traditional wildfire season has investors of all types on edge.[63]

From the credit rating agency perspective, Moody's has noted that wildfire risk "can reach catastrophic levels at utilities," and that it is difficult to determine which utilities are most at risk given that the recent wildfires in Oregon and Hawaii were in moderate risk zones.[64] S&P has stated that "[d]amages and related costs from physical risks are escalating in North America as regions designated as high-fire risk expand," and that over the past six years, utility credit downgrades directly related to physical risks have increased significantly.[65] Similarly, FitchRatings (Fitch) has noted the higher regulatory risk associated with wildfires, and stated that extreme weather, which includes wildfires, has driven approximately one-quarter of its downgrades in the past 6 years, yet was not a driver of downgrades in the 6 years prior.[66] The most recent

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[62] BofA Global Research, US Utilities & IPPs, As the leaves fall, preparing for Autumn utility outlook. Micro still has potholes (Sept. 6, 2023).
[63] *Id*.
[64] Moody's Investors Service, Breakfast with the Analysts, 58th Annual EEI Financial Conference, at 30 (Nov. 13, 2023).
[65] S&P Global Ratings, A Storm is Brewing: Extreme Weather Events Pressure North American Utilities' Credit Quality, at 1 (Nov. 9, 2023).
[66] Fitch Ratings, *Climate Related Risks in Focus*, 35th Annual Presentation at EEI Financial Conference, at 5, 11 (Nov. 13, 2023).

example is Hawaiian Electric Industries Inc. and its subsidiaries after the catastrophic Maui fires in August 2023 when S&P, Moody's, and Fitch all downgraded to "junk" status in response to the potential wildfire liabilities faced by the utility.[67]

Q. Has wildfire risk been specifically identified as a risk for the Company in Oregon?

A. Yes. Moody's recently noted that wildfire risk has been rising and that wildfires burned more acres in Oregon in 2020 and 2021 than had occurred in the past 20 years.[68] Moody's stated:

> Wildfires are a significant risk for PacifiCorp's service territory in Oregon, Utah, and California. While such wildfire risk has not been on the scale of its California investor-owned utility peers, it still has a substantial impact on its credit profile. Through the third quarter of 2023, the company has so far accrued about $1.9 billion of pretax losses net of the expected insurance recovery for wildfires in Oregon.[69]

Similarly, S&P has recently highlighted PacifiCorp's wildfire risk, noting that it could lead to a credit downgrade:

> We could lower the ratings on PacifiCorp over the next 24 months if the number of claimants and estimated damages concerning its wildfire lawsuits, including the James case, grow significantly such that we anticipate materially weaker leverage, increased business risk, or a weaker degree of group support from its parent. Furthermore, we could also lower ratings if the company's stand-alone FFO to debt consistently weakens to below 13% or if PacifiCorp contributes to a future significant wildfire.[70]

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[67] See, e.g., Fitch downgrades Hawaiian Electric to junk on worries over wildfire exposure, Reuters (Aug. 21, 2023); S&P downgrades Hawaiian Electric to 'B-'as wildfires raise market-access worries, Reuters (Aug. 24, 2023); Moody's downgrades Hawaiian Electric's credit to junk amid Maui wildfire scrutiny, Reuters (Aug. 18, 2023).
[68] Moody's Investors Service, Credit Opinion, PacifiCorp, December 4, 2023, at 5.
[69] *Id*., at 1.
[70] S&P Global Ratings, PacifiCorp Ratings Affirmed Following Archie Creek Settlement; Outlook Negative, at 2 (Dec. 12, 2023).

S&P also stated that it could affirm its rating on PacifiCorp and revise its outlook to stable if the Company were to achieve favorable legal outcomes that limit existing wildfire liabilities the company is not the cause of a future materially significant wildfire.[71]

Q. Is wildfire risk to utilities limited to a few states?

A. No. The Federal Emergency Management Agency (FEMA) publishes a National Risk Index that ranks the wildfire risk by county and census tract in five categories: Very High, Relatively High, Relatively Moderate, Relatively Low, and Very low. Based on FEMA's assessment, wildfire risk is much more broad than a few states, with the risk identified primarily as west of the Mississippi River, Hawaii, Florida, and the southeastern coast of the U.S.[72]

Q. Have you conducted any analysis to evaluate the wildfire risk in Oregon as compared to the jurisdictions in which the companies in the proxy group operate?

A. Yes. Based on FEMA's rankings of the Expected Annual Loss associated with wildfire for each state, I have conducted an analysis to compare the wildfire risk of Oregon to the jurisdictions in which the utility operating subsidiaries of the companies in the proxy group operate. Specifically, I have applied a numeric ranking system to the FEMA rankings with "Very Low" assigned the lowest ranking (*i.e.*, a "1") and "Very High" assigned the highest ranking (*i.e.*, a "5"). As shown on Exhibit PAC/411, Oregon is ranked "Relatively Moderate" (*i.e.*, a "3"). This ranking for Oregon indicates a higher risk for the Company relative to the proxy group, which

[71] *Id*.
[72] FEMA, National Risk Index; https://hazards.fema.gov/nri/map# (wildfire risk by census tract).

has an average ranking of between "Relatively Low" and "Relatively Moderate" (*i.e.*, a "2.14").

Q. What are your conclusions regarding the effect of wildfire risk on the Company in Oregon?

A. Wildfire risk presents one of the most significant business, operational, and financial threats for utilities in states subject to such risks. Oregon has relatively greater wildfire risk as compared to the proxy group utilities, and it is clear that equity investors and credit rating agencies are reflecting the incremental risk for companies that have been affected by wildfire exposure and that the electric utility sector overall has increased risk related to this threat. The capital costs associated with wildfire mitigation can be significant and continue over many years, thus making the timeliness of cost recovery important. Absent meaningful regulatory support for the utilities in the states subject to substantial potential losses from wildfires, the investor-required return increases significantly due to the higher risk of wildfire exposure. Addressing this risk in a timely manner should be a top regulatory priority in order to provide the Company with the ability to access capital on reasonable terms, and make the capital investments needed going forward.

B. <u>Capital Expenditures</u>

Q. Please summarize the Company's capital expenditure requirements.

A. The Company's current projection of capital expenditures for 2024 through 2026 totals approximately $10.6 billion, which represents approximately 43 percent of the Company's approximate $24.4 billion in net utility plant as of December 31, 2022.[73]

[73] Data provided by the Company.

Q. How do the Company's capital expenditures compare to those of the proxy group?

A. As shown on Exhibit PAC/412, I have calculated the ratio of expected capital expenditures to net utility plant for the Company and each of the companies in the proxy group by dividing each company's projected capital expenditures for the period from 2024 through 2026 by its total net utility plant as of December 31, 2022. As shown, the Company's ratio of capital expenditures as a percentage of net utility plant is approximately 139 percent of the median for the proxy group companies.

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. 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.[74]

Recently, S&P evaluated the capital expenditure trends in the utility sector, noting that the balance between operating with negative discretionary cash flow from operations offset by reliable access to capital markets for financing may be tested through ever-increasing capital expenditure requirements as a result of the transformation of the energy sector through the focus on low/no carbon generation, electrification, and the replacement of aging infrastructure:

> Some companies have been unable to support financial metrics consistent with former ratings as their discretionary cash flow deteriorated. This trend was a significant contributor to the sector seeing the median rating decline to 'BBB+' from 'A-' for the first time in 2022. What is less clear is whether or not management teams will take steps to forestall another step down in credit quality as high capital outlays persist. So far in 2023, we have not seen evidence that equity issuance is keeping pace with debt issuance to fill ever-deepening discretionary cash flow shortfalls, but time will tell.
>
> …..
>
> Despite the improvement in the economic outlook, we expect inflation, high interest rates, higher capital spending, and the strategic decision by many companies to operate with only minimal financial cushion from their downgrade thresholds to continue to pressure the industry's credit quality. We are cautious about the durability of the current stable ratings outlook given persistently high capital spending that now supports a trend of deterioration in discretionary cash flow. Without a commensurate focus on balance sheet preservation through equity support of discretionary cash flow deficits, limited financial cushions

[74] S&P Global Ratings, Assessing U.S. Investor-Owned Utility Regulatory Environments, at 7 (Aug. 10, 2016).

> could give rise to another round of negative rating actions. The question then comes back to management priorities and financial policy decisions, or utilities may be faced with another step down in the median ratings. [75]

Therefore, to the extent that the Company's rates do not continue to reasonably permit the recovery its prudently-incurred capital investments on a timely basis, the Company would face increased recovery risk and thus increased pressure on its credit metrics.

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

A. Yes. PacifiCorp is authorized to separately file to recover capital costs to construct or otherwise acquire renewable generation facilities and the associated transmission between rate cases through the Renewable Adjustment Clause. The Company also has wildfire mitigation cost recovery through its Wildfire Mitigation Plan Automatic Adjustment Clause associated with its Wildfire Mitigation Plan. The Company does not have cost recovery mechanisms for capital expenditures related to its transmission and distribution system unrelated to wildfire mitigation or non-renewable generation resources.

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

A. The Company's capital expenditure requirements as a percentage of net utility plant are significant and are expected to continue over the next few years. While the Company does have capital cost recovery for certain renewable generation-related

[75] S&P Global Ratings, Record CapEx Fuels Growth Along With Credit Risk For North American Investor-Owned Utilities, at 5, 7-8 (Sept. 12, 2023).

expenditures and wildfire-related expenditures, it does not for the recovery of its transmission and distribution expenditures unrelated to wildfire mitigation or non-renewable generation resources, thus timely recovery of a substantial portion of the Company's capital expenditures are not provided for between rate cases.

C. <u>Regulatory Risks</u>

Q. How does 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 commissions 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. The Company 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. Do credit rating agencies consider regulatory risk in establishing a company's credit rating?

A. Yes. 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.[76]

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

[76] Moody's Investors Service, Rating Methodology: Regulated Electric and Gas Utilities, at 4 (June 23, 2017).

utility operates."[77] S&P identifies four specific factors that it uses to assess the credit implications of the regulatory jurisdictions of investor-owned regulated utilities: (1) regulatory stability; (2) tariff-setting procedures and design; (3) financial stability; and (4) regulatory independence and insulation.[78]

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."[79] 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."[80]

[77] Standard & Poor's Global Ratings, U.S. and Canadian Regulatory Jurisdictions Support Utilities' Credit Quality—But Some More So Than Others, at 2 (June 25, 2018).
[78] *Id*., at 1.
[79] Moody's Investors Service, Rating Methodology: Regulated Electric and Gas Utilities, at 6 (June 23, 2017).
[80] *Id*.

Q. Have you conducted any analysis of the regulatory framework in Oregon 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 convention for ratemaking (*i.e.*, forecast vs. historical test year); (3) use of rate design and/or other mechanisms that mitigate volumetric risk and stabilize revenue; and (4) prevalence of capital cost recovery between rate cases. The results of my regulatory risk assessment are shown in Exhibit PAC/413 and are summarized below.

- *Fuel Cost Recovery*: The Company 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 has an asymmetrical deadband whereby the Company absorbs variances in fuel costs that are up to $30 million more than projected and $15 million less than projected. The PCAM also has a sharing mechanism whereby any power cost variance outside the deadband is shared 90 percent by customers and 10 percent by the Company if it earns within plus or minus 100 basis points of its authorized ROE.[81] However, if the Company is earning within this range of its authorized ROE, there is no power cost adjustment for that year. Finally, amortization of deferred amounts in any one year under the PCAM is limited to 6 percent of the Company's revenues in the preceding calendar year.[82]

As a result, the PCAM does not fully mitigate the Company's risk of recovery of its fuel and purchased power costs, which is important to investors given that fuel and purchased power costs typically account for 50–60 percent of the total operating costs for a regulated utility. Moreover, there are only nine states (*i.e.*, Arizona,

[81] Docket No. UE 374, Order No. 20-476 at 30.
[82] 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).

Hawaii, Idaho, Missouri, Montana, Oregon, Vermont, Washington, and Wyoming) that have fuel cost recovery mechanisms with sharing bands. The remaining 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.

- *Test Year Convention:* The Company relies on a historical test year for ratemaking purposes. As shown in Exhibit PAC/413, approximately 55 percent of the operating utility subsidiaries of the proxy group companies provide service in jurisdictions that use a historical test year. Forecast test years result in more prompt recovery of incurred costs and thus mitigates the regulatory lag associated with historical test years. As Lowry, Hovde, Getachew, and Makos (2010) explain:

> This report provides an in depth discussion of the test year issue. It includes the results of empirical research which explores why the unit costs of electric IOUs are rising and shows that utilities operating under forward test years realize higher returns on capital and have credit ratings that are materially better than those of utilities operating under historical test years. *The research suggests that shifting to a future test year is a prime strategy for rebuilding utility credit ratings as insurance against an uncertain future*.[83]

- *Revenue Stabilization/Non-Volumetric Rate Design*: The Company does not have protection against volumetric risk in Oregon. In contrast, as shown in Exhibit PAC/413, approximately 60 percent of the utility operating subsidiaries of the proxy group companies have some form of revenue stabilization through either decoupling, formula-based rates, and/or straight-fixed variable rate design that allow them to break the link between customer usage and revenues.

- *Capital Cost Recovery*: As discussed, the Company has capital cost recovery mechanisms for the construction of new renewable generation and associated transmission, as well as dam removal and wildfire mitigation expenditures. Similarly, as shown in Exhibit PAC/413, approximately 67 percent of the

[83] Mark Newton Lowry, David Hovde, Lullit Getachew, and Matt Makos. *Forward Test Years for US Electric Utilities,*" at 1, (Prepared for the Edison Electric Institute, Aug. 2010); emphasis added.

operating utility subsidiaries of the proxy group companies also have some form of capital cost recovery allowing for the recovery of capital investments placed into service between rate cases.

Q. Have you conducted any additional analyses to evaluate the regulatory environment in Oregon as compared to the jurisdictions in which the companies in the proxy group operate?

A. Yes, I have conducted two additional analyses to compare the regulatory framework of Oregon to the jurisdictions in which the companies in the proxy group operate. Specifically, I considered two different rankings: (1) the RRA ranking of regulatory jurisdictions; and (2) S&P's ranking of the credit supportiveness of regulatory jurisdictions.

Q. How does RRA evaluate the regulatory environment in each jurisdiction?

A. RRA evaluates the regulatory environment from an investor perspective, considering the relative regulatory risk associated with ownership of securities issued by the companies that are regulated in each jurisdiction. RRA considers several factors that affect the regulatory process including gubernatorial, legislative and court activity, rate case decisions and other regulatory decisions, and information obtained through contact with commissioners, staff, utilities, and government outreach.

Q. How do you use the RRA ratings to compare the regulatory jurisdictions of the proxy group companies with the Company's regulatory jurisdiction?

A. RRA assigns a ranking for each regulatory jurisdiction as "Above Average", "Average" or "Below Average", and then within each of those categories, a numeric ranking from 1 to 3. Thus, there are a total of nine RRA rankings, with the rankings for each jurisdiction ranging from "Above Average/1", which is considered the most supportive, to "Below Average/3," which is the least supportive. I have applied a numeric ranking system to the RRA rankings with "Above Average/1" assigned the highest ranking (*i.e.*, a "1") and "Below Average/3" assigned the lowest ranking (*i.e.*, a "9").

As shown on Exhibit PAC/414, the Oregon jurisdictional ranking is "Average / 2" (*i.e.*, a "5"), which is below the proxy group average ranking of between "Average/1" and "Average/2" (*i.e.*, a "4.69").

Q. How do you conduct your analysis of the S&P credit supportiveness ranking?

A. For credit supportiveness, S&P classifies each regulatory jurisdiction into five categories that range from "Most Credit Supportive" down to "Credit Supportive." My analysis of the credit supportiveness of the regulatory jurisdictions in which the proxy companies operate as compared to the Company's regulatory jurisdiction is similar to the analysis of the RRA overall regulatory ranking discussed above. Specifically, I have assigned a numerical ranking to each category, from Most Credit Supportive (*i.e.*, a "1") to Credit Supportive (*i.e.*, a "5").

As shown on Exhibit PAC/415, similar to the RRA regulatory rankings discussed above, S&P ranks Oregon as "4", which is below the proxy group average ranking of "2.53".

Q. Is it important that the Commission consider how the ROE to be authorized for the Company in this proceeding compares to other comparable utilities?

A. Yes. As discussed previously, the Company must compete for discretionary capital within the PacifiCorp corporate structure, as well as within the BHE corporate structure, which must in turn compete for capital with other utilities and businesses. Investors consider the business and financial risks of the Company relative to other comparable investments. Therefore, the Commission should consider how the authorized ROE for the Company in this proceeding compares to the ROEs authorized for other vertically-integrated utilities, assess that comparison relative to the changes in capital market conditions, as well as consider the specific business and regulatory risks of the Company relative to the proxy group, so that the Company's future access to capital is not negatively impacted. 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. As noted previously, there are various examples of utilities that have experienced a credit rating downgrade and/or a negative market response related to the financial effects of a rate decision.

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

A. 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. Based on my analysis, the Company's regulatory risk and the ability to timely recover its prudently incurred costs is moderately higher relative to the operating utilities of the proxy group given the Company's risk associated with fuel cost recovery and the lack of revenue stabilization. For these reasons, I conclude that the Company has greater than average regulatory risk when compared to the proxy group.

IX. CAPITAL STRUCTURE

Q. Is the capital structure of the Company an important consideration in the determination of the appropriate ROE?

A. Yes. The equity ratio is the primary indicator of financial risk for a regulated utility. All else equal, a higher debt ratio increases the risk to investors, which has been recognized by the Commission.[84] Specifically, 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, whose claim on the cash flow of the Company is secondary to debt holders. Therefore, the greater the debt service requirement, the less cash flow is available for common equity holders.

Q. What is the Company's proposed capital structure?

A. As discussed in the direct testimony of Company witness Kobliha, PacifiCorp is proposing a capital structure that is composed of 50.00 percent common equity and 50.00 percent long-term debt.

Q. Does the Company's proposed capital structure differ from its actual capital structure?

A. Yes. As discussed in the testimony of Company witness Kobliha, the Company's actual capital structure has been affected by recent significant one-time events that has resulted in a more highly leveraged capital structure than is typically relied upon to finance the business. In the Company's last rate proceeding, the equity ratio that

[84] *See, e.g.,* Docket No. UE 374, Order No. 20-476 at 31 (fn 135).

was agreed to by the parties was composed of 50 percent equity and 50 percent long-term debt, which is consistent with the proposed equity ratio in this proceeding.

Q. Did you conduct any analysis to determine if the requested equity ratio was reasonable?

A. Yes. I compared the Company's proposed capital structure relative to the actual capital structures of the utility operating subsidiaries of the companies in the proxy group. The cost of equity is estimated based on the return that is derived from companies in the proxy group that are deemed to be comparable in risk to the Company; however, those companies must be publicly-traded in order to apply the cost of equity models. The operating utility subsidiaries of the proxy group companies are most risk-comparable to the Company, and thus it is reasonable to look to the average capital structure of the operating utilities of the proxy group to benchmark the equity ratios for the Company.

Specifically, I have calculated the average proportion of common equity, long-term debt, and preferred equity for the most recent three years for each of the utility operating subsidiaries of the proxy group companies. As shown in Exhibit PAC/416, the mean and median equity ratios for the utility operating subsidiaries of the proxy group are 52.89 percent and 52.77 percent respectively, which are significantly higher than the Company's proposed equity ratio percent.

Q. Are there other factors to be considered in setting the Company's capital structure?

A. Yes, there are other factors that should be considered in setting the Company's capital structure, namely the challenges that the credit rating agencies have highlighted as placing pressure on the credit metrics for utilities.

For example, while Moody's recently revised its outlook for the utility sector from "negative" to "stable", Moody's continues to note that high interest rates and increased capital spending will place pressure on credit metrics. Thus, Moody's highlights constructive regulatory outcomes that promote timely cost recovery as a key factor in supporting utility credit quality.[85]

Likewise, while S&P also recently revised its outlook for the industry from negative to stable, S&P continues to see significant risks over the near-term for the industry as a result of inflation and increased levels of capital spending. Specifically, S&P noted:

> Despite the improvement in economic data, we expect inflation, rising interest rates, higher capital spending, and the strategic decision by many companies to operate with only minimal financial cushion from their downgrade thresholds to continue to pressure the industry's credit quality. Throughout 2022 and so far in 2023, the Federal Reserve has consistently raised interest rates to reduce the pace of inflation. While these actions appear to have had a positive effect on slowing inflation, there's still been a modest weakening in the industry's financial measures because of inflation and rising interest rates. An environment of continuously rising costs tends to weaken the industry's financial measures because of the timing difference between when the higher costs are incurred and when they are ultimately recovered from ratepayers.[86]

S&P has also recently concluded:

[85] Moody's Investors Service, Outlook turns stable on low prices and credit-supportive regulation. (Sept. 7, 2023).
[86] S&P Global Ratings, The Outlook for North American Regulated Utilities Turns Stable, at 8 (May 18, 2023).

> The confluence of higher operating costs due to rising inflation, higher interest rates, storm restoration costs, increasing capital spending, and the recovery of previously deferred higher commodity costs, has resulted in growing rate case filings and increased rate rider recovery requests from state regulators. We expect to closely monitor the industry's ability to not just recover these rising costs but to do so in such a manner that minimizes the regulatory lag. However, given the impact of these higher costs to the customer bill, the industry's ability to effectively manage regulatory risk could become increasingly challenging, possibly pressuring its credit quality.[87]

Fitch has stated that it is maintaining a "deteriorating outlook" on the U.S. utility sector in 2024 based on elevated capital spending and continuing higher interest rates that place pressure on credit metrics. Fitch noted that bill affordability will remain a major issue for the industry that could affect future regulatory outcomes, and that while it expects authorized ROEs to start trending up with the increase in interest rates, albeit with a lag, given the uncertain macroeconomic environment and bill pressure on customers, the lag could be longer than in previous cycles.[88]

In addition to the specific concerns raised for PacifiCorp, discussed previously and in more detail in the direct testimony of Company witness Kobliha, the credit ratings agencies' continued concerns over the negative effects of inflation and increased capital expenditures underscore the importance of maintaining adequate cash flow metrics for the industry as a whole, and PacifiCorp in particular in the context of this proceeding.

[87] S&P Global Ratings, Regulatory Friction Is Constraining Cost Recovery For North American Investor-Owned Utilities, at 8 (Nov. 6, 2023).
[88] Fitch Ratings, *North American Utilities, Power & Gas Outlook,* S&P Market Intelligence (Nov. 13, 2023).

Q. Will the capital structure and ROE authorized in this proceeding affect the Company's access to capital at reasonable rates?

A. Yes. As discussed in the testimony of Company witness Kobliha, the Company's credit metrics have fallen below the thresholds that are acceptable for its current rating. The level of earnings authorized by the Commission will directly affect the Company's ability to fund its operations with internally-generated funds.

X. CONCLUSIONS AND RECOMMENDATIONS

Q. What is your conclusion regarding a fair ROE for the Company?

A. Based on the various quantitative analyses summarized in Figure 14, a reasonable range for the Company's ROE is from 10.25 percent to 11.25 percent. Considering the qualitative analyses presented in my direct testimony, and the Company's regulatory, business, and financial risk relative to the proxy group, I conclude that the Company has significantly greater risk than the proxy group companies and therefore an ROE at the higher end of the range of results is reasonable. However, the Company is requesting a more moderate return of 10.3 percent, which, as discussed in the testimony of Company witness McVee, balances the impact on customers with the prevailing market conditions that support a higher ROE and the Company's increased need to access capital at a reasonable costs in light of the escalating utility risks as discussed by Company witnesses Crane, Kobliha, Steward, and Coleman.

Figure 14: Summary of Analytical Results

Constant Growth DCF

	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Mean Results:			
30-Day Avg. Stock Price	9.08%	10.31%	11.43%
90-Day Avg. Stock Price	9.02%	10.25%	11.37%
180-Day Avg. Stock Price	8.83%	10.06%	11.17%
Average	8.98%	10.21%	11.32%
Median Results:			
30-Day Avg. Stock Price	9.37%	10.10%	11.33%
90-Day Avg. Stock Price	9.17%	10.13%	11.30%
180-Day Avg. Stock Price	8.90%	10.01%	11.14%
Average	9.14%	10.08%	11.26%

Multi-Stage DCF

	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Mean Results:			
30-Day Avg. Stock Price	9.94%	10.27%	10.60%
90-Day Avg. Stock Price	9.88%	10.21%	10.53%
180-Day Avg. Stock Price	9.68%	9.99%	10.31%
Average	9.83%	10.16%	10.48%
Median Results:			
30-Day Avg. Stock Price	9.87%	10.45%	10.75%
90-Day Avg. Stock Price	9.73%	10.28%	10.68%
180-Day Avg. Stock Price	9.65%	10.02%	10.43%
Average	9.75%	10.25%	10.62%

CAPM / ECAPM / Bond Yield Risk Premium

	30-Year Treasury Bond Yield		
	Current 30-Day Avg	Near-Term Projected	Longer-Term Projected
CAPM:			
Current *Value Line* Beta	11.73%	11.70%	11.66%
Current Bloomberg Beta	10.95%	10.89%	10.81%
Long-term Avg. *Value Line* Beta	10.59%	10.51%	10.42%
ECAPM:			
Current *Value Line* Beta	11.94%	11.91%	11.88%
Current Bloomberg Beta	11.35%	11.31%	11.25%
Long-term Avg. *Value Line* Beta	11.08%	11.02%	10.95%
Bond Yield Risk Premium	10.79%	10.62%	10.40%

Q. What is your conclusion with respect to the Company's proposed capital structure?

A. My conclusion is that the Company's proposal to establish a capital structure consisting of 50.00 percent common equity and 50.00 percent long-term debt is necessary to increase its credit metrics to the ranges established by the credit rating agencies for the Company's current credit ratings. Further, the proposed capitalization is conservative when compared to the proxy group companies, as the equity ratio proposed by the Company is well below the mean or median equity ratio of the utility operating companies of the proxy group. Finally, maintaining the Company's credit ratings and the ability to access capital on reasonable terms, particularly at a time when the Company has significant capital requirements, provides benefits to customers over the long-term. Therefore, I conclude that the Company's proposed capital structure is reasonable and should be approved.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 433
Exhibit PAC/401
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

February 2024

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 and water utility sectors, including valuation of regulated and unregulated utility assets, cost of capital, 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

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 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.

- Conducted a strategic review of the acquisition of nuclear generation assets. Review included the evaluation of the operating costs of the facilities and the long-term liabilities associated with the assets including the decommissioning of the assets.
- 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.
- Conducted a valuation of regulated utility assets for the fair value rate base estimate used in electric rate proceedings in Indiana.
- 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 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.

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BULKLEY TESTIMONY LISTING

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Arizona Corporation Commission				
UNS Electric	11/22	UNS Electric	Docket No. E-04204A-15-0251	Return on Equity
Tucson Electric Power Company	6/22	Tucson Electric Power Company	Docket No. G-01933A-22-0107	Return on Equity
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
Arkansas Oklahoma Gas Corporation	10/13	Arkansas Oklahoma Gas Corporation	Docket No. 13-078-U	Return on Equity
California Public Utilities Commission				
PacifiCorp, d/b/a Pacific Power	5/22	PacifiCorp, d/b/a Pacific Power	Docket No. A-22-05-006	Return on Equity
San Jose Water Company	05/21	San Jose Water Company	A2105004	Return on Equity

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SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Colorado Public Utilities Commission				
Public Service Company of Colorado	01/24	Public Service Company of Colorado	Docket No. 24AL-___G	Return on Equity
Public Service Company of Colorado	11/22	Public Service Company of Colorado	Docket No. 22AL-0530E	Return on Equity
Public Service Company of Colorado	01/22	Public Service Company of Colorado	Docket No. 22AL-0046G	Return on Equity
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				
The Southern Connecticut Gas Company	11/23	The Southern Connecticut Gas Company	Docket No. 23-11-02	Return on Equity
Connecticut Natural Gas Corporation	11/23	Connecticut Natural Gas Corporation	Docket No. 23-11-02	Return on Equity
Connecticut Water Company	10/23	Connecticut Water Company	Docket No. 23-08-32	Return on Equity
United Illuminating	09/22	United Illuminating	Docket No. 22-08-08	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
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
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				
Sea Robin Pipeline	12/22	Sea Robin Pipeline	Docket No. RP22-___	Return on Equity
Northern Natural Gas Company	07/22	Northern Natural Gas Company	Docket No. RP22-___	Return on Equity
Transwestern Pipeline Company, LLC	07/22	Transwestern Pipeline Company, LLC	Docket No. RP22-___	Return on Equity
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
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				
Intermountain Gas Co	12/22	Intermountain Gas Co	C-INT-G-22-07	Return on Equity
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				
Peoples Gas Light & Coke Company	01/23	Peoples Gas Light & Coke Company	D-23-0069	Return on Equity
North Shore Gas Company	01/23	North Shore Gas Company	D-23-0068	Return on Equity
Illinois American Water	02/22	Illinois American Water	Docket No. 22-0210	Return on Equity
North Shore Gas Company	02/21	North Shore Gas Company	No. 20-0810	Return on Equity
Indiana Utility Regulatory Commission				
Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South	12/23	Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South	IURC Cause No. 45990	Return on Equity
Indiana Michigan Power Co.	08/23	Indiana Michigan Power Co.	IURC Cause No. 45933	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Indiana American Water Company	03/23	Indiana and Michigan American Water Company	IURC Cause No. 45870	Return on Equity
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				

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
MidAmerican Energy Company	06/23	MidAmerican Energy Company	Docket No. RPU-2023-___	Return on Equity
MidAmerican Energy Company	01/22	MidAmerican Energy Company	Docket No. RPU-2022-0001	Return on Equity
Iowa-American Water Company	08/20	Iowa-American Water Company	Docket No. RPU-2020-0001	Return on Equity
Kansas Corporation Commission				
Evergy Kansas	04/23	Evergy Kansas	**Docket No. 23-_____-_____-RTS**	Return on Equity
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	06/23	Kentucky American Water Company	Docket No. 2023-____	Return on Equity
Kentucky American Water Company	11/18	Kentucky American Water Company	Docket No. 2018-00358	Return on Equity
Maine Public Utilities Commission				
Central Maine Power	08/22	Central Maine Power	Docket No. 2022-00152	Return on Equity
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
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				
Massachusetts Electric Company Nantucket Electric Company d/b/a National Grid	11/23	Massachusetts Electric Company Nantucket Electric Company d/b/a National Grid	DPU 23-150	Return on Equity
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				
Indiana Michigan Power Co.	09/23	Indiana Michigan Power Co.	Case No. U-21461	Return on Equity
Michigan Gas Utilities Corporation	03/23	Michigan Gas Utilities Corporation	Case No. U-21366	Return on Equity
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
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Covert Township	07/14	New Covert Generating Co., LLC.	Docket No. 399578	Valuation of Electric Generation Assets
Minnesota Public Utilities Commission				
ALLETE, Inc. d/b/a Minnesota Power	11/23	Allete, Inc. d/b/a Minnesota Power	D-E-015/GR-23-155	Return on Equity
CenterPoint Energy Resources	11/23	CenterPoint Energy Resources	D-G-008/GR-23-173	Return on Equity
Minnesota Energy Resources Corporation	11/22	Minnesota Energy Resources Corporation	Docket No. G011/GR-22-504	Return on Equity
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				

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Ameren Missouri	08/22	Ameren Missouri	File No. ER-2022-0337	Return on Equity
Missouri American Water Company	07/22	Missouri American Water Company	Case No. WR-2022-0303 Case No. SR-2022-0304	Return on Equity
Evergy Missouri West	1/22	Evergy Missouri West	File No. ER-2022-0130	Return on Equity
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.	11/22	Montana-Dakota Utilities Co.	D2022.11.099	Return on Equity
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				

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Liberty Utilities (EnergyNorth Natural Gas)	07/23	Liberty Utilities (EnergyNorth Natural Gas)	Docket No. DG 23-067	Return on Equity
Liberty Utilities (Granite State Electric)	05/23	Liberty Utilities (Granite State Electric)	Docket No. DE 23-039	Return on Equity
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				
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	11/23	Public Service Electric and Gas Company	ER23120924 GR23120925	Return on Equity
New Jersey American Water Company, Inc.	01/22	New Jersey American Water Company, Inc.	WR22010019	Return on Equity
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

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SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
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
New York State Department of Public Service				
Liberty Utilities (New York Water)	5/23	Liberty Utilities (New York Water)	Case 23-W-0235	Return on Equity
New York State Electric and Gas Company Rochester Gas and Electric	05/22	New York State Electric and Gas Company Rochester Gas and Electric	22-E-0317 22-G-0318 22-E-0319 22-G-0320	Return on Equity
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
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
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				

Brattle

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Otter Tail Power Company	11/23	Otter Tail Power Company	Case No. PU-23-___	Return on Equity
Montana-Dakota Utilities Co.	11/23	Montana-Dakota Utilities Co.	Case No. PU-23-___	Return on Equity
Montana-Dakota Utilities Co.	05/22	Montana-Dakota Utilities Co.	C-PU-22-194	Return on Equity
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				
Oklahoma Gas & Electric	12/23	Oklahoma Gas & Electric	Cause No. PUD2023-000087	Return on Equity
Oklahoma Gas & Electric	12/21	Oklahoma Gas & Electric	Cause No. PUD 202100164	Return on Equity
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	03/22	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-399	Return on Equity
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.	11/23	Pennsylvania-American Water Company	Docket No. R-2023-3043189 (water) Docket No. R-2023-3043190 (wastewater)	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
American Water Works Company Inc.	04/22	Pennsylvania-American Water Company	Docket No. R-2020-3031672 (water) Docket No. R-2020-3031673 (wastewater)	Return on Equity
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				
MidAmerican Energy Company	05/22	MidAmerican Energy Company	D-NG22-005	Return on Equity
Northern States Power Company	06/14	Northern States Power Company	Docket No. EL14-058	Return on Equity
Texas Public Utility Commission				
Entergy Texas, Inc.	07/22	Entergy Texas, Inc.	D-53719	Return on Equity
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
Texas Railroad Commission				
CenterPoint Energy Entex and CenterPoint Energy Texas Gas	10/23	CenterPoint Energy Entex and CenterPoint Energy Texas Gas	2023 Texas Division Rate Case Case No. OS-23-00015513	Return on Equity
Utah Public Service Commission				

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
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.	11/23	Virginia American Water Company, Inc.	Docket No. PUR-2023-00194	Return on Equity
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				
PacifiCorp d/b/a Pacific Power & Light	03/23	PacifiCorp d/b/a Pacific Power & Light	Docket No. UE-230172	Return on Equity
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	05/23	West Virginia American Water Company	Case No. 23-0383-W-42T	Return on Equity
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 Power and Light	05/23	Wisconsin Power and Light	Docket No. 6680-UR-124	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Wisconsin Electric Power Company and Wisconsin Gas LLC	04/22	Wisconsin Electric Power Company and Wisconsin Gas LLC	Docket No. 05-UR-110	Return on Equity
Wisconsin Public Service Corp.	04/22	Wisconsin Public Service Corp.	6690-UR-127	Return on Equity
Alliant Energy		Alliant Energy		Return on Equity
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
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	02/23	PacifiCorp d/b/a Rocky Mountain Power	Docket No. 20000-633-ER-23	Return on Equity
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

Docket No. UE 433
Exhibit PAC/402
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Ann E. Bulkley

Summary of Results

February 2024

COST OF EQUITY ANALYSES
SUMMARY OF RESULTS

Constant Growth DCF

	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Mean Results:			
30-Day Avg. Stock Price	9.08%	10.31%	11.43%
90-Day Avg. Stock Price	9.02%	10.25%	11.37%
180-Day Avg. Stock Price	8.83%	10.06%	11.17%
Average	8.98%	10.21%	11.32%
Median Results:			
30-Day Avg. Stock Price	9.37%	10.10%	11.33%
90-Day Avg. Stock Price	9.17%	10.13%	11.30%
180-Day Avg. Stock Price	8.90%	10.01%	11.14%
Average	9.14%	10.08%	11.26%

Multi-Stage DCF

	Minimum Growth Rate	Average Growth Rate	Maximum Growth Rate
Mean Results:			
30-Day Avg. Stock Price	9.94%	10.27%	10.60%
90-Day Avg. Stock Price	9.88%	10.21%	10.53%
180-Day Avg. Stock Price	9.68%	9.99%	10.31%
Average	9.83%	10.16%	10.48%
Median Results:			
30-Day Avg. Stock Price	9.87%	10.45%	10.75%
90-Day Avg. Stock Price	9.73%	10.28%	10.68%
180-Day Avg. Stock Price	9.65%	10.02%	10.43%
Average	9.75%	10.25%	10.62%

CAPM / ECAPM / Bond Yield Risk Premium

	30-Year Treasury Bond Yield		
	Current 30-Day Avg	Near-Term Projected	Longer-Term Projected
CAPM:			
Current *Value Line* Beta	11.73%	11.70%	11.66%
Current Bloomberg Beta	10.95%	10.89%	10.81%
Long-term Avg. *Value Line* Beta	10.59%	10.51%	10.42%
ECAPM:			
Current *Value Line* Beta	11.94%	11.91%	11.88%
Current Bloomberg Beta	11.35%	11.31%	11.25%
Long-term Avg. *Value Line* Beta	11.08%	11.02%	10.95%
Bond Yield Risk Premium	10.79%	10.62%	10.40%

Docket No. UE 433
Exhibit PAC/403
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Ann E. Bulkley

Proxy Group Selection

February 2024

PROXY GROUP SCREENING DATA AND RESULTS - PRELIMINARY PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[9]
Company	Ticker	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	% Company-Owned Generation > 40%	% Regulated Operating Income > 60%	Announced Merger
ALLETE, Inc.	ALE	Yes	BBB	Yes	Yes	Yes	43.27%	100.56%	No
Alliant Energy Corporation	LNT	Yes	A-	Yes	Yes	Yes	72.75%	87.90%	No
Ameren Corporation	AEE	Yes	BBB+	Yes	Yes	Yes	75.34%	84.57%	No
American Electric Power Company, Inc.	AEP	Yes	A-	Yes	Yes	Yes	51.62%	97.34%	No
Avista Corporation	AVA	Yes	BBB	Yes	Yes	Yes	59.47%	73.85%	No
CMS Energy Corporation	CMS	Yes	BBB+	Yes	Yes	Yes	42.50%	65.48%	No
Duke Energy Corporation	DUK	Yes	BBB+	Yes	Yes	Yes	81.53%	91.02%	No
Entergy Corporation	ETR	Yes	BBB+	Yes	Yes	Yes	71.43%	98.21%	No
Evergy, Inc.	EVRG	Yes	BBB+	Yes	Yes	Yes	62.14%	100.00%	No
IDACORP, Inc.	IDA	Yes	BBB	Yes	Yes	Yes	65.35%	99.91%	No
NextEra Energy, Inc.	NEE	Yes	A-	Yes	Yes	Yes	96.40%	92.16%	No
NorthWestern Corporation	NWE	Yes	BBB	Yes	Yes	Yes	55.82%	84.28%	No
OGE Energy Corporation	OGE	Yes	BBB+	Yes	Yes	Yes	50.65%	100.00%	No
Pinnacle West Capital Corporation	PNW	Yes	BBB+	Yes	Yes	Yes	76.09%	100.00%	No
Portland General Electric Company	POR	Yes	BBB+	Yes	Yes	Yes	54.88%	100.00%	No
Southern Company	SO	Yes	BBB+	Yes	Yes	Yes	76.85%	75.31%	No
Xcel Energy Inc.	XEL	Yes	A-	Yes	Yes	Yes	57.97%	86.47%	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] Source: S&P Capital IQ Pro
[6] Source: S&P Capital IQ Pro
[7] Source: Form 10-K's for 2021, 2020, and 2019
[8] Source: Form 10-K's for 2021, 2020, and 2019
[9] Source: S&P Capital IQ Pro Financial News Releases
[10] OTTR: 2021 Operating Income Data was excluded from the three year average since, as noted by Otter Tail, 2021 operating income was impacted by the plastics segment that is not expected to continue over the long-term term.

Docket No. UE 433
Exhibit PAC/404
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

February 2024

30-DAY CONSTANT GROWTH DCF

Company		[1] Annualized Dividend	[2] Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Value Line Projected EPS Growth Rate	[6] Yahoo! Finance Projected EPS Growth Rate	[7] Zacks Projected EPS Growth Rate	[8] Average Projected EPS Growth Rate	[9] Cost of Equity: Minimum Growth Rate	[10] Cost of Equity: Mean Growth Rate	[11] Cost of Equity: Maximum Growth Rate
ALLETE, Inc.	ALE	$2.71	$54.18	5.00%	5.19%	6.00%	8.10%	8.10%	7.40%	11.15%	12.59%	13.30%
Alliant Energy Corporation	LNT	$1.81	$49.32	3.67%	3.79%	6.50%	6.65%	6.30%	6.48%	10.09%	10.27%	10.44%
Ameren Corporation	AEE	$2.52	$76.88	3.28%	3.38%	6.50%	6.20%	6.60%	6.43%	9.58%	9.82%	9.99%
American Electric Power Company, Inc	AEP	$3.52	$76.65	4.59%	4.71%	6.50%	3.70%	4.80%	5.00%	8.38%	9.71%	11.24%
Avista Corporation	AVA	$1.84	$33.32	5.52%	5.69%	6.00%	5.90%	5.90%	5.93%	11.59%	11.62%	11.69%
CMS Energy Corporation	CMS	$1.95	$55.46	3.52%	3.64%	6.50%	7.70%	7.50%	7.23%	10.13%	10.88%	11.35%
Duke Energy Corporation	DUK	$4.10	$88.52	4.63%	4.77%	5.00%	6.55%	6.10%	5.88%	9.75%	10.65%	11.33%
Entergy Corporation	ETR	$4.52	$96.53	4.68%	4.82%	0.50%	11.00%	6.40%	5.97%	5.19%	10.79%	15.94%
Evergy, Inc.	EVRG	$2.57	$49.33	5.21%	5.33%	7.50%	2.50%	4.30%	4.77%	7.77%	10.10%	12.90%
IDACORP, Inc.	IDA	$3.32	$96.12	3.45%	3.52%	4.00%	3.70%	4.10%	3.93%	7.22%	7.46%	7.62%
NextEra Energy, Inc.	NEE	$1.87	$56.48	3.31%	3.45%	9.50%	8.15%	8.20%	8.62%	11.60%	12.07%	12.97%
NorthWestern Corporation	NWE	$2.56	$49.46	5.18%	5.29%	3.50%	4.08%	5.20%	4.26%	8.77%	9.55%	10.51%
OGE Energy Corporation	OGE	$1.67	$34.43	4.86%	4.98%	6.50%	negative	3.70%	5.10%	8.65%	10.08%	11.52%
Pinnacle West Capital Corporation	PNW	$3.52	$72.98	4.82%	4.94%	2.50%	5.90%	5.90%	4.77%	7.38%	9.70%	10.87%
Portland General Electric Company	POR	$1.90	$40.73	4.66%	4.79%	5.00%	4.60%	6.00%	5.20%	9.37%	9.99%	10.80%
Southern Company	SO	$2.80	$68.05	4.11%	4.24%	6.50%	7.10%	4.00%	5.87%	8.20%	10.10%	11.36%
Xcel Energy Inc.	XEL	$2.08	$59.77	3.48%	3.59%	6.00%	6.80%	6.10%	6.30%	9.58%	9.89%	10.40%
Mean										9.08%	10.31%	11.43%
Median										9.37%	10.10%	11.33%

Notes:
[1] Bloomberg Professional as of November 30, 2023
[2] Bloomberg Professional 30-day average as of November 30, 2023
[3] Equals [1]/[2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Value Line
[6] Yahoo! Finance
[7] Zacks
[8] Equals average of [5], [6], [7]
[9] Equals [3] x (1 + 0.5 x (min([5], [6], [7])) + (min([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x (max([5], [6], [7])) + (max([5], [6], [7])

90-DAY CONSTANT GROWTH DCF

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company		Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Projected EPS Growth Rate	Yahoo! Finance Projected EPS Growth Rate	Zacks Projected EPS Growth Rate	Average Projected EPS Growth Rate	Cost of Equity: Minimum Growth Rate	Cost of Equity: Mean Growth Rate	Cost of Equity: Maximum Growth Rate
ALLETE, Inc.	ALE	$2.71	$54.27	4.99%	5.18%	6.00%	8.10%	8.10%	7.40%	11.14%	12.58%	13.30%
Alliant Energy Corporation	LNT	$1.81	$49.86	3.63%	3.75%	6.50%	6.65%	6.30%	6.48%	10.04%	10.23%	10.40%
Ameren Corporation	AEE	$2.52	$78.29	3.22%	3.32%	6.50%	6.20%	6.60%	6.43%	9.52%	9.76%	9.92%
American Electric Power Company, Inc	AEP	$3.52	$77.17	4.56%	4.68%	6.50%	3.70%	4.80%	5.00%	8.35%	9.68%	11.21%
Avista Corporation	AVA	$1.84	$33.50	5.49%	5.66%	6.00%	5.90%	5.90%	5.93%	11.55%	11.59%	11.66%
CMS Energy Corporation	CMS	$1.95	$55.55	3.51%	3.64%	6.50%	7.70%	7.50%	7.23%	10.12%	10.87%	11.35%
Duke Energy Corporation	DUK	$4.10	$89.10	4.60%	4.74%	5.00%	6.55%	6.10%	5.88%	9.72%	10.62%	11.30%
Entergy Corporation	ETR	$4.52	$95.22	4.75%	4.89%	0.50%	11.00%	6.40%	5.97%	5.26%	10.86%	16.01%
Evergy, Inc.	EVRG	$2.57	$52.10	4.93%	5.05%	7.50%	2.50%	4.30%	4.77%	7.49%	9.82%	12.62%
IDACORP, Inc.	IDA	$3.32	$95.86	3.46%	3.53%	4.00%	3.70%	4.10%	3.93%	7.23%	7.46%	7.63%
NextEra Energy, Inc.	NEE	$1.87	$61.29	3.05%	3.18%	9.50%	8.15%	8.20%	8.62%	11.33%	11.80%	12.70%
NorthWestern Corporation	NWE	$2.56	$50.42	5.08%	5.19%	3.50%	4.08%	5.20%	4.26%	8.67%	9.45%	10.41%
OGE Energy Corporation	OGE	$1.67	$34.14	4.90%	5.03%	6.50%	negative	3.70%	5.10%	8.69%	10.13%	11.56%
Pinnacle West Capital Corporation	PNW	$3.52	$75.15	4.68%	4.80%	2.50%	5.90%	5.90%	4.77%	7.24%	9.56%	10.72%
Portland General Electric Company	POR	$1.90	$42.56	4.46%	4.58%	5.00%	4.60%	6.00%	5.20%	9.17%	9.78%	10.60%
Southern Company	SO	$2.80	$67.52	4.15%	4.27%	6.50%	7.10%	4.00%	5.87%	8.23%	10.14%	11.39%
Xcel Energy Inc.	XEL	$2.08	$58.79	3.54%	3.65%	6.00%	6.80%	6.10%	6.30%	9.64%	9.95%	10.46%
Mean										9.02%	10.25%	11.37%
Median										9.17%	10.13%	11.30%

Notes:
[1] Bloomberg Professional as of November 30, 2023
[2] Bloomberg Professional 90-day average as of November 30, 2023
[3] Equals [1]/[2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Value Line
[6] Yahoo! Finance
[7] Zacks
[8] Equals average of [5], [6], [7]
[9] Equals [3] x (1 + 0.5 x (min([5], [6], [7])) + (min([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x (max([5], [6], [7])) + (max([5], [6], [7])

180-DAY CONSTANT GROWTH DCF

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company		Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Projected EPS Growth Rate	Yahoo! Finance Projected EPS Growth Rate	Zacks Projected EPS Growth Rate	Average Projected EPS Growth Rate	Cost of Equity: Minimum Growth Rate	Cost of Equity: Mean Growth Rate	Cost of Equity: Maximum Growth Rate
ALLETE, Inc.	ALE	$2.71	$56.88	4.76%	4.94%	6.00%	8.10%	8.10%	7.40%	10.91%	12.34%	13.06%
Alliant Energy Corporation	LNT	$1.81	$51.12	3.54%	3.66%	6.50%	6.65%	6.30%	6.48%	9.95%	10.14%	10.31%
Ameren Corporation	AEE	$2.52	$81.27	3.10%	3.20%	6.50%	6.20%	6.60%	6.43%	9.40%	9.63%	9.80%
American Electric Power Company, Inc	AEP	$3.52	$81.52	4.32%	4.43%	6.50%	3.70%	4.80%	5.00%	8.10%	9.43%	10.96%
Avista Corporation	AVA	$1.84	$36.89	4.99%	5.14%	6.00%	5.90%	5.90%	5.93%	11.04%	11.07%	11.14%
CMS Energy Corporation	CMS	$1.95	$57.38	3.40%	3.52%	6.50%	7.70%	7.50%	7.23%	10.01%	10.75%	11.23%
Duke Energy Corporation	DUK	$4.10	$90.33	4.54%	4.67%	5.00%	6.55%	6.10%	5.88%	9.65%	10.56%	11.24%
Entergy Corporation	ETR	$4.52	$97.81	4.62%	4.76%	0.50%	11.00%	6.40%	5.97%	5.13%	10.73%	15.88%
Evergy, Inc.	EVRG	$2.57	$55.28	4.65%	4.76%	7.50%	2.50%	4.30%	4.77%	7.21%	9.53%	12.32%
IDACORP, Inc.	IDA	$3.32	$100.25	3.31%	3.38%	4.00%	3.70%	4.10%	3.93%	7.07%	7.31%	7.48%
NextEra Energy, Inc.	NEE	$1.87	$67.60	2.77%	2.89%	9.50%	8.15%	8.20%	8.62%	11.03%	11.50%	12.40%
NorthWestern Corporation	NWE	$2.56	$53.59	4.78%	4.88%	3.50%	4.08%	5.20%	4.26%	8.36%	9.14%	10.10%
OGE Energy Corporation	OGE	$1.67	$34.93	4.79%	4.91%	6.50%	negative	3.70%	5.10%	8.58%	10.01%	11.44%
Pinnacle West Capital Corporation	PNW	$3.52	$76.59	4.60%	4.71%	2.50%	5.90%	5.90%	4.77%	7.15%	9.47%	10.63%
Portland General Electric Company	POR	$1.90	$45.25	4.20%	4.31%	5.00%	4.60%	6.00%	5.20%	8.90%	9.51%	10.32%
Southern Company	SO	$2.80	$68.47	4.09%	4.21%	6.50%	7.10%	4.00%	5.87%	8.17%	10.08%	11.33%
Xcel Energy Inc.	XEL	$2.08	$61.98	3.36%	3.46%	6.00%	6.80%	6.10%	6.30%	9.46%	9.76%	10.27%
Mean										8.83%	10.06%	11.17%
Median										8.90%	10.01%	11.14%

Notes:
[1] Bloomberg Professional as of November 30, 2023
[2] Bloomberg Professional 180-day average as of November 30, 2023
[3] Equals [1]/[2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Value Line
[6] Yahoo! Finance
[7] Zacks
[8] Equals average of [5], [6], [7]
[9] Equals [3] x (1 + 0.5 x (min([5], [6], [7])) + (min([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x (max([5], [6], [7])) + (max([5], [6], [7])

Docket No. UE 433
Exhibit PAC/405
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

February 2024

MULTI-STAGE DCF

AVERAGE FIRST STAGE GROWTH RATE
STOCK PRICE AVERAGING CONVENTION: 30 DAYS

Company		1 Annualized Dividend	2 Stock Price	3 First Stage Gwth Rate	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	$2.71	$54.18	6.00%	5.92%	5.84%	5.75%	5.67%	5.59%	5.51%	11.07%
Alliant Energy Corporation	LNT	$1.81	$49.32	6.30%	6.17%	6.04%	5.90%	5.77%	5.64%	5.51%	9.63%
Ameren Corporation	AEE	$2.52	$76.88	6.20%	6.08%	5.97%	5.85%	5.74%	5.62%	5.51%	9.16%
American Electric Power Company, Inc.	AEP	$3.52	$76.65	3.70%	4.00%	4.30%	4.60%	4.90%	5.21%	5.51%	9.96%
Avista Corporation	AVA	$1.84	$33.32	5.90%	5.83%	5.77%	5.70%	5.64%	5.57%	5.51%	11.62%
CMS Energy Corporation	CMS	$1.95	$55.46	6.50%	6.33%	6.17%	6.00%	5.84%	5.67%	5.51%	9.50%
Duke Energy Corporation	DUK	$4.10	$88.52	5.00%	5.08%	5.17%	5.25%	5.34%	5.42%	5.51%	10.36%
Entergy Corporation	ETR	$4.52	$96.53	0.50%	1.33%	2.17%	3.00%	3.84%	4.67%	5.51%	9.24%
Evergy, Inc.	EVRG	$2.57	$49.33	2.50%	3.00%	3.50%	4.00%	4.50%	5.01%	5.51%	10.23%
IDACORP, Inc.	IDA	$3.32	$96.12	3.70%	4.00%	4.30%	4.60%	4.90%	5.21%	5.51%	8.82%
NextEra Energy, Inc.	NEE	$1.87	$56.48	8.15%	7.71%	7.27%	6.83%	6.39%	5.95%	5.51%	9.65%
NorthWestern Corporation	NWE	$2.56	$49.46	3.50%	3.83%	4.17%	4.50%	4.84%	5.17%	5.51%	10.49%
OGE Energy Corporation	OGE	$1.67	$34.43	3.70%	4.00%	4.30%	4.60%	4.90%	5.21%	5.51%	10.23%
Pinnacle West Capital Corporation	PNW	$3.52	$72.98	2.50%	3.00%	3.50%	4.00%	4.50%	5.01%	5.51%	9.87%
Portland General Electric Company	POR	$1.90	$40.73	4.60%	4.75%	4.90%	5.05%	5.20%	5.36%	5.51%	10.28%
Southern Company	SO	$2.80	$68.05	4.00%	4.25%	4.50%	4.75%	5.00%	5.26%	5.51%	9.55%
Xcel Energy Inc.	XEL	$2.08	$59.77	6.00%	5.92%	5.84%	5.75%	5.67%	5.59%	5.51%	9.35%
Mean					4.78%	4.92%	5.07%	5.22%	5.36%	5.51%	9.94%
Median					4.75%	4.90%	5.05%	5.20%	5.36%	5.51%	9.87%

Notes:
[1] Bloomberg Professional as of November 30, 2023
[2] Bloomberg Professional 30-day average as of November 30, 2023
[3] Attachment PAC 404
[4] Equals [3] + ([9] − [3]) / 6
[5] Equals [4] + ([9] − [3]) / 6
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[7] Equals [6] + ([9] − [3]) / 6
[8] Equals [7] + ([9] − [3]) / 6
[9] Attachment PAC 406
[10] Equals internal rate of return of cash flows for Year 0 through Year 20(

MULTI-STAGE DCF

AVERAGE FIRST STAGE 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 Gwth Rate	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth Rate	ROE
ALLETE, Inc.	ALE	$2.71	$54.27	6.00%	5.92%	5.84%	5.75%	5.67%	5.59%	5.51%	11.06%
Alliant Energy Corporation	LNT	$1.81	$49.86	6.30%	6.17%	6.04%	5.90%	5.77%	5.64%	5.51%	9.59%
Ameren Corporation	AEE	$2.52	$78.29	6.20%	6.08%	5.97%	5.85%	5.74%	5.62%	5.51%	9.09%
American Electric Power Company, Inc.	AEP	$3.52	$77.17	3.70%	4.00%	4.30%	4.60%	4.90%	5.21%	5.51%	9.93%
Avista Corporation	AVA	$1.84	$33.50	5.90%	5.83%	5.77%	5.70%	5.64%	5.57%	5.51%	11.59%
CMS Energy Corporation	CMS	$1.95	$55.55	6.50%	6.33%	6.17%	6.00%	5.84%	5.67%	5.51%	9.50%
Duke Energy Corporation	DUK	$4.10	$89.10	5.00%	5.08%	5.17%	5.25%	5.34%	5.42%	5.51%	10.32%
Entergy Corporation	ETR	$4.52	$95.22	0.50%	1.33%	2.17%	3.00%	3.84%	4.67%	5.51%	9.29%
Evergy, Inc.	EVRG	$2.57	$52.10	2.50%	3.00%	3.50%	4.00%	4.50%	5.01%	5.51%	9.97%
IDACORP, Inc.	IDA	$3.32	$95.86	3.70%	4.00%	4.30%	4.60%	4.90%	5.21%	5.51%	8.83%
NextEra Energy, Inc.	NEE	$1.87	$61.29	8.15%	7.71%	7.27%	6.83%	6.39%	5.95%	5.51%	9.32%
NorthWestern Corporation	NWE	$2.56	$50.42	3.50%	3.83%	4.17%	4.50%	4.84%	5.17%	5.51%	10.39%
OGE Energy Corporation	OGE	$1.67	$34.14	3.70%	4.00%	4.30%	4.60%	4.90%	5.21%	5.51%	10.27%
Pinnacle West Capital Corporation	PNW	$3.52	$75.15	2.50%	3.00%	3.50%	4.00%	4.50%	5.01%	5.51%	9.73%
Portland General Electric Company	POR	$1.90	$42.56	4.60%	4.75%	4.90%	5.05%	5.20%	5.36%	5.51%	10.07%
Southern Company	SO	$2.80	$67.52	4.00%	4.25%	4.50%	4.75%	5.00%	5.26%	5.51%	9.58%
Xcel Energy Inc.	XEL	$2.08	$58.79	6.00%	5.92%	5.84%	5.75%	5.67%	5.59%	5.51%	9.41%
Mean					4.78%	4.92%	5.07%	5.22%	5.36%	5.51%	9.88%
Median					4.75%	4.90%	5.05%	5.20%	5.36%	5.51%	9.73%

Notes:
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[7] Equals [6] + ([9] − [3]) / 6
[8] Equals [7] + ([9] − [3]) / 6
[9] Attachment PAC 406
[10] Equals internal rate of return of cash flows for Year 0 through Year 20(

MULTI-STAGE DCF

AVERAGE FIRST STAGE GROWTH RATE
STOCK PRICE AVERAGING CONVENTION: 180 DAYS

Company		1 Annualized Dividend	2 Stock Price	3 First Stage Gwth Rate	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	$2.71	$56.88	6.00%	5.92%	5.84%	5.75%	5.67%	5.59%	5.51%	10.80%
Alliant Energy Corporation	LNT	$1.81	$51.12	6.30%	6.17%	6.04%	5.90%	5.77%	5.64%	5.51%	9.48%
Ameren Corporation	AEE	$2.52	$81.27	6.20%	6.08%	5.97%	5.85%	5.74%	5.62%	5.51%	8.96%
American Electric Power Company, Inc.	AEP	$3.52	$81.52	3.70%	4.00%	4.30%	4.60%	4.90%	5.21%	5.51%	9.68%
Avista Corporation	AVA	$1.84	$36.89	5.90%	5.83%	5.77%	5.70%	5.64%	5.57%	5.51%	11.02%
CMS Energy Corporation	CMS	$1.95	$57.38	6.50%	6.33%	6.17%	6.00%	5.84%	5.67%	5.51%	9.37%
Duke Energy Corporation	DUK	$4.10	$90.33	5.00%	5.08%	5.17%	5.25%	5.34%	5.42%	5.51%	10.26%
Entergy Corporation	ETR	$4.52	$97.81	0.50%	1.33%	2.17%	3.00%	3.84%	4.67%	5.51%	9.19%
Evergy, Inc.	EVRG	$2.57	$55.28	2.50%	3.00%	3.50%	4.00%	4.50%	5.01%	5.51%	9.70%
IDACORP, Inc.	IDA	$3.32	$100.25	3.70%	4.00%	4.30%	4.60%	4.90%	5.21%	5.51%	8.68%
NextEra Energy, Inc.	NEE	$1.87	$67.60	8.15%	7.71%	7.27%	6.83%	6.39%	5.95%	5.51%	8.96%
NorthWestern Corporation	NWE	$2.56	$53.59	3.50%	3.83%	4.17%	4.50%	4.84%	5.17%	5.51%	10.09%
OGE Energy Corporation	OGE	$1.67	$34.93	3.70%	4.00%	4.30%	4.60%	4.90%	5.21%	5.51%	10.16%
Pinnacle West Capital Corporation	PNW	$3.52	$76.59	2.50%	3.00%	3.50%	4.00%	4.50%	5.01%	5.51%	9.65%
Portland General Electric Company	POR	$1.90	$45.25	4.60%	4.75%	4.90%	5.05%	5.20%	5.36%	5.51%	9.79%
Southern Company	SO	$2.80	$68.47	4.00%	4.25%	4.50%	4.75%	5.00%	5.26%	5.51%	9.53%
Xcel Energy Inc.	XEL	$2.08	$61.98	6.00%	5.92%	5.84%	5.75%	5.67%	5.59%	5.51%	9.21%
Mean					4.78%	4.92%	5.07%	5.22%	5.36%	5.51%	9.68%
Median					4.75%	4.90%	5.05%	5.20%	5.36%	5.51%	9.65%

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MULTI-STAGE DCF

AVERAGE FIRST STAGE GROWTH RATE
STOCK PRICE AVERAGING CONVENTION: 30 DAYS

Company		1 Annualized Dividend	2 Stock Price	3 First Stage Gwth Rate	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	$2.71	$54.18	7.40%	7.08%	6.77%	6.45%	6.14%	5.82%	5.51%	11.52%
Alliant Energy Corporation	LNT	$1.81	$49.32	6.48%	6.32%	6.16%	6.00%	5.83%	5.67%	5.51%	9.68%
Ameren Corporation	AEE	$2.52	$76.88	6.43%	6.28%	6.12%	5.97%	5.82%	5.66%	5.51%	9.21%
American Electric Power Company, Inc.	AEP	$3.52	$76.65	5.00%	5.08%	5.17%	5.25%	5.34%	5.42%	5.51%	10.31%
Avista Corporation	AVA	$1.84	$33.32	5.93%	5.86%	5.79%	5.72%	5.65%	5.58%	5.51%	11.64%
CMS Energy Corporation	CMS	$1.95	$55.46	7.23%	6.95%	6.66%	6.37%	6.08%	5.79%	5.51%	9.68%
Duke Energy Corporation	DUK	$4.10	$88.52	5.88%	5.82%	5.76%	5.70%	5.63%	5.57%	5.51%	10.61%
Entergy Corporation	ETR	$4.52	$96.53	5.97%	5.89%	5.81%	5.74%	5.66%	5.58%	5.51%	10.69%
Evergy, Inc.	EVRG	$2.57	$49.33	4.77%	4.89%	5.01%	5.14%	5.26%	5.38%	5.51%	10.91%
IDACORP, Inc.	IDA	$3.32	$96.12	3.93%	4.20%	4.46%	4.72%	4.98%	5.24%	5.51%	8.87%
NextEra Energy, Inc.	NEE	$1.87	$56.48	8.62%	8.10%	7.58%	7.06%	6.54%	6.03%	5.51%	9.76%
NorthWestern Corporation	NWE	$2.56	$49.46	4.26%	4.47%	4.68%	4.88%	5.09%	5.30%	5.51%	10.72%
OGE Energy Corporation	OGE	$1.67	$34.43	5.10%	5.17%	5.24%	5.30%	5.37%	5.44%	5.51%	10.63%
Pinnacle West Capital Corporation	PNW	$3.52	$72.98	4.77%	4.89%	5.01%	5.14%	5.26%	5.38%	5.51%	10.50%
Portland General Electric Company	POR	$1.90	$40.73	5.20%	5.25%	5.30%	5.35%	5.40%	5.46%	5.51%	10.45%
Southern Company	SO	$2.80	$68.05	5.87%	5.81%	5.75%	5.69%	5.63%	5.57%	5.51%	10.03%
Xcel Energy Inc.	XEL	$2.08	$59.77	6.30%	6.17%	6.04%	5.90%	5.77%	5.64%	5.51%	9.41%
Mean					5.78%	5.72%	5.67%	5.62%	5.56%	5.51%	10.27%
Median					5.82%	5.76%	5.70%	5.63%	5.57%	5.51%	10.45%

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MULTI-STAGE DCF

AVERAGE FIRST STAGE GROWTH RATE
STOCK PRICE AVERAGING CONVENTION: 90 DAYS

Company		1 Annualized Dividend	2 Stock Price	3 First Stage Gwth Rate	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	$2.71	$54.27	7.40%	7.08%	6.77%	6.45%	6.14%	5.82%	5.51%	11.51%
Alliant Energy Corporation	LNT	$1.81	$49.86	6.48%	6.32%	6.16%	6.00%	5.83%	5.67%	5.51%	9.63%
Ameren Corporation	AEE	$2.52	$78.29	6.43%	6.28%	6.12%	5.97%	5.82%	5.66%	5.51%	9.14%
American Electric Power Company, Inc.	AEP	$3.52	$77.17	5.00%	5.08%	5.17%	5.25%	5.34%	5.42%	5.51%	10.28%
Avista Corporation	AVA	$1.84	$33.50	5.93%	5.86%	5.79%	5.72%	5.65%	5.58%	5.51%	11.60%
CMS Energy Corporation	CMS	$1.95	$55.55	7.23%	6.95%	6.66%	6.37%	6.08%	5.79%	5.51%	9.67%
Duke Energy Corporation	DUK	$4.10	$89.10	5.88%	5.82%	5.76%	5.70%	5.63%	5.57%	5.51%	10.58%
Entergy Corporation	ETR	$4.52	$95.22	5.97%	5.89%	5.81%	5.74%	5.66%	5.58%	5.51%	10.77%
Evergy, Inc.	EVRG	$2.57	$52.10	4.77%	4.89%	5.01%	5.14%	5.26%	5.38%	5.51%	10.61%
IDACORP, Inc.	IDA	$3.32	$95.86	3.93%	4.20%	4.46%	4.72%	4.98%	5.24%	5.51%	8.88%
NextEra Energy, Inc.	NEE	$1.87	$61.29	8.62%	8.10%	7.58%	7.06%	6.54%	6.03%	5.51%	9.43%
NorthWestern Corporation	NWE	$2.56	$50.42	4.26%	4.47%	4.68%	4.88%	5.09%	5.30%	5.51%	10.61%
OGE Energy Corporation	OGE	$1.67	$34.14	5.10%	5.17%	5.24%	5.30%	5.37%	5.44%	5.51%	10.68%
Pinnacle West Capital Corporation	PNW	$3.52	$75.15	4.77%	4.89%	5.01%	5.14%	5.26%	5.38%	5.51%	10.35%
Portland General Electric Company	POR	$1.90	$42.56	5.20%	5.25%	5.30%	5.35%	5.40%	5.46%	5.51%	10.23%
Southern Company	SO	$2.80	$67.52	5.87%	5.81%	5.75%	5.69%	5.63%	5.57%	5.51%	10.06%
Xcel Energy Inc.	XEL	$2.08	$58.79	6.30%	6.17%	6.04%	5.90%	5.77%	5.64%	5.51%	9.48%
Mean					5.78%	5.72%	5.67%	5.62%	5.56%	5.51%	10.21%
Median					5.82%	5.76%	5.70%	5.63%	5.57%	5.51%	10.28%

Notes:
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MULTI-STAGE DCF

AVERAGE FIRST STAGE 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 Gwth Rate	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth Rate	ROE
ALLETE, Inc.	ALE	$2.71	$56.88	7.40%	7.08%	6.77%	6.45%	6.14%	5.82%	5.51%	11.23%
Alliant Energy Corporation	LNT	$1.81	$51.12	6.48%	6.32%	6.16%	6.00%	5.83%	5.67%	5.51%	9.53%
Ameren Corporation	AEE	$2.52	$81.27	6.43%	6.28%	6.12%	5.97%	5.82%	5.66%	5.51%	9.01%
American Electric Power Company, Inc.	AEP	$3.52	$81.52	5.00%	5.08%	5.17%	5.25%	5.34%	5.42%	5.51%	10.02%
Avista Corporation	AVA	$1.84	$36.89	5.93%	5.86%	5.79%	5.72%	5.65%	5.58%	5.51%	11.03%
CMS Energy Corporation	CMS	$1.95	$57.38	7.23%	6.95%	6.66%	6.37%	6.08%	5.79%	5.51%	9.54%
Duke Energy Corporation	DUK	$4.10	$90.33	5.88%	5.82%	5.76%	5.70%	5.63%	5.57%	5.51%	10.51%
Entergy Corporation	ETR	$4.52	$97.81	5.97%	5.89%	5.81%	5.74%	5.66%	5.58%	5.51%	10.62%
Evergy, Inc.	EVRG	$2.57	$55.28	4.77%	4.89%	5.01%	5.14%	5.26%	5.38%	5.51%	10.31%
IDACORP, Inc.	IDA	$3.32	$100.25	3.93%	4.20%	4.46%	4.72%	4.98%	5.24%	5.51%	8.72%
NextEra Energy, Inc.	NEE	$1.87	$67.60	8.62%	8.10%	7.58%	7.06%	6.54%	6.03%	5.51%	9.06%
NorthWestern Corporation	NWE	$2.56	$53.59	4.26%	4.47%	4.68%	4.88%	5.09%	5.30%	5.51%	10.30%
OGE Energy Corporation	OGE	$1.67	$34.93	5.10%	5.17%	5.24%	5.30%	5.37%	5.44%	5.51%	10.56%
Pinnacle West Capital Corporation	PNW	$3.52	$76.59	4.77%	4.89%	5.01%	5.14%	5.26%	5.38%	5.51%	10.25%
Portland General Electric Company	POR	$1.90	$45.25	5.20%	5.25%	5.30%	5.35%	5.40%	5.46%	5.51%	9.94%
Southern Company	SO	$2.80	$68.47	5.87%	5.81%	5.75%	5.69%	5.63%	5.57%	5.51%	10.00%
Xcel Energy Inc.	XEL	$2.08	$61.98	6.30%	6.17%	6.04%	5.90%	5.77%	5.64%	5.51%	9.27%
Mean					5.78%	5.72%	5.67%	5.62%	5.56%	5.51%	9.99%
Median					5.82%	5.76%	5.70%	5.63%	5.57%	5.51%	10.02%

Notes:
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[6] Equals [5] + ([9] − [3]) / 6
[7] Equals [6] + ([9] − [3]) / 6
[8] Equals [7] + ([9] − [3]) / 6
[9] Attachment PAC 406
[10] Equals internal rate of return of cash flows for Year 0 through Year 20(

MULTI-STAGE DCF

AVERAGE FIRST STAGE 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 Gwth Rate	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth Rate	ROE
ALLETE, Inc.	ALE	$2.71	$54.18	8.10%	7.67%	7.24%	6.80%	6.37%	5.94%	5.51%	11.75%
Alliant Energy Corporation	LNT	$1.81	$49.32	6.65%	6.46%	6.27%	6.08%	5.89%	5.70%	5.51%	9.72%
Ameren Corporation	AEE	$2.52	$76.88	6.60%	6.42%	6.24%	6.05%	5.87%	5.69%	5.51%	9.25%
American Electric Power Company, Inc.	AEP	$3.52	$76.65	6.50%	6.33%	6.17%	6.00%	5.84%	5.67%	5.51%	10.75%
Avista Corporation	AVA	$1.84	$33.32	6.00%	5.92%	5.84%	5.75%	5.67%	5.59%	5.51%	11.66%
CMS Energy Corporation	CMS	$1.95	$55.46	7.70%	7.33%	6.97%	6.60%	6.24%	5.87%	5.51%	9.79%
Duke Energy Corporation	DUK	$4.10	$88.52	6.55%	6.38%	6.20%	6.03%	5.85%	5.68%	5.51%	10.81%
Entergy Corporation	ETR	$4.52	$96.53	11.00%	10.08%	9.17%	8.25%	7.34%	6.42%	5.51%	12.33%
Evergy, Inc.	EVRG	$2.57	$49.33	7.50%	7.17%	6.84%	6.50%	6.17%	5.84%	5.51%	11.80%
IDACORP, Inc.	IDA	$3.32	$96.12	4.10%	4.33%	4.57%	4.80%	5.04%	5.27%	5.51%	8.90%
NextEra Energy, Inc.	NEE	$1.87	$56.48	9.50%	8.83%	8.17%	7.50%	6.84%	6.17%	5.51%	9.98%
NorthWestern Corporation	NWE	$2.56	$49.46	5.20%	5.25%	5.30%	5.35%	5.40%	5.46%	5.51%	11.01%
OGE Energy Corporation	OGE	$1.67	$34.43	6.50%	6.33%	6.17%	6.00%	5.84%	5.67%	5.51%	11.06%
Pinnacle West Capital Corporation	PNW	$3.52	$72.98	5.90%	5.83%	5.77%	5.70%	5.64%	5.57%	5.51%	10.83%
Portland General Electric Company	POR	$1.90	$40.73	6.00%	5.92%	5.84%	5.75%	5.67%	5.59%	5.51%	10.68%
Southern Company	SO	$2.80	$68.05	7.10%	6.83%	6.57%	6.30%	6.04%	5.77%	5.51%	10.36%
Xcel Energy Inc.	XEL	$2.08	$59.77	6.80%	6.58%	6.37%	6.15%	5.94%	5.72%	5.51%	9.53%
Mean					6.69%	6.45%	6.22%	5.98%	5.74%	5.51%	10.60%
Median					6.42%	6.24%	6.05%	5.87%	5.69%	5.51%	10.75%

Notes:
[1] Bloomberg Professional as of November 30, 2023
[2] Bloomberg Professional 30-day average as of November 30, 2023
[3] Attachment PAC 404
[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] Attachment PAC 406
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

MULTI-STAGE DCF

AVERAGE FIRST STAGE 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 Gwth Rate	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth Rate	ROE
ALLETE, Inc.	ALE	$2.71	$54.27	8.10%	7.67%	7.24%	6.80%	6.37%	5.94%	5.51%	11.74%
Alliant Energy Corporation	LNT	$1.81	$49.86	6.65%	6.46%	6.27%	6.08%	5.89%	5.70%	5.51%	9.67%
Ameren Corporation	AEE	$2.52	$78.29	6.60%	6.42%	6.24%	6.05%	5.87%	5.69%	5.51%	9.18%
American Electric Power Company, Inc.	AEP	$3.52	$77.17	6.50%	6.33%	6.17%	6.00%	5.84%	5.67%	5.51%	10.71%
Avista Corporation	AVA	$1.84	$33.50	6.00%	5.92%	5.84%	5.75%	5.67%	5.59%	5.51%	11.62%
CMS Energy Corporation	CMS	$1.95	$55.55	7.70%	7.33%	6.97%	6.60%	6.24%	5.87%	5.51%	9.79%
Duke Energy Corporation	DUK	$4.10	$89.10	6.55%	6.38%	6.20%	6.03%	5.85%	5.68%	5.51%	10.77%
Entergy Corporation	ETR	$4.52	$95.22	11.00%	10.08%	9.17%	8.25%	7.34%	6.42%	5.51%	12.42%
Evergy, Inc.	EVRG	$2.57	$52.10	7.50%	7.17%	6.84%	6.50%	6.17%	5.84%	5.51%	11.47%
IDACORP, Inc.	IDA	$3.32	$95.86	4.10%	4.33%	4.57%	4.80%	5.04%	5.27%	5.51%	8.91%
NextEra Energy, Inc.	NEE	$1.87	$61.29	9.50%	8.83%	8.17%	7.50%	6.84%	6.17%	5.51%	9.63%
NorthWestern Corporation	NWE	$2.56	$50.42	5.20%	5.25%	5.30%	5.35%	5.40%	5.46%	5.51%	10.90%
OGE Energy Corporation	OGE	$1.67	$34.14	6.50%	6.33%	6.17%	6.00%	5.84%	5.67%	5.51%	11.11%
Pinnacle West Capital Corporation	PNW	$3.52	$75.15	5.90%	5.83%	5.77%	5.70%	5.64%	5.57%	5.51%	10.68%
Portland General Electric Company	POR	$1.90	$42.56	6.00%	5.92%	5.84%	5.75%	5.67%	5.59%	5.51%	10.46%
Southern Company	SO	$2.80	$67.52	7.10%	6.83%	6.57%	6.30%	6.04%	5.77%	5.51%	10.40%
Xcel Energy Inc.	XEL	$2.08	$58.79	6.80%	6.58%	6.37%	6.15%	5.94%	5.72%	5.51%	9.60%
Mean					6.69%	6.45%	6.22%	5.98%	5.74%	5.51%	10.53%
Median					6.42%	6.24%	6.05%	5.87%	5.69%	5.51%	10.68%

Notes:
[1] Bloomberg Professional as of November 30, 2023
[2] Bloomberg Professional 90-day average as of November 30, 2023
[3] Attachment PAC 404
[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] Attachment PAC 406
[10] Equals internal rate of return of cash flows for Year 0 through Year 20(

MULTI-STAGE DCF

AVERAGE FIRST STAGE 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 Gwth Rate	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth Rate	ROE
ALLETE, Inc.	ALE	$2.71	$56.88	8.10%	7.67%	7.24%	6.80%	6.37%	5.94%	5.51%	11.45%
Alliant Energy Corporation	LNT	$1.81	$51.12	6.65%	6.46%	6.27%	6.08%	5.89%	5.70%	5.51%	9.57%
Ameren Corporation	AEE	$2.52	$81.27	6.60%	6.42%	6.24%	6.05%	5.87%	5.69%	5.51%	9.04%
American Electric Power Company, Inc.	AEP	$3.52	$81.52	6.50%	6.33%	6.17%	6.00%	5.84%	5.67%	5.51%	10.43%
Avista Corporation	AVA	$1.84	$36.89	6.00%	5.92%	5.84%	5.75%	5.67%	5.59%	5.51%	11.05%
CMS Energy Corporation	CMS	$1.95	$57.38	7.70%	7.33%	6.97%	6.60%	6.24%	5.87%	5.51%	9.65%
Duke Energy Corporation	DUK	$4.10	$90.33	6.55%	6.38%	6.20%	6.03%	5.85%	5.68%	5.51%	10.70%
Entergy Corporation	ETR	$4.52	$97.81	11.00%	10.08%	9.17%	8.25%	7.34%	6.42%	5.51%	12.24%
Evergy, Inc.	EVRG	$2.57	$55.28	7.50%	7.17%	6.84%	6.50%	6.17%	5.84%	5.51%	11.12%
IDACORP, Inc.	IDA	$3.32	$100.25	4.10%	4.33%	4.57%	4.80%	5.04%	5.27%	5.51%	8.76%
NextEra Energy, Inc.	NEE	$1.87	$67.60	9.50%	8.83%	8.17%	7.50%	6.84%	6.17%	5.51%	9.25%
NorthWestern Corporation	NWE	$2.56	$53.59	5.20%	5.25%	5.30%	5.35%	5.40%	5.46%	5.51%	10.57%
OGE Energy Corporation	OGE	$1.67	$34.93	6.50%	6.33%	6.17%	6.00%	5.84%	5.67%	5.51%	10.98%
Pinnacle West Capital Corporation	PNW	$3.52	$76.59	5.90%	5.83%	5.77%	5.70%	5.64%	5.57%	5.51%	10.58%
Portland General Electric Company	POR	$1.90	$45.25	6.00%	5.92%	5.84%	5.75%	5.67%	5.59%	5.51%	10.16%
Southern Company	SO	$2.80	$68.47	7.10%	6.83%	6.57%	6.30%	6.04%	5.77%	5.51%	10.33%
Xcel Energy Inc.	XEL	$2.08	$61.98	6.80%	6.58%	6.37%	6.15%	5.94%	5.72%	5.51%	9.39%
Mean					6.69%	6.45%	6.22%	5.98%	5.74%	5.51%	10.31%
Median					6.42%	6.24%	6.05%	5.87%	5.69%	5.51%	10.43%

Notes:
[1] Bloomberg Professional as of November 30, 2023
[2] Bloomberg Professional 180-day average as of November 30, 2023
[3] Attachment PAC 404
[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] Attachment PAC 406
[10] Equals internal rate of return of cash flows for Year 0 through Year 20(

Docket No. UE 433
Exhibit PAC/406
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Ann E. Bulkley

Gross Domestic Product Growth

February 2024

CALCULATION OF LONG-TERM GROWTH RATE FOR MULTI-STAGE DCF

Historical GDP Growth		
Real GDP ($ Billions) [1]	1929	$ 1,191.1
	2022	$ 21,822.0
Compound Annual Growth Rate		**3.18%**
Inflation Forecast		
Consumer Price Index (YoY % Change) [2]	2030-2034	2.20%
Consumer Price Index (All-Urban) [3]	2033	3.78
	2050	5.54
Compound Annual Growth Rate		2.27%
GDP Chain-type Price Index (2012=1.000) [3]	2033	1.65
	2050	2.43
Compound Annual Growth Rate		2.31%
Average Inflation Forecast		**2.26%**
Long-Term GDP Growth Rate		**5.51%**

Notes:
[1] Bureau of Economic Analysis, November 30, 2023
[2] *Blue Chip Financial Forecasts* , Vol. 42, No. 6, June 1, 2023, at 14
[3] Energy Information Administration, Annual Energy Outlook 2023, at Table 20, March 16, 2023

Docket No. UE 433
Exhibit PAC/407
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Ann E. Bulkley

Capital Asset Pricing Model and Empirical Capital Asset Pricing Model

February 2024

CAPITAL ASSET PRICING MODEL
CURRENT RISK FREE RATE AND VALUE LINE 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)	CAPM ROE (K)	ECAPM ROE (K)
ALLETE, Inc.	ALE	4.77%	0.90	12.56%	7.78%	11.78%	11.97%
Alliant Energy Corporation	LNT	4.77%	0.85	12.56%	7.78%	11.39%	11.68%
Ameren Corporation	AEE	4.77%	0.85	12.56%	7.78%	11.39%	11.68%
American Electric Power Company, Inc.	AEP	4.77%	0.80	12.56%	7.78%	11.00%	11.39%
Avista Corporation	AVA	4.77%	0.90	12.56%	7.78%	11.78%	11.97%
CMS Energy Corporation	CMS	4.77%	0.80	12.56%	7.78%	11.00%	11.39%
Duke Energy Corporation	DUK	4.77%	0.85	12.56%	7.78%	11.39%	11.68%
Entergy Corporation	ETR	4.77%	0.95	12.56%	7.78%	12.17%	12.26%
Evergy, Inc.	EVRG	4.77%	0.90	12.56%	7.78%	11.78%	11.97%
IDACORP, Inc.	IDA	4.77%	0.85	12.56%	7.78%	11.39%	11.68%
NextEra Energy, Inc.	NEE	4.77%	0.95	12.56%	7.78%	12.17%	12.26%
NorthWestern Corporation	NWE	4.77%	0.95	12.56%	7.78%	12.17%	12.26%
OGE Energy Corporation	OGE	4.77%	1.05	12.56%	7.78%	12.95%	12.85%
Pinnacle West Capital Corporation	PNW	4.77%	0.95	12.56%	7.78%	12.17%	12.26%
Portland General Electric Company	POR	4.77%	0.90	12.56%	7.78%	11.78%	11.97%
Southern Company	SO	4.77%	0.90	12.56%	7.78%	11.78%	11.97%
Xcel Energy Inc.	XEL	4.77%	0.85	12.56%	7.78%	11.39%	11.68%
Mean						11.73%	11.94%
Median						11.78%	11.97%

Notes:
[1] Bloomberg Professional 30-day average as of November 30, 2023
[2] Value Line
[3] Market Return
[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 AND VALUE LINE 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	Near-term projected 30-year U.S. Treasury bond yield (Q1 2024 - Q1 2025)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM ROE (K)	ECAPM ROE (K)
ALLETE, Inc.	ALE	4.48%	0.90	12.56%	8.08%	11.75%	11.95%
Alliant Energy Corporation	LNT	4.48%	0.85	12.56%	8.08%	11.34%	11.65%
Ameren Corporation	AEE	4.48%	0.85	12.56%	8.08%	11.34%	11.65%
American Electric Power Company, Inc.	AEP	4.48%	0.80	12.56%	8.08%	10.94%	11.34%
Avista Corporation	AVA	4.48%	0.90	12.56%	8.08%	11.75%	11.95%
CMS Energy Corporation	CMS	4.48%	0.80	12.56%	8.08%	10.94%	11.34%
Duke Energy Corporation	DUK	4.48%	0.85	12.56%	8.08%	11.34%	11.65%
Entergy Corporation	ETR	4.48%	0.95	12.56%	8.08%	12.15%	12.25%
Evergy, Inc.	EVRG	4.48%	0.90	12.56%	8.08%	11.75%	11.95%
IDACORP, Inc.	IDA	4.48%	0.85	12.56%	8.08%	11.34%	11.65%
NextEra Energy, Inc.	NEE	4.48%	0.95	12.56%	8.08%	12.15%	12.25%
NorthWestern Corporation	NWE	4.48%	0.95	12.56%	8.08%	12.15%	12.25%
OGE Energy Corporation	OGE	4.48%	1.05	12.56%	8.08%	12.96%	12.86%
Pinnacle West Capital Corporation	PNW	4.48%	0.95	12.56%	8.08%	12.15%	12.25%
Portland General Electric Company	POR	4.48%	0.90	12.56%	8.08%	11.75%	11.95%
Southern Company	SO	4.48%	0.90	12.56%	8.08%	11.75%	11.95%
Xcel Energy Inc.	XEL	4.48%	0.85	12.56%	8.08%	11.34%	11.65%
Mean						11.70%	11.91%
Median						11.75%	11.95%

Notes:
[1] Blue Chip Financial Forecasts, Vol. 42, No. 12, December 1, 2023, at 2
[2] Value Line
[3] Market Return
[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 AND VALUE LINE 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 (2025 - 2029)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM ROE (K)	ECAPM ROE (K)
ALLETE, Inc.	ALE	4.10%	0.90	12.56%	8.46%	11.71%	11.92%
Alliant Energy Corporation	LNT	4.10%	0.85	12.56%	8.46%	11.29%	11.60%
Ameren Corporation	AEE	4.10%	0.85	12.56%	8.46%	11.29%	11.60%
American Electric Power Company, Inc.	AEP	4.10%	0.80	12.56%	8.46%	10.86%	11.29%
Avista Corporation	AVA	4.10%	0.90	12.56%	8.46%	11.71%	11.92%
CMS Energy Corporation	CMS	4.10%	0.80	12.56%	8.46%	10.86%	11.29%
Duke Energy Corporation	DUK	4.10%	0.85	12.56%	8.46%	11.29%	11.60%
Entergy Corporation	ETR	4.10%	0.95	12.56%	8.46%	12.13%	12.24%
Evergy, Inc.	EVRG	4.10%	0.90	12.56%	8.46%	11.71%	11.92%
IDACORP, Inc.	IDA	4.10%	0.85	12.56%	8.46%	11.29%	11.60%
NextEra Energy, Inc.	NEE	4.10%	0.95	12.56%	8.46%	12.13%	12.24%
NorthWestern Corporation	NWE	4.10%	0.95	12.56%	8.46%	12.13%	12.24%
OGE Energy Corporation	OGE	4.10%	1.05	12.56%	8.46%	12.98%	12.87%
Pinnacle West Capital Corporation	PNW	4.10%	0.95	12.56%	8.46%	12.13%	12.24%
Portland General Electric Company	POR	4.10%	0.90	12.56%	8.46%	11.71%	11.92%
Southern Company	SO	4.10%	0.90	12.56%	8.46%	11.71%	11.92%
Xcel Energy Inc.	XEL	4.10%	0.85	12.56%	8.46%	11.29%	11.60%
Mean						11.66%	11.88%
Median						11.71%	11.92%

Notes:
[1] Blue Chip Financial Forecasts, Vol. 42, No. 12, December 1, 2023, at 14
[2] Value Line
[3] Market Return
[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 AND 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)	CAPM ROE (K)	ECAPM ROE (K)
ALLETE, Inc.	ALE	4.77%	0.83	12.56%	7.78%	11.20%	11.54%
Alliant Energy Corporation	LNT	4.77%	0.79	12.56%	7.78%	10.92%	11.33%
Ameren Corporation	AEE	4.77%	0.75	12.56%	7.78%	10.61%	11.10%
American Electric Power Company, Inc.	AEP	4.77%	0.76	12.56%	7.78%	10.65%	11.13%
Avista Corporation	AVA	4.77%	0.76	12.56%	7.78%	10.70%	11.16%
CMS Energy Corporation	CMS	4.77%	0.75	12.56%	7.78%	10.58%	11.08%
Duke Energy Corporation	DUK	4.77%	0.72	12.56%	7.78%	10.34%	10.89%
Entergy Corporation	ETR	4.77%	0.86	12.56%	7.78%	11.46%	11.73%
Evergy, Inc.	EVRG	4.77%	0.78	12.56%	7.78%	10.85%	11.27%
IDACORP, Inc.	IDA	4.77%	0.80	12.56%	7.78%	10.99%	11.38%
NextEra Energy, Inc.	NEE	4.77%	0.81	12.56%	7.78%	11.10%	11.46%
NorthWestern Corporation	NWE	4.77%	0.87	12.56%	7.78%	11.52%	11.78%
OGE Energy Corporation	OGE	4.77%	0.92	12.56%	7.78%	11.90%	12.06%
Pinnacle West Capital Corporation	PNW	4.77%	0.82	12.56%	7.78%	11.14%	11.50%
Portland General Electric Company	POR	4.77%	0.79	12.56%	7.78%	10.92%	11.33%
Southern Company	SO	4.77%	0.77	12.56%	7.78%	10.80%	11.24%
Xcel Energy Inc.	XEL	4.77%	0.74	12.56%	7.78%	10.51%	11.02%
Mean						10.95%	11.35%
Median						10.92%	11.33%

Notes:
[1] Bloomberg Professional 30-day average as of November 30, 2023
[2] Bloomberg Professional
[3] Market Return
[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 AND 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	Near-term projected 30-year U.S. Treasury bond yield (Q1 2024 - Q1 2025)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM ROE (K)	ECAPM ROE (K)
ALLETE, Inc.	ALE	4.48%	0.83	12.56%	8.08%	11.15%	11.50%
Alliant Energy Corporation	LNT	4.48%	0.79	12.56%	8.08%	10.85%	11.28%
Ameren Corporation	AEE	4.48%	0.75	12.56%	8.08%	10.53%	11.04%
American Electric Power Company, Inc.	AEP	4.48%	0.76	12.56%	8.08%	10.58%	11.07%
Avista Corporation	AVA	4.48%	0.76	12.56%	8.08%	10.63%	11.11%
CMS Energy Corporation	CMS	4.48%	0.75	12.56%	8.08%	10.51%	11.02%
Duke Energy Corporation	DUK	4.48%	0.72	12.56%	8.08%	10.26%	10.83%
Entergy Corporation	ETR	4.48%	0.86	12.56%	8.08%	11.42%	11.70%
Evergy, Inc.	EVRG	4.48%	0.78	12.56%	8.08%	10.78%	11.23%
IDACORP, Inc.	IDA	4.48%	0.80	12.56%	8.08%	10.93%	11.34%
NextEra Energy, Inc.	NEE	4.48%	0.81	12.56%	8.08%	11.05%	11.42%
NorthWestern Corporation	NWE	4.48%	0.87	12.56%	8.08%	11.48%	11.75%
OGE Energy Corporation	OGE	4.48%	0.92	12.56%	8.08%	11.87%	12.04%
Pinnacle West Capital Corporation	PNW	4.48%	0.82	12.56%	8.08%	11.09%	11.46%
Portland General Electric Company	POR	4.48%	0.79	12.56%	8.08%	10.86%	11.28%
Southern Company	SO	4.48%	0.77	12.56%	8.08%	10.74%	11.19%
Xcel Energy Inc.	XEL	4.48%	0.74	12.56%	8.08%	10.43%	10.96%
Mean						10.89%	11.31%
Median						10.85%	11.28%

Notes:
[1] Blue Chip Financial Forecasts, Vol. 42, No. 12, December 1, 2023, at 2
[2] Bloomberg Professional
[3] Market Return
[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 AND 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	Projected 30-year U.S. Treasury bond yield (2025 - 2029)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM ROE (K)	ECAPM ROE (K)
ALLETE, Inc.	ALE	4.10%	0.83	12.56%	8.46%	11.08%	11.45%
Alliant Energy Corporation	LNT	4.10%	0.79	12.56%	8.46%	10.77%	11.22%
Ameren Corporation	AEE	4.10%	0.75	12.56%	8.46%	10.44%	10.97%
American Electric Power Company, Inc.	AEP	4.10%	0.76	12.56%	8.46%	10.49%	11.01%
Avista Corporation	AVA	4.10%	0.76	12.56%	8.46%	10.54%	11.04%
CMS Energy Corporation	CMS	4.10%	0.75	12.56%	8.46%	10.41%	10.95%
Duke Energy Corporation	DUK	4.10%	0.72	12.56%	8.46%	10.15%	10.75%
Entergy Corporation	ETR	4.10%	0.86	12.56%	8.46%	11.36%	11.66%
Evergy, Inc.	EVRG	4.10%	0.78	12.56%	8.46%	10.70%	11.16%
IDACORP, Inc.	IDA	4.10%	0.80	12.56%	8.46%	10.85%	11.28%
NextEra Energy, Inc.	NEE	4.10%	0.81	12.56%	8.46%	10.97%	11.37%
NorthWestern Corporation	NWE	4.10%	0.87	12.56%	8.46%	11.43%	11.71%
OGE Energy Corporation	OGE	4.10%	0.92	12.56%	8.46%	11.84%	12.02%
Pinnacle West Capital Corporation	PNW	4.10%	0.82	12.56%	8.46%	11.02%	11.41%
Portland General Electric Company	POR	4.10%	0.79	12.56%	8.46%	10.78%	11.22%
Southern Company	SO	4.10%	0.77	12.56%	8.46%	10.65%	11.13%
Xcel Energy Inc.	XEL	4.10%	0.74	12.56%	8.46%	10.33%	10.89%
Mean						10.81%	11.25%
Median						10.77%	11.22%

Notes:
[1] Blue Chip Financial Forecasts, Vol. 42, No. 12, December 1, 2023, at 14
[2] Bloomberg Professional
[3] Market Return
[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 AND LONG-TERM VALUE LINE 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)	CAPM ROE (K)	ECAPM ROE (K)
ALLETE, Inc.	ALE	4.77%	0.79	12.56%	7.78%	10.88%	11.30%
Alliant Energy Corporation	LNT	4.77%	0.75	12.56%	7.78%	10.61%	11.10%
Ameren Corporation	AEE	4.77%	0.73	12.56%	7.78%	10.42%	10.95%
American Electric Power Company, Inc.	AEP	4.77%	0.68	12.56%	7.78%	10.03%	10.66%
Avista Corporation	AVA	4.77%	0.79	12.56%	7.78%	10.88%	11.30%
CMS Energy Corporation	CMS	4.77%	0.69	12.56%	7.78%	10.14%	10.75%
Duke Energy Corporation	DUK	4.77%	0.67	12.56%	7.78%	9.95%	10.60%
Entergy Corporation	ETR	4.77%	0.75	12.56%	7.78%	10.57%	11.07%
Evergy, Inc.	EVRG	4.77%	0.95	12.56%	7.78%	12.17%	12.26%
IDACORP, Inc.	IDA	4.77%	0.73	12.56%	7.78%	10.46%	10.98%
NextEra Energy, Inc.	NEE	4.77%	0.73	12.56%	7.78%	10.46%	10.98%
NorthWestern Corporation	NWE	4.77%	0.75	12.56%	7.78%	10.57%	11.07%
OGE Energy Corporation	OGE	4.77%	0.93	12.56%	7.78%	12.01%	12.15%
Pinnacle West Capital Corporation	PNW	4.77%	0.74	12.56%	7.78%	10.49%	11.01%
Portland General Electric Company	POR	4.77%	0.75	12.56%	7.78%	10.61%	11.10%
Southern Company	SO	4.77%	0.66	12.56%	7.78%	9.87%	10.54%
Xcel Energy Inc.	XEL	4.77%	0.66	12.56%	7.78%	9.87%	10.54%
Mean						10.59%	11.08%
Median						10.49%	11.01%

Notes:
[1] Bloomberg Professional 30-day average as of November 30, 2023
[2] Source: LT Beta
[3] Market Return
[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 AND LONG-TERM VALUE LINE 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 (Q1 2024 - Q1 2025)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM ROE (K)	ECAPM ROE (K)
ALLETE, Inc.	ALE	4.48%	0.79	12.56%	8.08%	10.82%	11.25%
Alliant Energy Corporation	LNT	4.48%	0.75	12.56%	8.08%	10.54%	11.04%
Ameren Corporation	AEE	4.48%	0.73	12.56%	8.08%	10.34%	10.89%
American Electric Power Company, Inc.	AEP	4.48%	0.68	12.56%	8.08%	9.93%	10.59%
Avista Corporation	AVA	4.48%	0.79	12.56%	8.08%	10.82%	11.25%
CMS Energy Corporation	CMS	4.48%	0.69	12.56%	8.08%	10.05%	10.68%
Duke Energy Corporation	DUK	4.48%	0.67	12.56%	8.08%	9.85%	10.53%
Entergy Corporation	ETR	4.48%	0.75	12.56%	8.08%	10.50%	11.01%
Evergy, Inc.	EVRG	4.48%	0.95	12.56%	8.08%	12.15%	12.25%
IDACORP, Inc.	IDA	4.48%	0.73	12.56%	8.08%	10.38%	10.92%
NextEra Energy, Inc.	NEE	4.48%	0.73	12.56%	8.08%	10.38%	10.92%
NorthWestern Corporation	NWE	4.48%	0.75	12.56%	8.08%	10.50%	11.01%
OGE Energy Corporation	OGE	4.48%	0.93	12.56%	8.08%	11.99%	12.13%
Pinnacle West Capital Corporation	PNW	4.48%	0.74	12.56%	8.08%	10.42%	10.95%
Portland General Electric Company	POR	4.48%	0.75	12.56%	8.08%	10.54%	11.04%
Southern Company	SO	4.48%	0.66	12.56%	8.08%	9.77%	10.47%
Xcel Energy Inc.	XEL	4.48%	0.66	12.56%	8.08%	9.77%	10.47%
Mean						10.51%	11.02%
Median						10.42%	10.95%

Notes:
[1] Blue Chip Financial Forecasts, Vol. 42, No. 12, December 1, 2023, at 2
[2] Source: LT Beta
[3] Market Return
[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 AND LONG-TERM VALUE LINE 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 (2025 - 2029)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM ROE (K)	ECAPM ROE (K)
ALLETE, Inc.	ALE	4.10%	0.79	12.56%	8.46%	10.74%	11.19%
Alliant Energy Corporation	LNT	4.10%	0.75	12.56%	8.46%	10.44%	10.97%
Ameren Corporation	AEE	4.10%	0.73	12.56%	8.46%	10.23%	10.81%
American Electric Power Company, Inc.	AEP	4.10%	0.68	12.56%	8.46%	9.81%	10.49%
Avista Corporation	AVA	4.10%	0.79	12.56%	8.46%	10.74%	11.19%
CMS Energy Corporation	CMS	4.10%	0.69	12.56%	8.46%	9.93%	10.59%
Duke Energy Corporation	DUK	4.10%	0.67	12.56%	8.46%	9.72%	10.43%
Entergy Corporation	ETR	4.10%	0.75	12.56%	8.46%	10.40%	10.94%
Evergy, Inc.	EVRG	4.10%	0.95	12.56%	8.46%	12.13%	12.24%
IDACORP, Inc.	IDA	4.10%	0.73	12.56%	8.46%	10.27%	10.84%
NextEra Energy, Inc.	NEE	4.10%	0.73	12.56%	8.46%	10.27%	10.84%
NorthWestern Corporation	NWE	4.10%	0.75	12.56%	8.46%	10.40%	10.94%
OGE Energy Corporation	OGE	4.10%	0.93	12.56%	8.46%	11.96%	12.11%
Pinnacle West Capital Corporation	PNW	4.10%	0.74	12.56%	8.46%	10.32%	10.88%
Portland General Electric Company	POR	4.10%	0.75	12.56%	8.46%	10.44%	10.97%
Southern Company	SO	4.10%	0.66	12.56%	8.46%	9.64%	10.37%
Xcel Energy Inc.	XEL	4.10%	0.66	12.56%	8.46%	9.64%	10.37%
Mean						10.42%	10.95%
Median						10.32%	10.88%

Notes:

[1] Blue Chip Financial Forecasts, Vol. 42, No. 12, December 1, 2023, at 14
[2] Source: LT Beta
[3] Market Return
[4] Equals [3]-[1]
[5] Equals [1] + [2] x [4]
[6] Equals [1] + 0.25 x ([4]) + 0.75 x ([2] x [4])

Docket No. UE 433
Exhibit PAC/408
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Ann E. Bulkley

Long-Term Beta Coefficient

February 2024

HISTORICAL VALUE LINE BETA

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	Ticker	12/31/2013	12/31/2014	12/31/2015	12/31/2016	12/31/2017	12/31/2018	12/31/2019	12/31/2020	12/31/2021	12/31/2022	Average
ALLETE, Inc.	ALE	0.75	0.80	0.80	0.75	0.80	0.65	0.65	0.85	0.90	0.90	0.79
Alliant Energy Corporation	LNT	0.75	0.80	0.80	0.70	0.70	0.60	0.60	0.85	0.85	0.85	0.75
Ameren Corporation	AEE	0.80	0.75	0.75	0.65	0.70	0.55	0.55	0.85	0.80	0.85	0.73
American Electric Power Company, Inc.	AEP	0.70	0.70	0.70	0.65	0.65	0.55	0.55	0.75	0.75	0.75	0.68
Avista Corporation	AVA	0.75	0.80	0.80	0.70	0.75	0.65	0.60	0.95	0.95	0.90	0.79
CMS Energy Corporation	CMS	0.70	0.70	0.75	0.65	0.65	0.55	0.50	0.80	0.80	0.80	0.69
Duke Energy Corporation	DUK	0.65	0.60	0.65	0.60	0.60	0.50	0.50	0.85	0.85	0.85	0.67
Entergy Corporation	ETR	0.70	0.70	0.70	0.65	0.65	0.60	0.60	0.95	0.95	0.95	0.75
Evergy, Inc.	EVRG						NMF	NMF	1.00	0.95	0.90	0.95
IDACORP, Inc.	IDA	0.75	0.80	0.80	0.75	0.70	0.55	0.55	0.80	0.80	0.80	0.73
NextEra Energy, Inc.	NEE	0.70	0.70	0.75	0.65	0.65	0.55	0.55	0.90	0.90	0.95	0.73
NorthWestern Corporation	NWE	0.70	0.70	0.70	0.70	0.70	0.55	0.60	0.95	0.95	0.90	0.75
OGE Energy Corporation	OGE	0.85	0.90	0.95	0.90	0.95	0.85	0.75	1.10	1.05	1.00	0.93
Pinnacle West Capital Corporation	PNW	0.75	0.70	0.75	0.70	0.70	0.55	0.50	0.90	0.90	0.90	0.74
Portland General Electric Company	POR	0.75	0.80	0.80	0.70	0.70	0.60	0.55	0.85	0.90	0.85	0.75
Southern Company	SO	0.55	0.55	0.60	0.55	0.55	0.50	0.50	0.90	0.95	0.90	0.66
Xcel Energy Inc.	XEL	0.65	0.65	0.65	0.60	0.60	0.50	0.50	0.80	0.80	0.80	0.66
Mean		0.72	0.73	0.75	0.68	0.69	0.58	0.57	0.89	0.89	0.87	0.75

Notes:
[1] Value Line, December 26, 2013
[2] Value Line, December 31, 2014
[3] Value Line, December 30, 2015
[4] Value Line, December 29, 2016
[5] Value Line, December 28, 2017
[6] Value Line, December 27, 2018
[7] Value Line, December 26, 2019
[8] Value Line, December 30, 2020
[9] Value Line, December 29, 2021
[10] Value Line, December 30, 2022
[11] Average ([1] - [10])

Docket No. UE 433
Exhibit PAC/409
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Ann E. Bulkley

Market Return

February 2024

MARKET RISK PREMIUM DERIVED FROM S&P 500 INDEX

[1] Estimate of the S&P 500 Dividend Yield	1.69%
[2] Estimate of the S&P 500 Growth Rate	10.78%
[3] S&P 500 Estimated Required Market Return	12.56%

		[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	Bloomberg Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
LyondellBasell Industries NV	LYB	324.362	95.1	30,846.83	0.11%	5.26%	0.01%	8.00%	0.01%
American Express Co	AXP	728.746	170.77	124,447.95	0.42%	1.41%	0.01%	14.01%	0.06%
Verizon Communications Inc	VZ	4204.102	38.33	161,143.23		6.94%			
Broadcom Inc	AVGO	469.426	925.73	434,561.73	1.48%	1.99%	0.03%	13.89%	0.21%
Boeing Co/The	BA	604.977	231.63	140,130.82				183.61%	
Caterpillar Inc	CAT	509.085	250.72	127,637.79	0.43%	2.07%	0.01%	20.00%	0.09%
JPMorgan Chase & Co	JPM	2891.008	156.08	451,228.53	1.54%	2.69%	0.04%	1.00%	0.02%
Chevron Corp	CVX	1887.749	143.6	271,080.76	0.92%	4.21%	0.04%	7.27%	0.07%
Coca-Cola Co/The	KO	4323.414	58.44	252,660.31	0.86%	3.15%	0.03%	6.51%	0.06%
AbbVie Inc	ABBV	1765.537	142.39	251,394.81	0.86%	4.35%	0.04%	0.19%	0.00%
Walt Disney Co/The	DIS	1830.316	92.69	169,651.99	0.58%	0.65%	0.00%	18.88%	0.11%
FleetCor Technologies Inc	FLT	72.204	240.5	17,365.06	0.06%			12.92%	0.01%
Extra Space Storage Inc	EXR	211.278	130.17	27,502.06	0.09%	4.98%	0.00%	1.10%	0.00%
Exxon Mobil Corp	XOM	4006.133	102.74	411,590.10		3.70%		45.59%	
Phillips 66	PSX	439.956	128.89	56,705.93	0.19%	3.26%	0.01%	15.21%	0.03%
General Electric Co	GE	1088.386	121.8	132,565.41		0.26%		22.50%	
HP Inc	HPQ	988.269	29.34	28,995.81	0.10%	3.76%	0.00%	3.00%	0.00%
Home Depot Inc/The	HD	995.262	313.49	312,004.68	1.06%	2.67%	0.03%	1.69%	0.02%
Monolithic Power Systems Inc	MPWR	47.912	548.72	26,290.27	0.09%	0.73%	0.00%	8.00%	0.01%
International Business Machines Corp	IBM	913.119	158.56	144,784.15	0.49%	4.19%	0.02%	2.77%	0.01%
Johnson & Johnson	JNJ	2407.279	154.66	372,309.77	1.27%	3.08%	0.04%	3.86%	0.05%
Lululemon Athletica Inc	LULU	121.425	446.8	54,252.69	0.18%			16.00%	0.03%
McDonald's Corp	MCD	725.342	281.84	204,430.39	0.70%	2.37%	0.02%	9.34%	0.07%
Merck & Co Inc	MRK	2534.023	102.48	259,686.68	0.88%	3.01%	0.03%	9.08%	0.08%
3M Co	MMM	552.317	99.07	54,718.05	0.19%	6.06%	0.01%	4.00%	0.01%
American Water Works Co Inc	AWK	194.705	131.84	25,669.91	0.09%	2.15%	0.00%	8.00%	0.01%
Bank of America Corp	BAC	7913.732	30.49	241,289.69		3.15%		-5.00%	
Pfizer Inc	PFE	5646.413	30.47	172,046.20		5.38%		50.40%	
Procter & Gamble Co/The	PG	2356.886	153.52	361,829.14	1.23%	2.45%	0.03%	7.51%	0.09%
AT&T Inc	T	7150.02	16.57	118,475.83	0.40%	6.70%	0.03%	3.36%	0.01%
Travelers Cos Inc/The	TRV	228.399	180.62	41,253.43	0.14%	2.21%	0.00%	15.33%	0.02%
RTX Corp	RTX	1437.901	81.48	117,160.17	0.40%	2.90%	0.01%	8.61%	0.03%
Analog Devices Inc	ADI	496.262	182.5199	90,577.69	0.31%	1.88%	0.01%	4.50%	0.01%
Walmart Inc	WMT	2692.234	155.69	419,153.91	1.43%	1.46%	0.02%	3.00%	0.04%
Cisco Systems Inc	CSCO	4063.476	48.38	196,590.97	0.67%	3.22%	0.02%	10.00%	0.07%
Intel Corp	INTC	4216	44.7	188,455.20		1.12%		-1.82%	
General Motors Co	GM	1369.481	31.6	43,275.60		1.14%		-4.65%	
Microsoft Corp	MSFT	7432.262	378.91	2,816,158.39	9.59%	0.79%	0.08%	15.72%	1.51%
Dollar General Corp	DG	219.476	131.12	28,777.69		1.80%		-2.50%	
Cigna Group/The	CI	292.62	262.88	76,923.95	0.26%	1.87%	0.00%	9.80%	0.03%
Kinder Morgan Inc	KMI	2222.774	17.57	39,054.14	0.13%	6.43%	0.01%	2.00%	0.00%
Citigroup Inc	C	1913.882	46.1	88,229.96		4.60%		-9.70%	
American International Group Inc	AIG	702.04	65.81	46,201.25	0.16%	2.19%	0.00%	10.00%	0.02%
Altria Group Inc	MO	1768.647	42.04	74,353.92	0.25%	9.32%	0.02%	4.50%	0.01%
HCA Healthcare Inc	HCA	267.661	250.48	67,043.73	0.23%	0.96%	0.00%	7.56%	0.02%
International Paper Co	IP	346.017	36.94	12,781.87		5.01%		-2.00%	
Hewlett Packard Enterprise Co	HPE	1283	16.91	21,695.53	0.07%	3.08%	0.00%	3.03%	0.00%
Abbott Laboratories	ABT	1736.059	104.29	181,053.59	0.62%	1.96%	0.01%	3.27%	0.02%
Aflac Inc	AFL	584.38	82.71	48,334.07	0.16%	2.42%	0.00%	8.04%	0.01%
Air Products and Chemicals Inc	APD	222.208	270.55	60,118.37	0.20%	2.59%	0.01%	12.55%	0.03%
Royal Caribbean Cruises Ltd	RCL	256.235	107.46	27,535.01					
Hess Corp	HES	307.152	140.56	43,173.29	0.15%	1.25%	0.00%	13.00%	0.02%
Archer-Daniels-Midland Co	ADM	533.381	73.73	39,326.18		2.44%		-7.07%	
Automatic Data Processing Inc	ADP	411.305	229.92	94,567.25	0.32%	2.44%	0.01%	16.00%	0.05%
Verisk Analytics Inc	VRSK	144.987	241.43	35,004.21	0.12%	0.56%	0.00%	12.15%	0.01%
AutoZone Inc	AZO	17.634	2609.93	46,023.51	0.16%			13.72%	0.02%
Linde PLC	LIN	484.89	412.4952	200,014.80	0.68%	1.24%	0.01%	14.00%	0.10%
Avery Dennison Corp	AVY	80.531	194.5	15,663.28	0.05%	1.67%	0.00%	7.00%	0.00%
Enphase Energy Inc	ENPH	136.551	101.02	13,794.38				28.59%	
MSCI Inc	MSCI	79.091	520.85	41,194.55	0.14%	1.06%	0.00%	14.48%	0.02%
Ball Corp	BALL	315.301	55.29	17,432.99	0.06%	1.45%	0.00%	10.30%	0.01%
Axon Enterprise Inc	AXON	74.934	229.87	17,225.08					
Ceridian HCM Holding Inc	CDAY	156.127	68.9	10,757.15					
Carrier Global Corp	CARR	839.047	51.96	43,596.88	0.15%	1.42%	0.00%	10.80%	0.02%
Bank of New York Mellon Corp/The	BK	769.073	48.32	37,161.61	0.13%	3.48%	0.00%	10.00%	0.01%
Otis Worldwide Corp	OTIS	409.259	85.79	35,110.33	0.12%	1.59%	0.00%	9.00%	0.01%
Baxter International Inc	BAX	507.324	36.08	18,304.25		3.22%		-1.17%	
Becton Dickinson & Co	BDX	290.405	236.18	68,587.85		1.61%		-2.02%	
Berkshire Hathaway Inc	BRK/B	1308.414	360	471,029.04					
Best Buy Co Inc	BBY	217.638	70.94	15,439.24	0.05%	5.19%	0.00%	2.93%	0.00%
Boston Scientific Corp	BSX	1464.983	55.89	81,877.90	0.28%			12.10%	0.03%
Bristol-Myers Squibb Co	BMY	2034.758	49.38	100,476.35	0.34%	4.62%	0.02%	9.92%	0.03%
Brown-Forman Corp	BF/B	310.136	58.74	18,217.39	0.06%	1.48%	0.00%	6.42%	0.00%
Coterra Energy Inc	CTRA	752.192	26.25	19,745.04		3.05%		55.04%	
Campbell Soup Co	CPB	297.622	40.18	11,958.45	0.04%	3.68%	0.00%	2.81%	0.00%
Hilton Worldwide Holdings Inc	HLT	256.44	167.52	42,958.83	0.15%	0.36%	0.00%	17.09%	0.03%
Carnival Corp	CCL	1119.445	15.06	16,858.84					
Qorvo Inc	QRVO	97.346	96.5	9,393.89	0.03%			10.04%	0.00%
UDR Inc	UDR	328.928	33.4	10,986.20	0.04%	5.03%	0.00%	6.08%	0.00%
Clorox Co/The	CLX	124.059	143.35	17,783.86	0.06%	3.35%	0.00%	11.53%	0.01%
Paycom Software Inc	PAYC	60.228	181.66	10,941.02	0.04%	0.83%	0.00%	15.19%	0.01%
CMS Energy Corp	CMS	291.764	56.76	16,560.52	0.06%	3.44%	0.00%	7.75%	0.00%
Colgate-Palmolive Co	CL	823.372	78.77	64,857.01	0.22%	2.44%	0.01%	7.21%	0.02%
EPAM Systems Inc	EPAM	57.7	258.19	14,897.56	0.05%			4.87%	0.00%
Comerica Inc	CMA	131.873	45.22	5,963.30	0.02%	6.28%	0.00%	10.63%	0.00%

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Name	Ticker	Shares Outst'g	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Bloomberg Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
Conagra Brands Inc	CAG	477.968	28.29	13,521.71	0.05%	4.95%	0.00%	0.84%	0.00%
Airbnb Inc	ABNB	434.745	126.34	54,925.68	0.19%			18.20%	0.03%
Consolidated Edison Inc	ED	344.924	90.11	31,081.10	0.11%	3.60%	0.00%	4.88%	0.01%
Corning Inc	GLW	853.175	28.49	24,306.96	0.08%	3.93%	0.00%	1.57%	0.00%
Cummins Inc	CMI	141.745	224.16	31,773.56	0.11%	3.00%	0.00%	9.15%	0.01%
Caesars Entertainment Inc	CZR	215.711	44.72	9,646.60				110.92%	
Danaher Corp	DHR	738.927	223.31	165,009.79		0.48%		-7.03%	
Target Corp	TGT	461.662	133.81	61,774.99	0.21%	3.29%	0.01%	0.15%	0.00%
Deere & Co	DE	288.001	364.41	104,950.44	0.36%	1.48%	0.01%	3.96%	0.01%
Dominion Energy Inc	D	836.773	45.34	37,939.29		5.89%		-0.72%	
Dover Corp	DOV	139.89	141.16	19,746.87	0.07%	1.45%	0.00%	10.00%	0.01%
Alliant Energy Corp	LNT	252.719	50.57	12,780.00	0.04%	3.58%	0.00%	6.26%	0.00%
Steel Dynamics Inc	STLD	161.816	119.13	19,277.14		1.43%		-13.17%	
Duke Energy Corp	DUK	771	92.28	71,147.88	0.24%	4.44%	0.01%	6.06%	0.01%
Regency Centers Corp	REG	184.576	62.78	11,587.68	0.04%	4.27%	0.00%	4.64%	0.00%
Eaton Corp PLC	ETN	399.3	227.69	90,916.62	0.31%	1.51%	0.00%	15.00%	0.05%
Ecolab Inc	ECL	285.14	191.73	54,669.89	0.19%	1.11%	0.00%	16.00%	0.03%
Revvity Inc	RVTY	123.407	88.9	10,970.88		0.31%		-26.69%	
Emerson Electric Co	EMR	570.1	88.9	50,681.89	0.17%	2.36%	0.00%	12.01%	0.02%
EOG Resources Inc	EOG	583.15	123.07	71,768.27	0.24%	2.96%	0.01%	17.83%	0.04%
Aon PLC	AON	200.216	328.49	65,768.95	0.22%	0.75%	0.00%	11.58%	0.03%
Entergy Corp	ETR	211.456	101.41	21,443.75	0.07%	4.46%	0.00%	6.22%	0.00%
Equifax Inc	EFX	123.217	217.71	26,825.57	0.09%	0.72%	0.00%	12.33%	0.01%
EQT Corp	EQT	411.332	39.96	16,436.83		1.58%		20.04%	
IQVIA Holdings Inc	IQV	182.5	214.1	39,073.25				-13.67%	
Gartner Inc	IT	77.949	434.84	33,895.34	0.12%			7.35%	0.01%
FedEx Corp	FDX	251.42	258.83	65,075.04	0.22%	1.95%	0.00%	14.50%	0.03%
FMC Corp	FMC	124.759	53.66	6,694.57		4.32%		-4.00%	
Brown & Brown Inc	BRO	284.598	74.74	21,270.85	0.07%	0.70%	0.00%	11.00%	0.01%
Ford Motor Co	F	3932.102	10.26	40,343.37		5.85%		-2.52%	
NextEra Energy Inc	NEE	2023.714	58.51	118,407.51	0.40%	3.20%	0.01%	8.10%	0.03%
Franklin Resources Inc	BEN	494.584	24.8	12,265.68		4.84%		-9.00%	
Garmin Ltd	GRMN	191.331	122.24	23,388.30	0.08%	2.39%	0.00%	5.60%	0.00%
Freeport-McMoRan Inc	FCX	1433.977	37.32	53,516.02		1.61%		-15.66%	
Dexcom Inc	DXCM	386.374	115.52	44,633.92				30.59%	
General Dynamics Corp	GD	272.897	246.97	67,397.37	0.23%	2.14%	0.00%	10.40%	0.02%
General Mills Inc	GIS	581.279	63.66	37,004.22	0.13%	3.71%	0.00%	8.00%	0.01%
Genuine Parts Co	GPC	140.197	132.78	18,615.36	0.06%	2.86%	0.00%	9.49%	0.01%
Atmos Energy Corp	ATO	148.496	113.81	16,900.33	0.06%	2.83%	0.00%	7.25%	0.00%
WW Grainger Inc	GWW	49.634	786.19	39,021.75		0.95%			
Halliburton Co	HAL	895.052	37.03	33,143.78		1.73%		24.14%	
L3Harris Technologies Inc	LHX	189.54	190.81	36,166.13	0.12%	2.39%	0.00%	3.50%	0.00%
Healthpeak Properties Inc	PEAK	547.074	17.32	9,475.32	0.03%	6.93%	0.00%	1.24%	0.00%
Insulet Corp	PODD	69.828	189.09	13,203.78				41.08%	
Catalent Inc	CTLT	180.272	38.85	7,003.57	0.02%			9.24%	0.00%
Fortive Corp	FTV	351.434	68.98	24,241.92	0.08%	0.46%	0.00%	8.68%	0.01%
Hershey Co/The	HSY	149.885	187.92	28,166.39	0.10%	2.54%	0.00%	9.00%	0.01%
Synchrony Financial	SYF	413.804	32.36	13,390.70		3.09%			
Hormel Foods Corp	HRL	546.481	30.59	16,716.85	0.06%	3.69%	0.00%	1.08%	0.00%
Arthur J Gallagher & Co	AJG	215.9	249	53,759.10	0.18%	0.88%	0.00%	14.11%	0.03%
Mondelez International Inc	MDLZ	1360.896	71.06	96,705.27	0.33%	2.39%	0.01%	9.17%	0.03%
CenterPoint Energy Inc	CNP	629.432	28.27	17,794.04	0.06%	2.83%	0.00%	8.02%	0.00%
Humana Inc	HUM	123.111	484.86	59,691.60	0.20%	0.73%	0.00%	12.32%	0.03%
Willis Towers Watson PLC	WTW	103.26	246.3	25,432.94	0.09%	1.36%	0.00%	11.19%	0.01%
Illinois Tool Works Inc	ITW	300.886	242.21	72,877.60	0.25%	2.31%	0.01%	3.91%	0.01%
CDW Corp/DE	CDW	133.96	210.88	28,249.48	0.10%	1.18%	0.00%	13.10%	0.01%
Trane Technologies PLC	TT	227.557	225.41	51,293.62	0.17%	1.33%	0.00%	13.29%	0.02%
Interpublic Group of Cos Inc/The	IPG	383.004	30.74	11,773.54	0.04%	4.03%	0.00%	5.71%	0.00%
International Flavors & Fragrances Inc	IFF	255.279	75.38	19,242.93	0.07%	4.30%	0.00%	5.50%	0.00%
Generac Holdings Inc	GNRC	61.432	117.07	7,191.84	0.02%			5.00%	0.00%
NXP Semiconductors NV	NXPI	257.763	204.08	52,604.27		1.99%		34.00%	
Kellanova	K	342.52	52.54	17,996.00	0.06%	4.26%	0.00%	1.69%	0.00%
Broadridge Financial Solutions Inc	BR	117.647	193.82	22,802.34		1.65%			
Kimberly-Clark Corp	KMB	337.941	123.73	41,813.44	0.14%	3.81%	0.01%	9.64%	0.01%
Kimco Realty Corp	KIM	619.892	19.32	11,976.31	0.04%	4.97%	0.00%	4.35%	0.00%
Oracle Corp	ORCL	2739.376	116.21	318,342.88	1.08%	1.38%	0.01%	14.45%	0.16%
Kroger Co/The	KR	719.316	44.27	31,844.12	0.11%	2.62%	0.00%	4.21%	0.00%
Lennar Corp	LEN	250.152	127.92	31,999.44	0.11%	1.17%	0.00%	1.00%	0.00%
Eli Lilly & Co	LLY	949.307	591.04	561,078.41		0.76%		21.47%	
Bath & Body Works Inc	BBWI	227.381	32.62	7,417.17	0.03%	2.45%	0.00%	6.51%	0.00%
Charter Communications Inc	CHTR	147.92	400.13	59,187.23	0.20%			12.31%	0.02%
Loews Corp	L	223.251	70.29	15,692.31		0.36%			
Lowe's Cos Inc	LOW	575.113	198.83	114,349.72		2.21%		20.20%	
Hubbell Inc	HUBB	53.622	300	16,086.60		1.63%			
IDEX Corp	IEX	75.626	201.68	15,252.25	0.05%	1.27%	0.00%	11.00%	0.01%
Marsh & McLennan Cos Inc	MMC	493.072	199.42	98,328.42	0.33%	1.42%	0.00%	11.53%	0.04%
Masco Corp	MAS	224.501	60.55	13,593.54	0.05%	1.88%	0.00%	4.36%	0.00%
S&P Global Inc	SPGI	316.8	415.83	131,734.94	0.45%	0.87%	0.00%	13.66%	0.06%
Medtronic PLC	MDT	1329.654	79.27	105,401.67	0.36%	3.48%	0.01%	4.33%	0.02%
Viatris Inc	VTRS	1199.671	9.18	11,012.98		5.23%		-2.58%	
CVS Health Corp	CVS	1286.897	67.95	87,444.65	0.30%	3.56%	0.01%	6.99%	0.02%
DuPont de Nemours Inc	DD	430.042	71.54	30,765.20	0.10%	2.01%	0.00%	11.43%	0.01%
Micron Technology Inc	MU	1098.034	76.12	83,582.35		0.60%		-11.00%	
Motorola Solutions Inc	MSI	165.968	322.87	53,586.09	0.18%	1.21%	0.00%	10.82%	0.02%
Cboe Global Markets Inc	CBOE	105.556	182.19	19,231.25	0.07%	1.21%	0.00%	10.21%	0.01%
Laboratory Corp of America Holdings	LH	84.9	216.91	18,415.66		1.33%		-32.45%	
Newmont Corp	NEM	1152.492	40.19	46,318.65	0.16%	3.98%	0.01%	11.58%	0.02%
NIKE Inc	NKE	1224.013	109.9	134,519.03	0.46%	1.35%	0.01%	16.07%	0.07%
NiSource Inc	NI	413.415	25.64	10,599.96	0.04%	3.90%	0.00%	7.65%	0.00%
Norfolk Southern Corp	NSC	226.136	218.16	49,333.83	0.17%	2.48%	0.00%	0.73%	0.00%
Principal Financial Group Inc	PFG	238.412	73.83	17,601.96	0.06%	3.63%	0.00%	8.98%	0.01%
Eversource Energy	ES	349.086	59.41	20,739.20	0.07%	4.54%	0.00%	5.21%	0.00%
Northrop Grumman Corp	NOC	150.793	475.16	71,650.80	0.24%	1.57%	0.00%	2.53%	0.01%
Wells Fargo & Co	WFC	3631.64	44.59	161,934.83	0.55%	3.14%	0.02%	13.41%	0.07%

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Name	Ticker	Shares Outst'g	Price	Market Capitalization	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Bloomberg Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
Nucor Corp	NUE	245.839	169.97	41,785.25		1.20%		-10.84%	
Occidental Petroleum Corp	OXY	880.371	59.15	52,073.94		1.22%			
Omnicom Group Inc	OMC	197.934	80.63	15,959.42	0.05%	3.47%	0.00%	4.72%	0.00%
ONEOK Inc	OKE	582.551	68.85	40,108.64	0.14%	5.55%	0.01%	6.93%	0.01%
Raymond James Financial Inc	RJF	208.607	105.15	21,935.03		1.71%			
PG&E Corp	PCG	2133.508	17.17	36,632.33	0.12%	0.23%	0.00%	6.26%	0.01%
Parker-Hannifin Corp	PH	128.476	433.18	55,653.23	0.19%	1.37%	0.00%	15.28%	0.03%
Rollins Inc	ROL	484.038	40.74	19,719.71	0.07%	1.47%	0.00%	14.86%	0.01%
PPL Corp	PPL	737.089	26.12	19,252.76	0.07%	3.68%	0.00%	4.20%	0.00%
ConocoPhillips	COP	1187.408	115.57	137,228.74	0.47%	0.50%	0.00%	6.00%	0.03%
PulteGroup Inc	PHM	215.595	88.42	19,062.91	0.06%	0.90%	0.00%	2.04%	0.00%
Pinnacle West Capital Corp	PNW	113.312	74.94	8,491.60	0.03%	4.70%	0.00%	5.95%	0.00%
PNC Financial Services Group Inc/The	PNC	398.341	133.96	53,361.76	0.18%	4.63%	0.01%	12.87%	0.02%
PPG Industries Inc	PPG	235.8	141.99	33,481.24	0.11%	1.83%	0.00%	12.91%	0.01%
Progressive Corp/The	PGR	585.041	164.03	95,964.28		0.24%		39.34%	
Veralto Corp	VLTO	246.308	77.25	19,027.29					
Public Service Enterprise Group Inc	PEG	499.111	62.43	31,159.50	0.11%	3.65%	0.00%	5.47%	0.01%
Robert Half Inc	RHI	105.895	81.98	8,681.27	0.03%	2.34%	0.00%	1.26%	0.00%
Cooper Cos Inc/The	COO	49.524	336.92	16,685.63	0.06%	0.02%	0.00%	7.54%	0.00%
Edison International	EIX	383.568	66.99	25,695.22	0.09%	4.40%	0.00%	4.80%	0.00%
Schlumberger NV	SLB	1423.421	52.04	74,074.83		1.92%		33.41%	
Charles Schwab Corp/The	SCHW	1771.682	61.32	108,639.54	0.37%	1.63%	0.01%	3.60%	0.01%
Sherwin-Williams Co/The	SHW	255.966	278.8	71,363.32	0.24%	0.87%	0.00%	10.90%	0.03%
West Pharmaceutical Services Inc	WST	73.99	350.76	25,952.73	0.09%	0.23%	0.00%	5.80%	0.01%
J M Smucker Co/The	SJM	106.133	109.73	11,645.97	0.04%	3.86%	0.00%	5.95%	0.00%
Snap-on Inc	SNA	52.78	274.69	14,498.14	0.05%	2.71%	0.00%	4.85%	0.00%
AMETEK Inc	AME	230.799	155.23	35,826.93	0.12%	0.64%	0.00%	6.36%	0.01%
Southern Co/The	SO	1091.515	70.98	77,475.73	0.26%	3.94%	0.01%	5.05%	0.01%
Truist Financial Corp	TFC	1333.668	32.14	42,864.09	0.15%	6.47%	0.01%	16.00%	0.02%
Southwest Airlines Co	LUV	596.115	25.57	15,242.66	0.05%	2.82%	0.00%	10.15%	0.01%
W R Berkley Corp	WRB	257.872	72.55	18,708.61	0.06%	0.61%	0.00%	13.00%	0.01%
Stanley Black & Decker Inc	SWK	153.311	90.9	13,935.97	0.05%	3.56%	0.00%	9.00%	0.00%
Public Storage	PSA	175.829	258.76	45,497.51	0.15%	4.64%	0.01%	3.77%	0.01%
Arista Networks Inc	ANET	311.1	219.71	68,351.78	0.23%			19.72%	0.05%
Sysco Corp	SYY	504.372	72.17	36,400.53	0.12%	2.77%	0.00%	13.00%	0.02%
Corteva Inc	CTVA	704.88	45.2	31,860.58	0.11%	1.42%	0.00%	16.17%	0.02%
Texas Instruments Inc	TXN	908.204	152.71	138,691.83	0.47%	3.41%	0.02%	10.00%	0.05%
Textron Inc	TXT	196.005	76.66	15,025.74	0.05%	0.10%	0.00%	11.73%	0.01%
Thermo Fisher Scientific Inc	TMO	386.372	495.76	191,547.78		0.28%		-5.00%	
TJX Cos Inc/The	TJX	1139.677	88.11	100,416.94	0.34%	1.51%	0.01%	6.38%	0.02%
Globe Life Inc	GL	94.119	123.13	11,588.87		0.73%			
Johnson Controls International plc	JCI	680.32	52.8	35,920.90	0.12%	2.80%	0.00%	13.36%	0.02%
Ulta Beauty Inc	ULTA	48.562	425.99	20,686.93	0.07%			6.41%	0.00%
Union Pacific Corp	UNP	609.597	225.27	137,323.92	0.47%	2.31%	0.01%	11.00%	0.05%
Keysight Technologies Inc	KEYS	174.6	135.89	23,726.39	0.08%			1.81%	0.00%
UnitedHealth Group Inc	UNH	924.925	551.09	509,716.92	1.74%	1.36%	0.02%	13.40%	0.23%
Blackstone Inc	BX	710.545	112.37	79,843.94	0.27%	2.85%	0.01%	7.63%	0.02%
Marathon Oil Corp	MRO	585.247	25.43	14,882.83	0.05%	1.73%	0.00%	8.00%	0.00%
Bio-Rad Laboratories Inc	BIO	24.059	304.92	7,336.07	0.02%			4.00%	0.00%
Ventas Inc	VTR	402.381	45.84	18,445.15	0.06%	3.93%	0.00%	8.02%	0.01%
VF Corp	VFC	388.883	16.73	6,506.01	0.02%	2.15%	0.00%	3.10%	0.00%
Vulcan Materials Co	VMC	132.873	213.56	28,376.36		0.81%		23.22%	
Weyerhaeuser Co	WY	730.001	31.35	22,885.53		2.42%			
Whirlpool Corp	WHR	54.853	108.9	5,973.49		6.43%		-2.33%	
Williams Cos Inc/The	WMB	1216.499	36.79	44,755.00	0.15%	4.87%	0.01%	3.50%	0.01%
Constellation Energy Corp	CEG	319.382	121.04	38,658.00		0.93%		26.33%	
WEC Energy Group Inc	WEC	315.435	83.62	26,376.67	0.09%	3.73%	0.00%	6.41%	0.01%
Adobe Inc	ADBE	455.3	611.01	278,192.85	0.95%			17.33%	0.16%
AES Corp/The	AES	669.629	17.21	11,524.32	0.04%	3.86%	0.00%	10.12%	0.00%
Expeditors International of Washington Inc	EXPD	145.389	120.34	17,496.11		1.15%		-16.00%	
Amgen Inc	AMGN	535.178	269.64	144,305.40	0.49%	3.16%	0.02%	4.88%	0.02%
Apple Inc	AAPL	15552.752	189.95	2,954,245.24	10.06%	0.51%	0.05%	13.00%	1.31%
Autodesk Inc	ADSK	213.764	218.43	46,692.47	0.16%			12.48%	0.02%
Cintas Corp	CTAS	101.854	553.25	56,350.73	0.19%	0.98%	0.00%	11.84%	0.02%
Comcast Corp	CMCSA	4015.635	41.89	168,214.95	0.57%	2.77%	0.02%	9.26%	0.05%
Molson Coors Beverage Co	TAP	200.955	61.54	12,366.77	0.04%	2.66%	0.00%	12.99%	0.01%
KLA Corp	KLAC	135.932	544.62	74,031.29	0.25%	1.06%	0.00%	9.93%	0.03%
Marriott International Inc/MD	MAR	293.691	202.7	59,531.17	0.20%	1.03%	0.00%	17.38%	0.04%
Fiserv Inc	FI	600.186	130.61	78,390.29	0.27%			14.08%	0.04%
McCormick & Co Inc/MD	MKC	251.291	64.83	16,291.20	0.06%	2.59%	0.00%	7.01%	0.00%
PACCAR Inc	PCAR	523.076	91.82	48,028.84	0.16%	1.18%	0.00%	12.00%	0.02%
Costco Wholesale Corp	COST	442.741	592.74	262,430.30	0.89%	0.69%	0.01%	13.06%	0.12%
Stryker Corp	SYK	379.895	296.33	112,574.29	0.38%	1.01%	0.00%	7.62%	0.03%
Tyson Foods Inc	TSN	285.231	46.84	13,360.22		4.18%		46.71%	
Lamb Weston Holdings Inc	LW	144.927	100.03	14,497.05	0.05%	1.12%	0.00%	13.32%	0.01%
Applied Materials Inc	AMAT	836.534	149.78	125,296.06	0.43%	0.85%	0.00%	5.50%	0.02%
American Airlines Group Inc	AAL	653.541	12.43	8,123.51				54.64%	
Cardinal Health Inc	CAH	246.468	107.08	26,391.79	0.09%	1.87%	0.00%	13.32%	0.01%
Cincinnati Financial Corp	CINF	156.908	102.79	16,128.57	0.05%	2.92%	0.00%	18.21%	0.01%
Paramount Global	PARA	610.704	14.37	8,775.82		1.39%		-20.36%	
DR Horton Inc	DHI	333.184	127.67	42,537.60	0.14%	0.94%	0.00%	1.70%	0.00%
Electronic Arts Inc	EA	268.966	138.01	37,120.00	0.13%	0.55%	0.00%	10.32%	0.01%
Fair Isaac Corp	FICO	24.714	1087.6	26,878.95				22.00%	
Fastenal Co	FAST	571.413	59.97	34,267.64		2.33%			
M&T Bank Corp	MTB	165.96	128.17	21,271.09	0.07%	4.06%	0.00%	11.59%	0.01%
Xcel Energy Inc	XEL	551.816	60.84	33,572.49	0.11%	3.42%	0.00%	6.12%	0.01%
Fifth Third Bancorp	FITB	681.017	28.95	19,715.44		4.84%		25.00%	
Gilead Sciences Inc	GILD	1246.042	76.6	95,446.82	0.33%	3.92%	0.01%	2.10%	0.01%
Hasbro Inc	HAS	138.764	46.41	6,440.04		6.03%		-3.49%	
Huntington Bancshares Inc/OH	HBAN	1448.075	11.26	16,305.32		5.51%		-7.69%	
Welltower Inc	WELL	556.094	89.1	49,547.98	0.17%	2.74%	0.00%	10.96%	0.02%
Biogen Inc	BIIB	144.898	234.08	33,917.72	0.12%			0.87%	0.00%
Northern Trust Corp	NTRS	207.036	79.25	16,407.60	0.06%	3.79%	0.00%	5.93%	0.00%
Packaging Corp of America	PKG	89.624	168.01	15,057.73	0.05%	2.98%	0.00%	5.00%	0.00%

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] Bloomberg Long-Term Growth Est.	[11] Cap-Weighted Long-Term Growth Est.
Paychex Inc	PAYX	361.232	121.97	44,059.47	0.15%	2.92%	0.00%	7.00%	0.01%
QUALCOMM Inc	QCOM	1113	129.05	143,632.65	0.49%	2.48%	0.01%	11.61%	0.06%
Ross Stores Inc	ROST	338.632	130.38	44,150.84	0.15%	1.03%	0.00%	10.00%	0.02%
IDEXX Laboratories Inc	IDXX	83.052	465.82	38,687.28	0.13%			17.98%	0.02%
Starbucks Corp	SBUX	1136.7	99.3	112,874.31	0.38%	2.30%	0.01%	17.41%	0.07%
KeyCorp	KEY	936.26	12.39	11,600.26	0.04%	6.62%	0.00%	7.08%	0.00%
Fox Corp	FOXA	247.227	29.54	7,303.09	0.02%	1.76%	0.00%	6.24%	0.00%
Fox Corp	FOX	235.581	27.66	6,516.17	0.02%	1.88%	0.00%	6.24%	0.00%
State Street Corp	STT	308.584	72.82	22,471.09	0.08%	3.79%	0.00%	6.92%	0.01%
Norwegian Cruise Line Holdings Ltd	NCLH	425.425	15.27	6,496.24					
US Bancorp	USB	1557.012	38.12	59,353.30	0.20%	5.04%	0.01%	7.50%	0.02%
A O Smith Corp	AOS	122.828	75.36	9,256.32		1.70%			
Gen Digital Inc	GEN	640.715	22.08	14,146.99	0.05%	2.26%	0.00%	12.98%	0.01%
T Rowe Price Group Inc	TROW	223.47	100.13	22,376.05		4.87%		-4.09%	
Waste Management Inc	WM	402.775	170.99	68,870.50	0.23%	1.64%	0.00%	10.05%	0.02%
Constellation Brands Inc	STZ	183.663	240.49	44,169.11	0.15%	1.48%	0.00%	9.75%	0.01%
DENTSPLY SIRONA Inc	XRAY	211.86	31.75	6,726.56	0.02%	1.76%	0.00%	7.93%	0.00%
Zions Bancorp NA	ZION	148.149	35.63	5,278.55		4.60%		-9.73%	
Alaska Air Group Inc	ALK	128.053	37.81	4,841.68	0.02%			3.56%	0.00%
Invesco Ltd	IVZ	449.554	14.27	6,415.14		5.61%		-0.68%	
Intuit Inc	INTU	279.936	571.46	159,972.23	0.54%	0.63%	0.00%	18.96%	0.10%
Morgan Stanley	MS	1641.312	79.34	130,221.69	0.44%	4.29%	0.02%	3.64%	0.02%
Microchip Technology Inc	MCHP	541.045	83.44	45,144.79		2.10%		-1.00%	
Chubb Ltd	CB	407.99	229.43	93,605.15	0.32%	1.50%	0.00%	15.50%	0.05%
Hologic Inc	HOLX	240.003	71.3	17,112.21				-8.76%	
Citizens Financial Group Inc	CFG	466.223	27.27	12,713.90		6.16%		-10.63%	
O'Reilly Automotive Inc	ORLY	59.162	982.38	58,119.57	0.20%			11.39%	0.02%
Allstate Corp/The	ALL	261.687	137.87	36,078.79		2.58%		50.02%	
Equity Residential	EQR	379.724	56.84	21,583.51	0.07%	4.66%	0.00%	4.75%	0.00%
BorgWarner Inc	BWA	235.055	33.69	7,919.00	0.03%	1.31%	0.00%	4.33%	0.00%
Keurig Dr Pepper Inc	KDP	1398.336	31.57	44,145.47	0.15%	2.72%	0.00%	6.85%	0.01%
Host Hotels & Resorts Inc	HST	705.4	17.47	12,323.34		4.12%			
Incyte Corp	INCY	224.109	54.34	12,178.08				36.36%	
Simon Property Group Inc	SPG	326.247	124.89	40,744.99	0.14%	6.09%	0.01%	1.71%	0.00%
Eastman Chemical Co	EMN	118.564	83.83	9,939.22	0.03%	3.77%	0.00%	4.75%	0.00%
AvalonBay Communities Inc	AVB	142.015	172.94	24,560.07	0.08%	3.82%	0.00%	6.27%	0.01%
Prudential Financial Inc	PRU	361	97.78	35,298.58	0.12%	5.11%	0.01%	10.47%	0.01%
United Parcel Service Inc	UPS	723.257	151.61	109,652.99	0.37%	4.27%	0.02%	1.64%	0.01%
Walgreens Boots Alliance Inc	WBA	863.915	19.94	17,226.47	0.06%	9.63%	0.01%	0.25%	0.00%
STERIS PLC	STE	98.8	200.94	19,852.87		1.04%			
McKesson Corp	MCK	133.062	470.56	62,613.65	0.21%	0.53%	0.00%	10.04%	0.02%
Lockheed Martin Corp	LMT	248.099	447.77	111,091.29	0.38%	2.81%	0.01%	7.04%	0.03%
Cencora Inc	COR	199.433	203.37	40,558.69	0.14%	1.00%	0.00%	9.04%	0.01%
Capital One Financial Corp	COF	380.847	111.66	42,525.38		2.15%		-6.30%	
Waters Corp	WAT	59.127	280.61	16,591.63	0.06%			4.44%	0.00%
Nordson Corp	NDSN	57.014	235.34	13,417.67		1.16%			
Dollar Tree Inc	DLTR	217.872	123.59	26,926.80	0.09%			7.77%	0.01%
Darden Restaurants Inc	DRI	120.315	156.47	18,825.69	0.06%	3.35%	0.00%	10.45%	0.01%
Evergy Inc	EVRG	229.583	51.04	11,717.92	0.04%	5.04%	0.00%	4.82%	0.00%
Match Group Inc	MTCH	271.812	32.38	8,801.27				43.48%	
Domino's Pizza Inc	DPZ	34.881	392.89	13,704.40	0.05%	1.23%	0.00%	13.97%	0.01%
NVR Inc	NVR	3.179	6155.39	19,567.98				-4.57%	
NetApp Inc	NTAP	206.031	91.39	18,829.17	0.06%	2.19%	0.00%	7.40%	0.00%
Old Dominion Freight Line Inc	ODFL	109.114	389.06	42,451.89	0.14%	0.41%	0.00%	5.83%	0.01%
DaVita Inc	DVA	91.3	101.46	9,263.30				21.67%	
Hartford Financial Services Group Inc/The	HIG	300.77	78.16	23,508.18	0.08%	2.41%	0.00%	7.00%	0.01%
Iron Mountain Inc	IRM	291.99	64.15	18,731.16	0.06%	4.05%	0.00%	4.00%	0.00%
Estee Lauder Cos Inc/The	EL	232.305	127.69	29,663.03	0.10%	2.07%	0.00%	13.86%	0.01%
Cadence Design Systems Inc	CDNS	272.062	273.27	74,346.38	0.25%			18.56%	0.05%
Tyler Technologies Inc	TYL	42.124	408.84	17,221.98					
Universal Health Services Inc	UHS	61.007	137.48	8,387.24	0.03%	0.58%	0.00%	9.41%	0.00%
Skyworks Solutions Inc	SWKS	159.955	96.93	15,504.44		2.81%		-7.11%	
Quest Diagnostics Inc	DGX	112.435	137.23	15,429.46		2.07%		-1.27%	
Rockwell Automation Inc	ROK	114.673	275.44	31,585.53	0.11%	1.82%	0.00%	12.16%	0.01%
Kraft Heinz Co/The	KHC	1226.539	35.11	43,063.78	0.15%	4.56%	0.01%	4.03%	0.01%
American Tower Corp	AMT	466.165	208.78	97,325.93	0.33%	3.10%	0.01%	10.93%	0.04%
Regeneron Pharmaceuticals Inc	REGN	107.129	823.81	88,253.94	0.30%			4.00%	0.01%
Amazon.com Inc	AMZN	10334.031	146.09	1,509,698.59				86.99%	
Jack Henry & Associates Inc	JKHY	72.828	158.69	11,557.08	0.04%	1.31%	0.00%	7.06%	0.00%
Ralph Lauren Corp	RL	39.752	129.38	5,143.11	0.02%	2.32%	0.00%	10.38%	0.00%
Boston Properties Inc	BXP	156.939	56.93	8,934.54	0.03%	6.89%	0.00%	2.82%	0.00%
Amphenol Corp	APH	598.31	90.99	54,440.23	0.19%	0.97%	0.00%	4.04%	0.01%
Howmet Aerospace Inc	HWM	411.744	52.6	21,657.73		0.38%		20.41%	
Pioneer Natural Resources Co	PXD	233.309	231.64	54,043.70		5.53%		-3.00%	
Valero Energy Corp	VLO	340.453	125.36	42,679.19		3.25%		35.66%	
Synopsys Inc	SNPS	152.053	543.23	82,599.75	0.28%			16.68%	0.05%
Etsy Inc	ETSY	119.746	75.81	9,077.94	0.03%			2.74%	0.00%
CH Robinson Worldwide Inc	CHRW	116.651	82.05	9,571.21	0.03%	2.97%	0.00%	5.00%	0.00%
Accenture PLC	ACN	664.787	333.14	221,467.14	0.75%	1.55%	0.01%	10.00%	0.08%
TransDigm Group Inc	TDG	55.314	962.87	53,260.19	0.18%			15.56%	0.03%
Yum! Brands Inc	YUM	280.308	125.55	35,192.67	0.12%	1.93%	0.00%	11.93%	0.01%
Prologis Inc	PLD	923.862	114.93	106,179.46	0.36%	3.03%	0.01%	8.00%	0.03%
FirstEnergy Corp	FE	573.815	36.94	21,196.73		4.44%		-0.33%	
VeriSign Inc	VRSN	102.1	212.2	21,665.62	0.07%			11.50%	0.01%
Quanta Services Inc	PWR	145.285	188.31	27,358.62	0.09%	0.17%	0.00%	8.00%	0.01%
Henry Schein Inc	HSIC	130.585	66.73	8,713.94	0.03%			3.44%	0.00%
Ameren Corp	AEE	262.475	77.59	20,365.44	0.07%	3.25%	0.00%	7.11%	0.00%
ANSYS Inc	ANSS	86.873	293.36	25,485.06	0.09%			10.77%	0.01%
FactSet Research Systems Inc	FDS	37.988	453.46	17,226.04	0.06%	0.86%	0.00%	10.45%	0.01%
NVIDIA Corp	NVDA	2470	467.7	1,155,219.00		0.03%		50.82%	
Sealed Air Corp	SEE	144.436	33.38	4,821.27	0.02%	2.40%	0.00%	0.01%	0.00%
Cognizant Technology Solutions Corp	CTSH	501.413	70.38	35,289.45	0.12%	1.65%	0.00%	12.00%	0.01%
Intuitive Surgical Inc	ISRG	352.072	310.84	109,438.06	0.37%			11.57%	0.04%
Take-Two Interactive Software Inc	TTWO	170.068	158.2	26,904.76				58.00%	

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Republic Services Inc	RSG	314.637	161.84	50,920.85	0.17%	1.32%	0.00%	9.97%	0.02%
eBay Inc	EBAY	519	41.01	21,284.19	0.07%	2.44%	0.00%	0.32%	0.00%
Goldman Sachs Group Inc/The	GS	326.112	341.54	111,380.29	0.38%	3.22%	0.01%	7.71%	0.03%
SBA Communications Corp	SBAC	107.887	246.96	26,643.77	0.09%	1.38%	0.00%	8.00%	0.01%
Sempra	SRE	629.328	72.87	45,859.13	0.16%	3.27%	0.01%	5.49%	0.01%
Moody's Corp	MCO	183	364.96	66,787.68	0.23%	0.84%	0.00%	14.08%	0.03%
ON Semiconductor Corp	ON	430.698	71.33	30,721.69	0.10%			3.72%	0.00%
Booking Holdings Inc	BKNG	34.89	3125.7	109,055.67	0.37%			15.00%	0.06%
F5 Inc	FFIV	59.707	171.19	10,221.24	0.03%			5.45%	0.00%
Akamai Technologies Inc	AKAM	150.832	115.53	17,425.62					
Charles River Laboratories International Inc	CRL	51.297	197.08	10,109.61	0.03%			9.00%	0.00%
MarketAxess Holdings Inc	MKTX	37.905	240.12	9,101.75		1.20%			
Devon Energy Corp	DVN	640.7	44.97	28,812.28		6.85%		51.35%	
Bio-Techne Corp	TECH	158.15	62.9	9,947.64	0.03%	0.51%	0.00%	4.50%	0.00%
Alphabet Inc	GOOGL	5918	132.53	784,312.54	2.67%			16.65%	0.44%
Teleflex Inc	TFX	46.993	225.69	10,605.85	0.04%	0.60%	0.00%	7.00%	0.00%
Netflix Inc	NFLX	437.68	473.97	207,447.19				30.96%	
Allegion plc	ALLE	87.788	106.09	9,313.43	0.03%	1.70%	0.00%	5.93%	0.00%
Agilent Technologies Inc	A	292.123	127.8	37,333.32	0.13%	0.74%	0.00%	8.00%	0.01%
Warner Bros Discovery Inc	WBD	2438.566	10.45	25,483.01				91.04%	
Elevance Health Inc	ELV	234.959	479.49	112,660.49	0.38%	1.23%	0.00%	10.85%	0.04%
Trimble Inc	TRMB	248.768	46.4	11,542.84					
CME Group Inc	CME	359.99	218.36	78,607.42	0.27%	2.02%	0.01%	11.10%	0.03%
Juniper Networks Inc	JNPR	318.868	28.45	9,071.79	0.03%	3.09%	0.00%	7.96%	0.00%
BlackRock Inc	BLK	148.762	751.23	111,754.48	0.38%	2.66%	0.01%	6.72%	0.03%
DTE Energy Co	DTE	206.109	104.11	21,458.01	0.07%	3.66%	0.00%	7.00%	0.01%
Nasdaq Inc	NDAQ	576.965	55.84	32,217.73	0.11%	1.58%	0.00%	2.68%	0.00%
Celanese Corp	CE	108.855	138.66	15,093.83	0.05%	2.02%	0.00%	2.27%	0.00%
Philip Morris International Inc	PM	1552.406	93.36	144,932.62	0.49%	5.57%	0.03%	9.19%	0.05%
Salesforce Inc	CRM	968	251.9	243,839.20				21.67%	
Ingersoll Rand Inc	IR	404.797	71.43	28,914.65	0.10%	0.11%	0.00%	14.00%	0.01%
Huntington Ingalls Industries Inc	HII	39.723	237.02	9,415.15		2.19%		40.00%	
Roper Technologies Inc	ROP	106.822	538.25	57,496.94		0.56%		-1.00%	
MetLife Inc	MET	740.19	63.63	47,098.29	0.16%	3.27%	0.01%	9.17%	0.01%
Tapestry Inc	TPR	229.186	31.67	7,258.32	0.02%	4.42%	0.00%	11.00%	0.00%
CSX Corp	CSX	1976.131	32.3	63,829.03	0.22%	1.36%	0.00%	6.39%	0.01%
Edwards Lifesciences Corp	EW	606.5	67.71	41,066.12	0.14%			9.23%	0.01%
Ameriprise Financial Inc	AMP	101.196	353.51	35,773.80	0.12%	1.53%	0.00%	15.82%	0.02%
Zebra Technologies Corp	ZBRA	51.36	236.98	12,171.29					
Zimmer Biomet Holdings Inc	ZBH	208.981	116.31	24,306.58	0.08%	0.83%	0.00%	7.12%	0.01%
CBRE Group Inc	CBRE	304.793	78.96	24,066.46					
Camden Property Trust	CPT	106.771	90.26	9,637.15	0.03%	4.43%	0.00%	6.17%	0.00%
Mastercard Inc	MA	930.438	413.83	385,043.16	1.31%	0.55%	0.01%	17.35%	0.23%
CarMax Inc	KMX	158.668	63.94	10,145.23	0.03%			16.34%	0.01%
Intercontinental Exchange Inc	ICE	572.364	113.84	65,157.92	0.22%	1.48%	0.00%	8.66%	0.02%
Fidelity National Information Services Inc	FIS	592.484	58.64	34,743.26	0.12%	3.55%	0.00%	5.51%	0.01%
Chipotle Mexican Grill Inc	CMG	27.445	2202.25	60,440.75				25.41%	
Wynn Resorts Ltd	WYNN	112.946	84.42	9,534.90		1.18%		153.24%	
Live Nation Entertainment Inc	LYV	230.325	84.22	19,397.97					
Assurant Inc	AIZ	52.591	168.02	8,836.34	0.03%	1.71%	0.00%	14.60%	0.00%
NRG Energy Inc	NRG	225.764	47.84	10,800.55		3.16%			
Regions Financial Corp	RF	930.065	16.68	15,513.48	0.05%	5.76%	0.00%	0.99%	0.00%
Monster Beverage Corp	MNST	1040.441	55.15	57,380.32				21.32%	
Mosaic Co/The	MOS	326.835	35.89	11,730.11	0.04%	2.23%	0.00%	7.00%	0.00%
Baker Hughes Co	BKR	1006.234	33.75	33,960.40	0.12%	2.37%	0.00%	16.00%	0.02%
Expedia Group Inc	EXPE	133.325	136.18	18,156.20	0.06%			17.50%	0.01%
CF Industries Holdings Inc	CF	191.057	75.15	14,357.93		2.13%		46.00%	
Leidos Holdings Inc	LDOS	137.506	107.32	14,757.14	0.05%	1.42%	0.00%	8.12%	0.00%
APA Corp	APA	306.719	36	11,041.88	0.04%	2.78%	0.00%	0.72%	0.00%
Alphabet Inc	GOOG	5725	133.92	766,692.00	2.61%			16.65%	0.43%
First Solar Inc	FSLR	106.844	157.78	16,857.85				43.22%	
TE Connectivity Ltd	TEL	310.779	131	40,712.05		1.80%			
Discover Financial Services	DFS	250.058	93	23,255.39		3.01%		56.16%	
Visa Inc	V	1580.68	256.68	405,728.94	1.38%	0.81%	0.01%	14.32%	0.20%
Mid-America Apartment Communities Inc	MAA	116.688	124.48	14,525.32	0.05%	4.50%	0.00%	1.77%	0.00%
Xylem Inc/NY	XYL	241.078	105.13	25,344.53		1.26%			
Marathon Petroleum Corp	MPC	379.697	149.19	56,647.00		2.21%			
Advanced Micro Devices Inc	AMD	1615.499	121.16	195,733.86				30.65%	
Tractor Supply Co	TSCO	108.114	203.01	21,948.22	0.07%	2.03%	0.00%	3.81%	0.00%
ResMed Inc	RMD	147.092	157.73	23,200.82		1.22%			
Mettler-Toledo International Inc	MTD	21.684	1091.93	23,677.41	0.08%			5.01%	0.00%
Jacobs Solutions Inc	J	126.024	127.18	16,027.73	0.05%	0.82%	0.00%	12.31%	0.01%
Copart Inc	CPRT	960.231	50.22	48,222.80					
VICI Properties Inc	VICI	1034.532	29.89	30,922.16	0.11%	5.55%	0.01%	7.09%	0.01%
Fortinet Inc	FTNT	767.91	52.56	40,361.35	0.14%			15.03%	0.02%
Albemarle Corp	ALB	117.353	121.27	14,231.40	0.05%	1.32%	0.00%	18.79%	0.01%
Moderna Inc	MRNA	381.284	77.7	29,625.77				-29.33%	
Essex Property Trust Inc	ESS	64.183	213.46	13,700.50	0.05%	4.33%	0.00%	5.71%	0.00%
CoStar Group Inc	CSGP	408.363	83.04	33,910.46	0.12%			20.00%	0.02%
Realty Income Corp	O	723.924	53.96	39,062.94	0.13%	5.69%	0.01%	0.68%	0.00%
Westrock Co	WRK	256.469	41.17	10,558.83	0.04%	2.94%	0.00%	4.20%	0.00%
Westinghouse Air Brake Technologies Corp	WAB	179.159	116.56	20,882.77	0.07%	0.58%	0.00%	12.86%	0.01%
Pool Corp	POOL	38.679	347.32	13,433.99		1.27%		-5.49%	
Western Digital Corp	WDC	324.243	48.31	15,664.18				-11.96%	
PepsiCo Inc	PEP	1374.864	168.29	231,375.86	0.79%	3.01%	0.02%	8.70%	0.07%
Diamondback Energy Inc	FANG	178.985	154.41	27,637.07		8.73%		21.94%	
Palo Alto Networks Inc	PANW	315.3	295.09	93,041.88				30.00%	
ServiceNow Inc	NOW	205	685.74	140,576.70					
Church & Dwight Co Inc	CHD	246.382	96.63	23,807.89	0.08%	1.13%	0.00%	5.95%	0.00%
Federal Realty Investment Trust	FRT	81.618	95.59	7,801.86	0.03%	4.56%	0.00%	5.77%	0.00%
MGM Resorts International	MGM	341.583	39.44	13,472.03					
American Electric Power Co Inc	AEP	515.176	79.55	40,982.25	0.14%	4.42%	0.01%	4.83%	0.01%
SolarEdge Technologies Inc	SEDG	56.811	79.38	4,509.66				27.00%	
Invitation Homes Inc	INVH	611.958	33.36	20,414.92	0.07%	3.12%	0.00%	3.15%	0.00%

		[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	Bloomberg Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
PTC Inc	PTC	119.245	157.36	18,764.39	0.06%			19.31%	0.01%
JB Hunt Transport Services Inc	JBHT	103.143	185.27	19,109.30		0.91%		27.00%	
Lam Research Corp	LRCX	131.792	715.92	94,352.53	0.32%	1.12%	0.00%	5.44%	0.02%
Mohawk Industries Inc	MHK	63.682	88.31	5,623.76				-3.08%	
Pentair PLC	PNR	165.299	64.54	10,668.40	0.04%	1.36%	0.00%	6.22%	0.00%
GE HealthCare Technologies Inc	GEHC	455.243	68.46	31,165.94	0.11%	0.18%	0.00%	12.70%	0.01%
Vertex Pharmaceuticals Inc	VRTX	257.683	354.81	91,428.51	0.31%			13.38%	0.04%
Amcor PLC	AMCR	1445.343	9.48	13,701.85	0.05%	5.27%	0.00%	1.33%	0.00%
Meta Platforms Inc	META	2219.607	327.15	726,144.43				24.05%	
T-Mobile US Inc	TMUS	1156.475	150.45	173,991.66		1.73%		38.46%	
United Rentals Inc	URI	67.781	476.02	32,265.11	0.11%	1.24%	0.00%	17.87%	0.02%
Honeywell International Inc	HON	659.251	195.92	129,160.46	0.44%	2.20%	0.01%	7.69%	0.03%
Alexandria Real Estate Equities Inc	ARE	173.775	109.4	19,010.99	0.06%	4.53%	0.00%	5.28%	0.00%
Delta Air Lines Inc	DAL	643.463	36.93	23,763.09		1.08%		30.85%	
Seagate Technology Holdings PLC	STX	209.184	79.1	16,546.45	0.06%	3.54%	0.00%	6.11%	0.00%
United Airlines Holdings Inc	UAL	328.017	39.4	12,923.87				46.54%	
News Corp	NWS	191.385	23.04	4,409.51		0.87%			
Centene Corp	CNC	534.201	73.68	39,359.93	0.13%			8.43%	0.01%
Martin Marietta Materials Inc	MLM	61.807	464.59	28,714.91		0.64%		21.60%	
Teradyne Inc	TER	152.879	92.23	14,100.03	0.05%	0.48%	0.00%	7.82%	0.00%
PayPal Holdings Inc	PYPL	1078.14	57.61	62,111.65	0.21%			6.26%	0.01%
Tesla Inc	TSLA	3178.921	240.08	763,195.35	2.60%			11.00%	0.29%
Arch Capital Group Ltd	ACGL	373.172	83.69	31,230.76	0.11%			10.00%	0.01%
Dow Inc	DOW	701.397	51.75	36,297.29		5.41%		-4.72%	
Everest Group Ltd	EG	43.39	410.55	17,813.76		1.71%		37.66%	
Teledyne Technologies Inc	TDY	47.185	402.96	19,013.67	0.06%			8.03%	0.01%
News Corp	NWSA	380.67	22.04	8,389.97		0.91%			
Exelon Corp	EXC	994.299	38.51	38,290.45	0.13%	3.74%	0.00%	4.00%	0.01%
Global Payments Inc	GPN	260.389	116.44	30,319.70	0.10%	0.86%	0.00%	13.33%	0.01%
Crown Castle Inc	CCI	433.689	117.28	50,863.05	0.17%	5.34%	0.01%	7.00%	0.01%
Aptiv PLC	APTV	282.862	82.84	23,432.29	0.08%			11.44%	0.01%
Align Technology Inc	ALGN	76.589	213.8	16,374.73					
Illumina Inc	ILMN	158.8	101.95	16,189.66				-51.00%	
Kenvue Inc	KVUE	1914.995	20.44	39,142.50		3.91%			
Targa Resources Corp	TRGP	222.976	90.45	20,168.18	0.07%	2.21%	0.00%	15.00%	0.01%
Bunge Global SA	BG	161.429	109.87	17,736.20		2.41%		-5.00%	
LKQ Corp	LKQ	267.598	44.53	11,916.14		2.69%			
Zoetis Inc	ZTS	459.114	176.67	81,111.67	0.28%	0.85%	0.00%	10.91%	0.03%
Digital Realty Trust Inc	DLR	302.846	138.78	42,028.97	0.14%	3.52%	0.01%	6.80%	0.01%
Equinix Inc	EQIX	93.883	815.01	76,515.58	0.26%	2.09%	0.01%	16.67%	0.04%
Las Vegas Sands Corp	LVS	764.491	46.12	35,258.32		1.73%			
Molina Healthcare Inc	MOH	58.3	365.56	21,312.15	0.07%			11.24%	0.01%

Notes:
[1] Equals sum of Col. [9]
[2] Equals sum of Col. [11]
[3] Equals ([1] x (1 + (0.5 x [2]))) + [2]
[4] Bloomberg Professional as of November 30, 2023
[5] Bloomberg Professional as of November 30, 2023
[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 November 30, 2023
[9] Equals [7] x [8]
[10] Value Line, as of November 30, 2023
[11] Equals [7] x [10]

Docket No. UE 433
Exhibit PAC/410
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

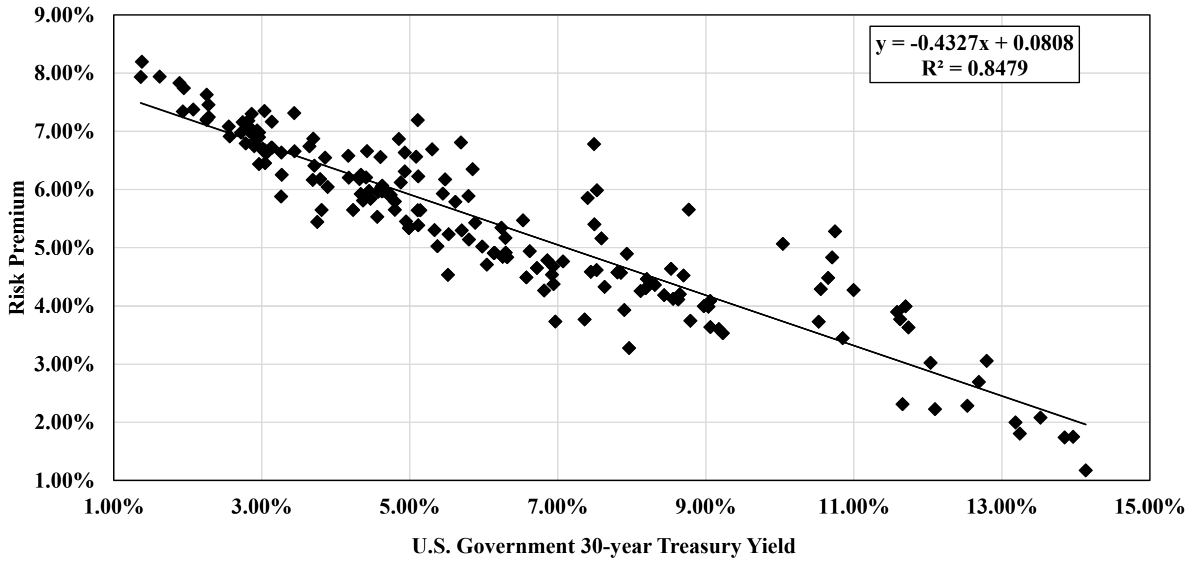
OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Ann E. Bulkley

Risk Premium Approach

February 2024



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.9205958
R Square	0.8474967
Adjusted R Square	0.8466202
Standard Error	0.0056565
Observations	176

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.03094	0.03094	966.95886	0.00000
Residual	174	0.00557	0.00003		
Total	175	0.03651			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.0808	0.00	85.17	0.0000	0.0789	0.0827	0.0789	0.0827
U.S. Govt. 30-year Treasury	(0.4330)	0.01	(31.10)	0.0000	(0.4605)	(0.4056)	(0.4605)	(0.4056)

	[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]	4.77%	6.01%	10.79%
Blue Chip Near-Term Projected Forecast (Q1 2024 - Q1 2025) [5]	4.48%	6.14%	10.62%
Blue Chip Long-Term Projected Forecast (2025-2029) [6]	4.10%	6.30%	10.40%
AVERAGE			10.60%

Notes:
[1] Regulatory Research Associates, rate cases through November 30, 2023
[2] S&P Capital IQ Pro, quarterly bond yields are the average of each trading day in the quarter
[3] Equals Column [1] − Column [2]
[4] S&P Capital IQ Pro, 30-day average as of November 30, 2023
[5] Blue Chip Financial Forecasts, Vol. 42, No. 12, December 1, 2023, at 2
[6] Blue Chip Financial Forecasts, Vol. 42, No. 12, December 1, 2023, at 14.
[7] See notes [4], [5] & [6]
[8] Equals 0.079161 + (-0.431626 x Column [7])
[9] Equals Column [7] + Column [8]

BOND YIELD PLUS RISK PREMIUM

Quarter	[1] Average Authorized VI Electric ROE	[2] U.S. Govt. 30-year Treasury	[3] Risk Premium
1980.1	13.97%	11.66%	2.31%
1980.2	14.25%	10.52%	3.73%
1980.3	14.30%	10.85%	3.45%
1980.4	14.32%	12.10%	2.23%
1981.1	14.82%	12.53%	2.28%
1981.2	15.05%	13.24%	1.81%
1981.3	15.31%	14.13%	1.17%
1981.4	15.59%	13.85%	1.74%
1982.1	15.71%	13.96%	1.75%
1982.2	15.60%	13.52%	2.08%
1982.3	15.85%	12.79%	3.06%
1982.4	16.03%	10.75%	5.28%
1983.1	15.54%	10.71%	4.83%
1983.2	15.13%	10.65%	4.48%
1983.3	15.39%	11.62%	3.77%
1983.4	15.37%	11.74%	3.63%
1984.1	15.06%	12.04%	3.02%
1984.2	15.18%	13.18%	2.00%
1984.3	15.38%	12.69%	2.69%
1984.4	15.69%	11.70%	3.99%
1985.1	15.48%	11.58%	3.90%
1985.2	15.27%	11.00%	4.27%
1985.3	14.84%	10.55%	4.29%
1985.4	15.11%	10.04%	5.07%
1986.1	14.42%	8.77%	5.65%
1986.2	14.27%	7.49%	6.78%
1986.3	13.26%	7.40%	5.86%
1986.4	13.52%	7.53%	5.99%
1987.1	12.90%	7.49%	5.40%
1987.2	13.17%	8.53%	4.64%
1987.3	13.14%	9.06%	4.08%
1987.4	12.76%	9.23%	3.53%
1988.1	12.74%	8.63%	4.11%
1988.2	12.70%	9.06%	3.63%
1988.3	12.78%	9.18%	3.60%
1988.4	12.97%	8.97%	4.00%
1989.1	13.02%	9.04%	3.99%
1989.2	13.22%	8.70%	4.52%
1989.3	12.38%	8.12%	4.26%
1989.4	12.83%	7.93%	4.90%
1990.1	12.62%	8.44%	4.19%
1990.2	12.85%	8.65%	4.20%
1990.3	12.54%	8.79%	3.75%
1990.4	12.68%	8.56%	4.12%
1991.1	12.66%	8.20%	4.46%
1991.2	12.67%	8.31%	4.36%
1991.3	12.49%	8.19%	4.30%
1991.4	12.42%	7.85%	4.57%
1992.1	12.38%	7.81%	4.58%
1992.2	11.83%	7.90%	3.93%
1992.3	12.03%	7.45%	4.59%
1992.4	12.14%	7.52%	4.62%
1993.1	11.84%	7.07%	4.76%
1993.2	11.64%	6.86%	4.78%
1993.3	11.15%	6.32%	4.84%
1993.4	11.04%	6.14%	4.91%
1994.1	11.07%	6.58%	4.49%
1994.2	11.13%	7.36%	3.77%
1994.3	12.75%	7.59%	5.16%
1994.4	11.24%	7.96%	3.28%
1995.1	11.96%	7.63%	4.33%
1995.2	11.32%	6.94%	4.37%
1995.3	11.37%	6.72%	4.65%

1995.4	11.58%	6.24%	5.35%
1996.1	11.46%	6.29%	5.17%
1996.2	11.46%	6.92%	4.54%
1996.3	10.70%	6.97%	3.73%
1996.4	11.56%	6.62%	4.94%
1997.1	11.08%	6.82%	4.26%
1997.2	11.62%	6.94%	4.68%
1997.3	12.00%	6.53%	5.47%
1997.4	11.06%	6.15%	4.91%
1998.1	11.31%	5.88%	5.43%
1998.2	12.20%	5.85%	6.35%
1998.3	11.65%	5.48%	6.17%
1998.4	12.30%	5.11%	7.19%
1999.1	10.40%	5.37%	5.03%
1999.2	10.94%	5.80%	5.14%
1999.3	10.75%	6.04%	4.71%
1999.4	11.10%	6.26%	4.84%
2000.1	11.21%	6.30%	4.92%
2000.2	11.00%	5.98%	5.02%
2000.3	11.68%	5.79%	5.89%
2000.4	12.50%	5.69%	6.81%
2001.1	11.38%	5.45%	5.93%
2001.2	11.00%	5.70%	5.30%
2001.3	10.76%	5.53%	5.23%
2001.4	11.99%	5.30%	6.69%
2002.1	10.05%	5.52%	4.53%
2002.2	11.41%	5.62%	5.79%
2002.3	11.65%	5.09%	6.56%
2002.4	11.57%	4.93%	6.63%
2003.1	11.72%	4.85%	6.87%
2003.2	11.16%	4.60%	6.56%
2003.3	10.50%	5.11%	5.39%
2003.4	11.34%	5.11%	6.23%
2004.1	11.00%	4.88%	6.12%
2004.2	10.64%	5.34%	5.30%
2004.3	10.75%	5.11%	5.64%
2004.4	11.24%	4.93%	6.31%
2005.1	10.63%	4.71%	5.92%
2005.2	10.31%	4.47%	5.84%
2005.3	11.08%	4.42%	6.66%
2005.4	10.63%	4.65%	5.98%
2006.1	10.70%	4.63%	6.07%
2006.2	10.79%	5.14%	5.64%
2006.3	10.35%	5.00%	5.35%
2006.4	10.65%	4.74%	5.91%
2007.1	10.59%	4.80%	5.79%
2007.2	10.33%	4.99%	5.34%
2007.3	10.40%	4.95%	5.45%
2007.4	10.65%	4.61%	6.04%
2008.1	10.62%	4.41%	6.21%
2008.2	10.54%	4.57%	5.96%
2008.3	10.43%	4.45%	5.98%
2008.4	10.39%	3.64%	6.74%
2009.1	10.75%	3.44%	7.31%
2009.2	10.75%	4.17%	6.58%
2009.3	10.50%	4.32%	6.18%
2009.4	10.59%	4.34%	6.25%
2010.1	10.59%	4.62%	5.97%
2010.2	10.18%	4.37%	5.81%
2010.3	10.40%	3.86%	6.55%
2010.4	10.38%	4.17%	6.20%
2011.1	10.09%	4.56%	5.53%
2011.2	10.26%	4.34%	5.92%
2011.3	10.57%	3.70%	6.88%
2011.4	10.39%	3.04%	7.35%
2012.1	10.30%	3.14%	7.17%
2012.2	9.95%	2.94%	7.01%
2012.3	9.90%	2.74%	7.16%

2012.4	10.16%	2.86%	7.30%
2013.1	9.85%	3.13%	6.72%
2013.2	9.86%	3.14%	6.72%
2013.3	10.12%	3.71%	6.41%
2013.4	9.97%	3.79%	6.18%
2014.1	9.86%	3.69%	6.16%
2014.2	10.10%	3.44%	6.66%
2014.3	9.90%	3.27%	6.63%
2014.4	9.94%	2.96%	6.98%
2015.1	9.64%	2.55%	7.08%
2015.2	9.83%	2.88%	6.94%
2015.3	9.40%	2.96%	6.44%
2015.4	9.86%	2.96%	6.90%
2016.1	9.70%	2.72%	6.98%
2016.2	9.48%	2.57%	6.91%
2016.3	9.74%	2.28%	7.46%
2016.4	9.83%	2.83%	7.00%
2017.1	9.72%	3.05%	6.67%
2017.2	9.64%	2.90%	6.75%
2017.3	10.00%	2.82%	7.18%
2017.4	9.91%	2.82%	7.09%
2018.1	9.69%	3.02%	6.66%
2018.2	9.75%	3.09%	6.66%
2018.3	9.69%	3.06%	6.63%
2018.4	9.52%	3.27%	6.25%
2019.1	9.72%	3.01%	6.70%
2019.2	9.58%	2.78%	6.79%
2019.3	9.53%	2.29%	7.25%
2019.4	9.89%	2.26%	7.63%
2020.1	9.72%	1.89%	7.83%
2020.2	9.58%	1.38%	8.19%
2020.3	9.30%	1.37%	7.93%
2020.4	9.56%	1.62%	7.94%
2021.1	9.45%	2.07%	7.38%
2021.2	9.47%	2.26%	7.21%
2021.3	9.27%	1.93%	7.34%
2021.4	9.69%	1.95%	7.74%
2022.1	9.45%	2.25%	7.20%
2022.2	9.50%	3.05%	6.45%
2022.3	9.14%	3.26%	5.88%
2022.4	9.94%	3.89%	6.04%
2023.1	9.72%	3.75%	5.44%
2023.2	9.67%	3.81%	5.65%

Docket No. UE 433
Exhibit PAC/411
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Ann E. Bulkley

Wildfire Risk Analysis

February 2024

COMPARISON OF OG&E AND PROXY GROUP COMPANIES
WILDFIRE EXPECTED ANNUAL LOSS RANKINGS

		[1]	[2]
		RRA	
	Operation State	Rank	Numeric Rank
ALLETE, Inc.	Minnesota	Relatively Low	2
Alliant Energy Corporation	Iowa	Very Low	1
	Wisconsin	Very Low	1
Ameren Corporation	Illinois	Very Low	1
	Missouri	Relatively Low	2
American Electric Power Company, Inc	Arkansas	Relatively Low	2
	Indiana	Very Low	1
	Kentucky	Relatively Low	2
	Louisiana	Relatively Low	2
	Michigan	Very Low	1
	Ohio	Very Low	1
	Oklahoma	Relatively Moderate	3
	Tennessee	Very Low	1
	Texas	Relatively High	4
	Virginia	Relatively Low	2
	West Virginia	Very Low	1
Avista Corporation	Alaska	Relatively Low	2
	Idaho	Relatively Moderate	3
	Oregon	Relatively Moderate	3
	Washington	Relatively Moderate	3
CMS Energy Corporation	Michigan	Very Low	1
Duke Energy Corporation	Florida	Relatively High	4
	Indiana	Very Low	1
	Kentucky	Relatively Low	2
	North Carolina	Relatively Low	2
	Ohio	Very Low	1
	South Carolina	Relatively Low	2
	Tennessee	Very Low	1
Entergy Corporation	Arkansas	Relatively Low	2
	Louisiana	Relatively Low	2
	Louisiana	Relatively Low	2
	Mississippi	Relatively Low	2
	Texas	Relatively High	4
Evergy, Inc.	Kansas	Relatively Low	2
	Missouri	Relatively Low	2
IDACORP, Inc.	Idaho	Relatively Moderate	3
	Oregon	Relatively Moderate	3
NextEra Energy, Inc.	Florida	Relatively High	4
	Texas	Relatively High	4
NorthWestern Corporation	Montana	Relatively Moderate	3
	Nebraska	Very Low	1
	South Dakota	Relatively Low	2
OGE Energy Corporation	Arkansas	Relatively Low	2
	Oklahoma	Relatively Moderate	3
Pinnacle West Capital Corporation	Arizona	Relatively High	4
Portland General Electric Company	Oregon	Relatively Moderate	3
Southern Company	Alabama	Very Low	1
	Georgia	Relatively Low	2
	Illinois	Very Low	1
	Mississippi	Relatively Low	2
	Tennessee	Very Low	1
	Virginia	Relatively Low	2
Xcel Energy Inc.	Colorado	Relatively Moderate	3
	Minnesota	Relatively Low	2
	New Mexico	Relatively Moderate	3
	North Dakota	Relatively Low	2
	South Dakota	Relatively Low	2
	Texas	Relatively High	4
	Wisconsin	Very Low	1
Proxy Group Average		Relatively Low	2.14
PacifiCorp	Oregon	Relatively Moderate	3

Notes
[1] FEMA National Risk Index, States and Territories - Expected Annual Loss (Table);
https://hazards.fema.gov/nri/data-resources#csvDownload
[2] Very Low = 1, Relatively Low = 2, Relatively Moderate = 3, Relatively High = 4, Very High = 5

Docket No. UE 433
Exhibit PAC/412
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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Ann E. Bulkley

Capital Expenditures Analysis

February 2024

PROJECTED CAPITAL EXPENDITURES AS A PERCENT OF 2022 NET PLANT

($ Millions)

		[1]	[2]	[3]	[4]	[5]	
		2022	2024	2025	2026	Projected Cap. Ex. / 2022 Net Plant	Rank
ALLETE, Inc.	ALE						
Capital Spending per Share			$5.95	$6.60	$7.25		
Common Shares Outstanding			59.00	60.00	61.00		
Capital Expenditures			$351.1	$396.0	$442.3	23.8%	1
Net Plant		$5,004.0					
Alliant Energy Corporation	LNT						
Capital Spending per Share			$5.80	$5.60	$5.40		
Common Shares Outstanding			256.00	256.50	257.00		
Capital Expenditures			$1,484.8	$1,436.4	$1,387.8	26.5%	4
Net Plant		$16,247.0					
Ameren Corporation	AEE						
Capital Spending per Share			$12.55	$12.78	$13.00		
Common Shares Outstanding			269.00	277.00	285.00		
Capital Expenditures			$3,376.0	$3,538.7	$3,705.0	34.0%	12
Net Plant		$31,262.0					
American Electric Power Company	AEP						
Capital Spending per Share			$14.15	$14.08	$14.00		
Common Shares Outstanding			530.00	540.00	550.00		
Capital Expenditures			$7,499.5	$7,600.5	$7,700.0	32.0%	10
Net Plant		$71,283.0					
Avista Corporation	AVA						
Capital Spending per Share			$6.35	$6.55	$6.75		
Common Shares Outstanding			78.50	81.75	85.00		
Capital Expenditures			$498.5	$535.5	$573.8	29.5%	7
Net Plant		$5,444.7					
CMS Energy Corporation	CMS						
Capital Spending per Share			$9.50	$9.63	$9.75		
Common Shares Outstanding			295.00	297.50	300.00		
Capital Expenditures			$2,802.5	$2,863.4	$2,925.0	37.8%	14
Net Plant		$22,713.0					
Duke Energy Corporation	DUK						
Capital Spending per Share			$17.60	$17.18	$16.75		
Common Shares Outstanding			770.00	770.00	770.00		
Capital Expenditures			$13,552.0	$13,224.8	$12,897.5	35.5%	13
Net Plant		$111,748.0					
Entergy Corporation	ETR						
Capital Spending per Share			$19.00	$19.38	$19.75		
Common Shares Outstanding			$218.00	224.00	230.00		
Capital Expenditures			$4,142.0	$4,340.0	$4,542.5	30.7%	8
Net Plant		$42,477.0					
Evergy, Inc.	EVRG						
Capital Spending per Share			$9.25	$9.38	$9.50		
Common Shares Outstanding			230.00	230.00	230.00		
Capital Expenditures			$2,127.5	$2,156.3	$2,185.0	29.2%	6
Net Plant		$22,137.0					
IDACORP, Inc.	IDA						
Capital Spending per Share			$16.00	$13.50	$11.00		
Common Shares Outstanding			51.50	52.25	53.00		
Capital Expenditures			$824.0	$705.4	$583.0	40.8%	16
Net Plant		$5,173.0					

PROJECTED CAPITAL EXPENDITURES AS A PERCENT OF 2022 NET PLANT

($ Millions)

		[1]	[2]	[3]	[4]	[5]	
		2022	2024	2025	2026	Projected Cap. Ex. / 2022 Net Plant	Rank
NextEra Energy, Inc.	NEE						
Capital Spending per Share			$9.50	$9.63	$9.75		
Common Shares Outstanding			2025.00	2037.50	2050.00		
Capital Expenditures			$19,237.5	$19,610.9	$19,987.5	53.0%	18
Net Plant		$111,059.0					
NorthWestern Corporation	NWE						
Capital Spending per Share			$7.75	$7.38	$7.00		
Common Shares Outstanding			62.00	62.00	62.00		
Capital Expenditures			$480.5	$457.3	$434.0	24.2%	2
Net Plant		$5,657.5					
OGE Energy Corporation	OGE						
Capital Spending per Share			$4.75	$4.75	$4.75		
Common Shares Outstanding			200.20	200.20	200.20		
Capital Expenditures			$951.0	$951.0	$951.0	27.0%	5
Net Plant		$10,546.8					
Pinnacle West Capital Corporation	PNW						
Capital Spending per Share			$15.00	$15.00	$15.00		
Common Shares Outstanding			$118.00	119.00	120.00		
Capital Expenditures			$1,770.0	$1,785.0	$1,800.0	31.8%	9
Net Plant		$16,854.0					
Portland General Electric Company	POR						
Capital Spending per Share			$10.75	$10.88	$11.00		
Common Shares Outstanding			102.00	102.00	102.00		
Capital Expenditures			$1,096.5	$1,109.3	$1,122.0	39.3%	15
Net Plant		$8,465.0					
Southern Company	SO						
Capital Spending per Share			$7.85	$7.68	$7.50		
Common Shares Outstanding			1,070.00	1,070.00	1,070.00		
Capital Expenditures			$8,399.5	$8,212.3	$8,025.0	26.1%	3
Net Plant		$94,570.0					
Xcel Energy Inc.	XEL						
Capital Spending per Share			$9.25	$9.38	$9.50		
Common Shares Outstanding			553.00	556.50	560.00		
Capital Expenditures			$5,115.3	$5,217.2	$5,320.0	32.4%	11
Net Plant		$48,253.0					
PacifiCorp	PacificCorp						
Capital Expenditures [7]				$10,600.00		43.4%	17
Net Plant [8]		$24,400.0					

Notes:

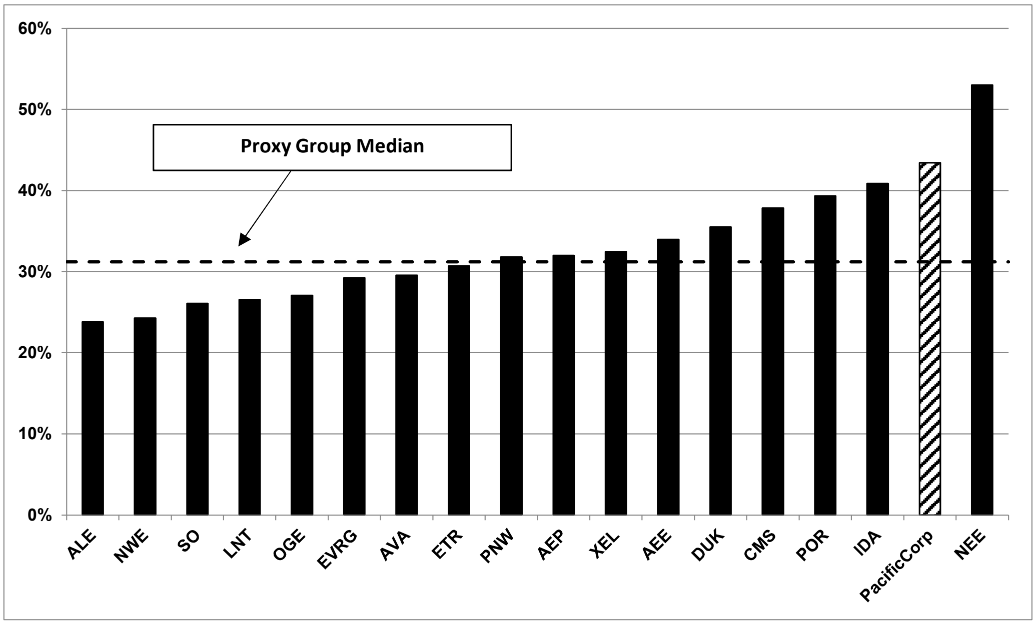
[1] - [5] Value Line, dated September 8, October 20, November 10, 2023.

[6] Equals (Column [2] + [3] + [4] + [5]) / Column [1]

[7] Company Provided Data

[8] Company Provided Data

PROJECTED CAPITAL EXPENDITURES AS A PERCENT OF 2022 NET PLANT



Projected CAPEX / 2022 Net Plant

Rank	Company		Percent
1	ALLETE, Inc.	ALE	23.8%
2	NorthWestern Corporation	NWE	24.2%
3	Southern Company	SO	26.1%
4	Alliant Energy Corporation	LNT	26.5%
5	OGE Energy Corporation	OGE	27.0%
6	Evergy, Inc.	EVRG	29.2%
7	Avista Corporation	AVA	29.5%
8	Entergy Corporation	ETR	30.7%
9	Pinnacle West Capital Corporation	PNW	31.8%
10	American Electric Power Company	AEP	32.0%
11	Xcel Energy Inc.	XEL	32.4%
12	Ameren Corporation	AEE	34.0%
13	Duke Energy Corporation	DUK	35.5%
14	CMS Energy Corporation	CMS	37.8%
15	Portland General Electric Company	POR	39.3%
16	IDACORP, Inc.	IDA	40.8%
17	PacifiCorp	PacificCorp	43.4%
18	NextEra Energy, Inc.	NEE	53.0%
	Proxy Group Median		31.2%
	Pacificorp as % of Median		139.2%

Notes:
PAC/412, pp. 1-2 col. [6]

Docket No. UE 433
Exhibit PAC/413
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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Ann E. Bulkley

Regulatory Risk Analysis

February 2024

COMPARISON OF OG&E AND PROXY GROUP COMPANIES
RISK ASSESSMENT

				[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
					Decoupling / Revenue Stabilization				Capital Cost Recovery					
Proxy Group Company	**Operating Subsidiary**	**Jurisdiction**	**Service**	**Test Year**	**Revenue Decoupling**	**Formula-Based Rates**	**Straight Fixed-Variable**	**Total**	**Traditional Generation**	**Renewables/Non-Traditional Generation**	**Delivery Infrastructure**	**Environmental Compliance**	**Total**	**Fuel Adjustment Clause**
ALLETE, Inc.	ALLETE (Minnesota Power)	Minnesota	Electric	Fully Forecast	No	No	No	No	No	Yes	No	No	Yes	Yes
Alliant Energy Corporation	Interstate Power & Light Co.	Iowa	Electric	Historical	No	No	No	No	No	Yes	No	Yes	Yes	Yes
	Interstate Power & Light Co.	Iowa	Gas	Historical	No	No	No	No	No	No	No	No	No	Yes
	Wisconsin Power & Light Co.	Wisconsin	Electric	Fully Forecast	No	No	No	No	No	No	No	No	No	Yes
	Wisconsin Power & Light Co.	Wisconsin	Gas	Fully Forecast	No	No	No	No	No	No	No	No	No	Yes
Ameren Corporation	Ameren Illinois Co.	Illinois	Electric	Historical	Partial	Yes	No	Yes	No	Yes	No	Yes	Yes	n/a
	Ameren Illinois Co.	Illinois	Gas	Fully Forecast	Partial	No	No	Yes	No	No	Yes	Yes	Yes	Yes
	Union Electric Co.	Missouri	Electric	Historical	Partial	No	No	Yes	No	Yes	Yes	No	Yes	Yes
	Union Electric Co.	Missouri	Gas	Historical	Partial	No	No	Yes	No	No	Yes	No	Yes	Yes
American Electric Power Compan	Southwestern Electric Power Co.	Arkansas	Electric	Historical	Partial	Yes	No	Yes	Yes	No	No	Yes	Yes	Yes
	Indiana Michigan Power Co.	Indiana	Electric	Fully Forecast	Full	No	No	Yes	No	Yes	Yes	Yes	Yes	Yes
	Kentucky Power Co.	Kentucky	Electric	Fully Forecast	Partial	No	No	Yes	No	No	Yes	No	Yes	Yes
	Southwestern Electric Power Co.	Louisiana	Electric	Historical	Partial	Yes	No	Yes	No	No	No	No	No	Yes
	Indiana Michigan Power Co.	Michigan	Electric	Fully Forecast	Partial	No	No	Yes	No	Yes	No	No	Yes	Yes
	Ohio Power Co.	Ohio	Electric	Partially Forecast	Partial	No	No	Yes	No	Yes	Yes	No	Yes	Yes
	Public Service Co. of Oklahoma	Oklahoma	Electric	Historical	Partial	No	No	Yes	No	Yes	Yes	No	Yes	Yes
	Kingsport Power Co.	Tennessee	Electric	Fully Forecast	No	No	No	No	No	No	No	No	No	Yes
	AEP Texas Inc.	Texas	Electric	Historical	No	No	No	No	No	No	Yes	No	Yes	n/a
	Southwestern Electric Power Co.	Texas	Electric	Historical	No	No	No	No	No	No	Yes	No	Yes	Yes
	Appalachian Power Co.	Virginia	Electric	Historical	No	No	No	No	Yes	No	No	Yes	Yes	Yes
	Appalachian Power Co./Wheeling Power Co.	West Virginia	Electric	Historical	No	No	No	No	No	No	No	Yes	Yes	Yes
Avista Corporation	Alaska Electric Light & Power Co.	Alaska	Electric	Historical	No	No	No	No	No	No	No	No	No	Yes
	Avista Corp.	Idaho	Electric	Historical	Full	No	No	Yes	No	No	No	No	No	Yes w/ sharing
	Avista Corp.	Idaho	Gas	Historical	Full	No	No	Yes	No	No	No	No	No	Yes
	Avista Corp.	Oregon	Gas	Fully Forecast	Partial	No	No	Yes	No	No	No	No	No	Yes
	Avista Corp.	Washington	Electric	Historical	Full	No	No	Yes	No	No	No	No	No	Yes w/ sharing
	Avista Corp.	Washington	Gas	Historical	Full	No	No	Yes	No	No	No	No	No	Yes w/ sharing
CMS Energy Corporation	Consumers Energy Co.	Michigan	Electric	Fully Forecast	No	No	No	No	No	Yes	No	No	Yes	Yes
	Consumers Energy Co.	Michigan	Gas	Fully Forecast	Partial	No	No	Yes	No	No	No	No	No	Yes
Duke Energy Corporation	Duke Energy Florida LLC	Florida	Electric	Fully Forecast	No	No	No	No	Yes	Yes	No	Yes	Yes	Yes
	Duke Energy Indiana LLC	Indiana	Electric	Historical	Partial	No	No	Yes	No	Yes	Yes	Yes	Yes	Yes
	Duke Energy Kentucky Inc.	Kentucky	Electric	Fully Forecast	Partial	No	No	Yes	No	No	No	Yes	Yes	Yes
	Duke Energy Kentucky Inc.	Kentucky	Gas	Fully Forecast	Partial	No	No	Yes	No	No	Yes	No	Yes	Yes
	Duke Energy Carolinas LLC/Duke Energy Progr	North Carolina	Electric	Historical	No	No	No	No	No	Yes	No	Yes	Yes	Yes
	Piedmont Natural Gas Co. Inc.	North Carolina	Gas	Historical	Full	No	No	Yes	No	No	Yes	No	Yes	Yes
	Duke Energy Ohio Inc.	Ohio	Electric	Partially Forecast	Partial	No	No	Yes	No	Yes	Yes	No	Yes	Yes
	Duke Energy Ohio Inc.	Ohio	Gas	Partially Forecast	No	No	Yes	Yes	No	No	Yes	Yes	Yes	Yes
	Duke Energy Carolinas LLC/Duke Energy Progr	South Carolina	Electric	Historical	No	No	No	No	No	Yes	No	Yes	Yes	Yes
	Piedmont Natural Gas Co. Inc.	South Carolina	Gas	Historical	Partial	No	No	Yes	No	No	No	No	No	Yes
	Piedmont Natural Gas Co. Inc.	Tennessee	Gas	Fully Forecast	Partial	No	No	Yes	No	No	Yes	No	Yes	Yes

Proxy Group Company	Operating Subsidiary	Jurisdiction	Service	[1] Test Year	[2] Revenue Decoupling	[3] Formula-Based Rates	[4] Straight Fixed-Variable	[5] Total	[6] Traditional Generation	[7] Renewables/Non-Traditional Generation	[8] Delivery Infrastructure	[9] Environmental Compliance	[10] Total	[11] Fuel Adjustment Clause
					Decoupling / Revenue Stabilization				Capital Cost Recovery					
Entergy Corporation	Entergy Arkansas LLC	Arkansas	Electric	Fully Forecast	Partial	Yes	No	Yes	Yes	Yes	Yes	No	Yes	Yes
	Entergy New Orleans LLC	Louisiana-NOCC	Electric	Partially Forecast	No	Yes	No	Yes	No	Yes	No	Yes	Yes	Yes
	Entergy New Orleans LLC	Louisiana-NOCC	Gas	Partially Forecast	No	Yes	No	Yes	No	No	No	No	No	Yes
	Entergy Louisiana LLC	Louisiana	Electric	Historical	Partial	Yes	No	Yes	No	No	No	Yes	Yes	Yes
	Entergy Louisiana LLC	Louisiana	Gas	Historical	No	Yes	No	Yes	No	No	Yes	No	Yes	Yes
	Entergy Mississippi LLC	Mississippi	Electric	Fully Forecast	Partial	Yes	No	Yes	No	No	No	No	No	Yes
	Entergy Texas Inc.	Texas	Electric	Historical	No	No	No	No	Yes	No	Yes	No	Yes	Yes
Evergy, Inc.	Evergy Kansas Central Inc	Kansas	Electric	Historical	Partial	No	No	Yes	No	Yes	No	Yes	Yes	Yes
	Evergy Metro Inc.	Kansas	Electric	Historical	No	No	No	No	No	No	Yes	No	Yes	Yes
	Evergy Metro Inc	Missouri	Electric	Historical	Partial	No	No	Yes	No	No	Yes	No	Yes	Yes w/ sharing
	Evergy Missouri West Inc.	Missouri	Electric	Historical	Partial	No	No	Yes	No	Yes	Yes	No	Yes	Yes w/ sharing
IDACORP, Inc.	Idaho Power Co.	Idaho	Electric	Partially Forecast	Full	No	No	Yes	No	No	No	No	No	Yes w/ sharing
	Idaho Power Co.	Oregon	Electric	Partially Forecast	No	No	No	No	No	No	No	No	No	Yes
NextEra Energy, Inc.	Florida Power & Light Co.	Florida	Electric	Fully Forecast	No	No	No	No	Yes	Yes	No	Yes	Yes	Yes
	Pivotal Utility Holdings Inc.	Florida	Gas	Fully Forecast	No	No	No	No	No	No	Yes	Yes	Yes	Yes
	Lone Star Transmission LLC	Texas	Electric	Historical	No	No	No	No	No	No	Yes	No	Yes	n/a
NorthWestern Corporation	NorthWestern Corporation	Montana	Electric	Historical	No	No	No	No	No	No	No	No	No	Yes w/ sharing
	NorthWestern Corporation	Montana	Gas	Historical	No	No	No	No	No	No	No	No	No	Yes
	NorthWestern Corporation	Nebraska	Gas	Historical	No	No	No	No	No	No	No	No	No	Yes
	NorthWestern Corporation	South Dakota	Electric	Historical	No	No	No	No	No	No	No	No	No	Yes
	NorthWestern Corporation	South Dakota	Gas	Historical	No	No	No	No	No	No	No	No	No	Yes
OGE Energy Corporation	Oklahoma Gas & Electric	Arkansas	Electric	Historical	Partial	No	Yes	Yes	No	No	Yes	No	Yes	Yes
	Oklahoma Gas & Electric	Oklahoma	Electric	Historical	Partial	No	Yes	Yes	No	No	Yes	Yes	Yes	Yes
Pinnacle West Capital Corporatior	Arizona Public Service Co.	Arizona	Electric	Historical	Partial	No	No	Yes	No	Yes	No	Yes	Yes	Yes
Portland General Electric Compan	Portland General Electric Co.	Oregon	Electric	Fully Forecast	No	No	No	No	Yes	Yes	No	Yes	Yes	Yes
Southern Company	Alabama Power Co.	Alabama	Electric	Historical	No	Yes	No	Yes	Yes	Yes	No	Yes	Yes	Yes
	Atlanta Gas Light Co.	Georgia	Electric	Fully Forecast	No	Yes	No	Yes	No	No	Yes	Yes	Yes	Yes
	Georgia Power Co.	Georgia	Gas	Fully Forecast	No	Yes	Yes	Yes	Yes	No	No	Yes	Yes	n/a
	Northern Illinois Gas Co.	Illinois	Gas	Fully Forecast	Partial	No	No	Yes	No	No	Yes	Yes	Yes	Yes
	Mississippi Power Co.	Mississippi	Electric	Fully Forecast	Partial	Yes	No	Yes	No	No	No	Yes	Yes	Yes
	Chattanooga Gas Co.	Tennessee	Gas	Historical	Partial	Yes	No	Yes	No	No	No	No	No	Yes
	Virginia Natural Gas Inc.	Virginia	Gas	Historical	Partial	No	No	Yes	No	No	Yes	No	Yes	Yes
Xcel Energy Inc.	Public Service Co. of Colorado	Colorado	Electric	Historical	Partial	No	No	Yes	No	Yes	No	No	Yes	Yes
	Public Service Co. of Colorado	Colorado	Gas	Historical	Partial	No	No	Yes	No	No	Yes	No	Yes	Yes
	Northern States Power Co.-Minnesota	Minnesota	Electric	Fully Forecast	Partial	Yes	No	Yes	No	Yes	No	Yes	Yes	Yes
	Northern States Power Co.-Minnesota	Minnesota	Gas	Fully Forecast	No	No	No	No	No	No	Yes	No	Yes	Yes
	Southwestern Public Service Co.	New Mexico	Electric	Historical	No	No	No	No	No	Yes	No	No	Yes	Yes
	Northern States Power Co.-Minnesota	North Dakota	Electric	Fully Forecast	No	No	No	No	No	Yes	Yes	No	Yes	Yes
	Northern States Power Co.-Minnesota	North Dakota	Gas	Fully Forecast	No	No	Yes	Yes	No	No	No	No	No	Yes
	Northern States Power Co.-Minnesota	South Dakota	Electric	Historical	Partial	No	No	Yes	Yes	No	Yes	Yes	Yes	Yes
	Southwestern Public Service Co.	Texas	Electric	Historical	No	No	No	No	No	No	No	No	No	Yes
	Northern States Power Co.-Wisconsin	Wisconsin	Electric	Fully Forecast	No	No	No	No	No	No	No	No	No	Yes
	Northern States Power Co.-Wisconsin	Wisconsin	Gas	Fully Forecast	No	No	No	No	No	No	No	No	No	Yes

Proxy Group Average	Fully Forecast	30	Yes	50	Yes	56	Yes	67
	Partially Forecas	7	No	33	No	27	Yes w/ sharing	7
	Historical	46						
	% with ForecastTest Year:	44.6%	% with Form of Revenue Stabilization	60.2%	% with Form of Capital Cost Recovery	67.5%	% with Full FCA Cost Recovery	90.5%

Proxy Group Company	Test Year	Revenue Decoupling	Formula-Based Rates	Straight Fixed-Variable	Total	Traditional Generation	Renewables/Non-Traditional Generation	Delivery Infrastructure	Environmental Compliance	Total	Fuel Adjustment Clause
PacifiCorp (Oregon) [11]	Historical	No	No	No	No	Yes	Yes	No	Yes	Yes	Yes w/ sharing

Notes:
[1] Regulatory Research Associates, effective as of November 30, 2023
[2] S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated July 18, 2022. Operating subsidiaries not covered in this report were excluded from this exhibit.
[3] Company Form 10-K, Company Tariffs, S&P Capital IQ Pro
[4] S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated July 18, 2022.
[5] Equals IF(AND([2]=No, [3]=No, [4]=No), No, Yes)
[6] - [9] S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated July 18, 2022.
[10] Equals IF(AND([6]=No, [7]=No, [8]=No, [9]=No), No, Yes)
[11] S&P Global Market Intelligence, Regulatory Focus: Adjustment Clauses, dated July 18, 2022.

Docket No. UE 433
Exhibit PAC/414
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Ann E. Bulkley

RRA Ranking Analysis

February 2024

COMPARISON OF OG&E AND PROXY GROUP COMPANIES
RRA JURISDICTIONAL RANKINGS

		[1]	[2]
		RRA	
	Operation State	Rank	Numeric Rank
ALLETE, Inc.	Minnesota	Average/2	5
Alliant Energy Corporation	Iowa	Above Average/3	3
	Wisconsin	Above Average/3	3
Ameren Corporation	Illinois	Average/2	5
	Missouri	Average/3	6
American Electric Power Company, Inc.	Arkansas	Average/1	4
	Indiana	Average/1	4
	Kentucky	Average/2	5
	Louisiana	Average/2	5
	Michigan	Above Average/3	3
	Ohio	Average/2	5
	Oklahoma	Average/3	6
	Tennessee	Above Average/3	3
	Texas	Average/3	6
	Virginia	Average/2	5
	West Virginia	Below Average/1	7
Avista Corporation	Alaska	Below Average/1	7
	Idaho	Average/2	5
	Oregon	Average/2	5
	Washington	Average/3	6
CMS Energy Corporation	Michigan	Above Average/3	3
Duke Energy Corporation	Florida	Above Average/2	2
	Indiana	Average/1	4
	Kentucky	Average/2	5
	North Carolina	Above Average/3	3
	Ohio	Average/2	5
	South Carolina	Average/3	6
	Tennessee	Above Average/3	3
Entergy Corporation	Arkansas	Average/1	4
	Louisiana (NOCC)	Average/3	6
	Louisiana	Average/2	5
	Mississippi	Above Average/3	3
	Texas	Average/3	6
Evergy, Inc.	Kansas	Below Average/1	7
	Missouri	Average/3	6
IDACORP, Inc.	Idaho	Average/2	5
	Oregon	Average/2	5

COMPARISON OF OG&E AND PROXY GROUP COMPANIES
RRA JURISDICTIONAL RANKINGS

		[1]	[2]
		RRA	
	Operation State	Rank	Numeric Rank
NextEra Energy, Inc.	Florida	Above Average/2	2
	Texas	Average/3	6
NorthWestern Corporation	Montana	Below Average/1	7
	Nebraska	Average/1	4
	South Dakota	Average/2	5
OGE Energy Corporation	Arkansas	Average/1	4
	Oklahoma	Average/3	6
Pinnacle West Capital Corporation	Arizona	Below Average/3	9
Portland General Electric Company	Oregon	Average/2	5
Southern Company	Alabama	Above Average/1	1
	Georgia	Above Average/2	2
	Illinois	Average/2	5
	Mississippi	Above Average/3	3
	Tennessee	Above Average/3	3
	Virginia	Average/2	5
Xcel Energy Inc.	Colorado	Average/1	4
	Minnesota	Average/2	5
	New Mexico	Below Average/1	7
	North Dakota	Average/1	4
	South Dakota	Average/2	5
	Texas	Average/3	6
	Wisconsin	Above Average/3	3
Proxy Group Average		Average 1 - Average/2	4.69
PacifiCorp	Oregon	Average/2	5

Notes
[1] State Regulatory Evaluations, Regulatory Research Associates, December 8, 2023.
[2] AA/1= 1, AA/2= 2, AA/3= 3, A/1= 4, A/2= 5, A/3=6, BA/1= 7, BA/2= 8, BA/3= 9

Docket No. UE 433
Exhibit PAC/415
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Ann E. Bulkley

S&P Credit Supportiveness Ranking Analysis

February 2024

COMPARISON OF S&P JURISDICTIONAL RANKINGS

		[1]	[2]
		S&P	
		Rank	Numeric Rank
ALLETE, Inc.	Minnesota	Highly credit supportive	2
Alliant Energy Corporation	Iowa	Most credit supportive	1
	Wisconsin	Most credit supportive	1
Ameren Corporation	Illinois	Very credit supportive	3
	Missouri	Very credit supportive	3
American Electric Power Company, Inc.	Arkansas	Highly credit supportive	2
	Indiana	Highly credit supportive	2
	Kentucky	Most credit supportive	1
	Louisiana	Highly credit supportive	2
	Michigan	Most credit supportive	1
	Ohio	Very credit supportive	3
	Oklahoma	Very credit supportive	3
	Tennessee	Highly credit supportive	2
	Texas	Very credit supportive	3
	Virginia	Highly credit supportive	2
	West Virginia	Very credit supportive	3
Avista Corporation	Alaska	More credit supportive	4
	Idaho	Very credit supportive	3
	Oregon	More credit supportive	4
	Washington	Very credit supportive	3
CMS Energy Corporation	Michigan	Most credit supportive	1
Duke Energy	Florida	Most credit supportive	1
	Indiana	Highly credit supportive	2
	Kentucky	Most credit supportive	1
	North Carolina	Highly credit supportive	2
	Ohio	Very credit supportive	3
	South Carolina	More credit supportive	4
	Tennessee	Highly credit supportive	2
Entergy	Arkansas	Highly credit supportive	2
	Louisiana-NOCC	More credit supportive	4
	Louisiana	Highly credit supportive	2
	Mississippi	Very credit supportive	3
	Texas	Very credit supportive	3
Evergy, Inc.	Kansas	Highly credit supportive	2
	Missouri	Very credit supportive	3
IDACORP, Inc.	Idaho	Very credit supportive	3
	Oregon	More credit supportive	4
NextEra Energy, Inc.	Florida	Most credit supportive	1
	Texas	Very credit supportive	3
NorthWestern Corporation	Montana	More credit supportive	4
	Nebraska	Very credit supportive	3
	South Dakota	Very credit supportive	3
OGE Energy Corporation	Arkansas	Highly credit supportive	2
	Oklahoma	Very credit supportive	3
Pinnacle West Capital Corporation	Arizona	More credit supportive	4
Portland General Electric Company	Oregon	More credit supportive	4

COMPARISON OF S&P JURISDICTIONAL RANKINGS

		[1]	[2]
		S&P	
		Rank	Numeric Rank
Southern Company	Alabama	Most credit supportive	1
	Georgia	Highly credit supportive	2
	Illinois	Very credit supportive	3
	Mississippi	Very credit supportive	3
	Tennessee	Highly credit supportive	2
	Virginia	Highly credit supportive	2
Xcel Energy Inc.	Colorado	Very credit supportive	3
	Minnesota	Highly credit supportive	2
	North Dakota	Highly credit supportive	2
	New Mexico	Credit supportive	5
	South Dakota	Very credit supportive	3
	Texas	Very credit supportive	3
	Wisconsin	Most credit supportive	1
Proxy Group Average		Highly credit supportive / Very credit supportive	2.53
PacifiCorp	Oregon	More credit supportive	4

Notes
[1] Updated Views on North American Utility Regulatory Jurisdictions, Standard and Poor's Ratings Services, July 10, 2023
[2] Most= 1, Highly= 2, Very= 3, More= 4, Credit Supportive= 5

Docket No. UE 433
Exhibit PAC/416
Witness: Ann E. Bulkley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Ann E. Bulkley

Capital Structure Analysis

February 2024

CAPITAL STRUCTURE ANALYSIS

		Most Recent 8 Quarters (2021Q3 - 2023Q2)			
Proxy Group Company	Ticker	Common Equity Ratio	Long-Term Debt Ratio	Preferred Equity Ratio	Total Capitalization
ALLETE, Inc.	ALE	58.62%	41.38%	0.00%	100.00%
Alliant Energy Corporation	LNT	52.09%	47.71%	0.19%	100.00%
Ameren Corporation	AEE	53.17%	46.26%	0.57%	100.00%
American Electric Power Company, Inc.	AEP	47.91%	52.09%	0.00%	100.00%
Avista Corporation	AVA	49.76%	50.24%	0.00%	100.00%
CMS Energy Corporation	CMS	51.59%	48.21%	0.19%	100.00%
Duke Energy Corporation	DUK	52.77%	47.23%	0.00%	100.00%
Entergy Corporation	ETR	47.31%	52.59%	0.10%	100.00%
Evergy, Inc.	EVRG	61.10%	38.90%	0.00%	100.00%
IDACORP, Inc.	IDA	53.66%	46.34%	0.00%	100.00%
NextEra Energy, Inc.	NEE	61.26%	38.74%	0.00%	100.00%
NorthWestern Corporation	NWE	49.29%	50.71%	0.00%	100.00%
OGE Energy Corporation	OGE	53.98%	46.02%	0.00%	100.00%
Pinnacle West Capital Corporation	PNW	50.99%	49.01%	0.00%	100.00%
Portland General Electric Company	POR	45.52%	54.48%	0.00%	100.00%
Southern Company	SO	55.70%	44.06%	0.24%	100.00%
Xcel Energy Inc.	XEL	54.44%	45.56%	0.00%	100.00%
Average		52.89%	47.03%	0.08%	
Median		52.77%	47.23%	0.00%	
Maximum		61.26%	54.48%	0.57%	
Minimum		45.52%	38.74%	0.00%	

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 433
Exhibit PAC/500
Witness: Robert S. Mudge

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Robert S. Mudge

February 2024

TABLE OF CONTENTS

ATTACHED EXHIBITS

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, position, and business address.

A. My name is Robert S. Mudge. I am a Principal at The Brattle Group (Brattle), an international consulting firm providing planning, policy analysis, and valuation support in energy and regulatory economics, commercial litigation support, and competition analysis. My business address is 1800 M Street NW, Suite 700 North, Washington, DC 20036.

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 Company).

Q. Please describe your education and professional experience.

A. I am a former investment and commercial banker, consulting to various energy clients on issues relating to valuation, liquidity, corporate restructuring, contract terminations or amendments, special capital needs, acquisitions and divestitures, and the cost of capital. I also have practical experience as a Chief Financial Officer having served in that role for Brattle for several years. I received an M.B.A. in Finance and Economics from the University of Chicago Graduate School of Business and a B.A. from Harvard College.

I co-authored a white paper in 2018 describing the asymmetric nature and estimated cost of wildfire damage cost exposure, which my colleague, Frank C. Graves, introduced in testimony on behalf of Pacific Gas and Electric Company (PG&E) (FERC Docket No. ER19-13-000). The 2018 white paper was augmented in 2019 by an additional analysis to reflect the new terms and conditions for wildfire damages funding under California Assembly Bill 1054 (AB 1054). I testified jointly with Mr. Graves on these matters on behalf of both PG&E and Southern California Edison (SCE) before the California Public Utilities Commission (CPUC) in September 2019.

I have attached as Exhibit PAC/501 a statement of qualifications that further details my background and professional experience. I am also sponsoring the following exhibits:

Exhibit PAC/502—Area Burned from Human Caused Wildfires in the West

Exhibit PAC/503—Costs of +$1 Billion Wildfires in the United States

Exhibit PAC/504—Recent Costs of Wildfire Insurance Faced by Regional Utilities

Exhibit PAC/505—Recent Wildfire Insurance Cost Recovery Settlements Achieved by Regional Utilities

Q. Have you appeared as a witness in previous regulatory proceedings?

A. Yes. I have testified before other public utility commissions in Alaska, Alberta, California, Illinois, Kentucky, Massachusetts, Michigan, and Missouri.

II. PURPOSE OF TESTIMONY AND SUMMARY CONCLUSIONS

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

A. The purpose of my testimony is to provide context for current PacifiCorp initiatives to manage the growing risk of financial exposure to wildfire-related liabilities as described in the testimony of Company witness Joelle R. Steward. These initiatives include seeking approval for the following:

1. An Insurance Cost Adjustment that will recover the increased costs for excess liability insurance and enable the Company to annually procure insurance for

third-party liability using the most economical combination of commercial insurance and self-insurance through a new Insurance Mechanism that the Company is developing, and

2. A Catastrophic Fire Fund that will facilitate creation of a multi-state risk pool for potential catastrophic events where third-party liabilities are in excess of the Company's insurance coverage.

Toward this objective, I review indicia of increased wildfire risk affecting the Western United States (U.S.), the resulting financial exposure faced by regional electric utilities, the experience of those utilities in managing that financial exposure, and related implications for PacifiCorp's proposed remedies.

Q. Please summarize the principal conclusions of your direct testimony.

A. I find that the structure and evolving terms of PacifiCorp's proposed remedies to growing wildfire exposure are reasonable based on observable threats and the resulting financial exposure, increasing limitations (high cost, limited availability) of traditional risk management tools to address such large exposures, and the precedents established in other jurisdictions, particularly California.

More specifically, this conclusion is premised on the following:

- PacifiCorp is facing an exogenous, largely climate-induced phenomenon. Growing wildfire risk is similarly afflicting many other electric utilities and society at large.
- With wildfire risks mounting, demand for wildfire insurance is expanding at the same time as the supply of insurers willing to bear wildfire risk (and catastrophic climate-event risk generally) is contracting. Unsurprisingly, the

current supply/demand imbalance is resulting in much higher costs per dollar of coverage. Company witness Mariya V. Coleman discusses the challenges of procuring excess liability insurance for the 2024-2025 policy year.

- Electric utilities in PacifiCorp's region have both (i) faced dramatic increases in the levels and unpredictability of wildfire insurance costs, and (ii) crafted workable solutions for those costs in recent rate-case proceedings. These solutions appropriately recognize wildfire insurance as a legitimate cost of service and form useful precedents for PacifiCorp's recovery of such costs.
- As a separate matter, to the degree commercial insurance markets become dysfunctional—e.g., if insurance premia offered to PacifiCorp rise to levels in excess of statistically expected losses, or if the availability of such insurance should simply dry up to where it is not possible to obtain any incremental coverage—it may make sense to replace commercial insurance with self-insurance (which formed the basis for recent settlements in California). PacifiCorp is thus proposing contingent authorization to substitute self-insurance for commercial insurance.
- Importantly, even if PacifiCorp is able to recover increased costs for customary amounts of wildfire liability insurance, it still faces potential rare but catastrophic exposure to unprecedented levels of extreme wildfire loss claims that I understand may be uninsurable at any cost in commercial markets. Such worst-case events could be crippling to PacifiCorp's financial stability and potentially disruptive to normal utility operations. PacifiCorp is

therefore additionally proposing a new Catastrophic Fire Fund—above and beyond customary coverage—to absorb such extreme losses.

- Subject to compliance with reasonable mitigation standards, extreme wildfire loss claims (if they occur) should be viewed as costs of utility service recoverable from customers (just as insurance premia normally are). This is because such losses are a residual risk made inevitable under rational utility management. It is unrealistic to expect that PacifiCorp (or any other utility) could avoid extreme wildfire losses through physical mitigation alone, which is limited by the extreme difficulties of anticipating extreme weather, vast geography, finite capital resources, and diminishing marginal returns to wildfire mitigation investment. Put another way, mitigation can reduce the likelihood of fire events, but external circumstances largely determine the damage from them.
- Customers and regulators themselves will also recognize these factors in resisting large upfront costs for wildfire mitigation. Thus, some form of agreed, socialized cost recovery for these adverse possible situations should be developed before they arise.

Importantly at this time, PacifiCorp is continuing to assess the magnitude of wildfire liability risk expected to affect its service territories and expects to complete an assessment in in March 2024.

III. REGIONAL WILDFIRE RISK AND COST ARE GROWING

Q. Please describe the landscape of wildfire occurrence in the West and beyond in recent years.

A. Wildfire risk is a growing and menacing global phenomenon, which has had a material adverse impact on diverse businesses and individuals far beyond Oregon in recent years and months. Major wildfire risk zones have been identified in geographies as diverse as Europe, Australia, Canada, South America, and the Western U.S.[1] In North America, wildfire risk has become a chronic issue, i.e. more frequent, larger, and more consequential (similar to other climate-driven natural disasters in the rest of the U.S. and around the world). For example, recent analysis of human-caused wildfires in the west by the National Interagency Fire Center shows an approximately five-fold increase in acres burned annually from 2001 to 2022 (see also Exhibit PAC/502).[2] The bulk of this occurred in the western states—mostly in California but recently including the Pacific Northwest. Recent wildfires have had devastating consequences for electric utilities in California and Hawaii, as well as Colorado, Idaho, Oregon, Washington, and Texas.[3]

Q. How has this increase been correlated with the growth in other extreme weather events?

A. The increasing frequency and severity of wildfires has occurred in parallel with climate change generally, as well as other climate-related natural disasters such as

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[1] https://www.marshmclennan.com/insights/publications/2019/oct/wildfire-paper--oct--2019-.html. *See also, Wildfires on Chile's Coast Kill 112 and Leave Hundreds Missing*, New York Times, Feb. 4, 2024.
[2] National Interagency Fire Center, "Wildfires and Acres", Oct. 1, 2023, https://www.nifc.gov/fire-information/statistics/human-caused. The west includes the Northwest, California, Northern Rockies, Great Basin, and Southwest regions.
[3] S&P Global Ratings, *A Storm is Brewing: Extreme Weather Events Pressure North American Utilities' Credit Quality* (Nov. 9, 2023).

floods, hurricanes, and severe cold-weather storms. It is intuitive that wildfire risk can be both widespread and increasingly severe and damaging, since it is largely a function of the effects of climate change interacting with residential and commercial growth in locations already prone to ignition (the so-called wildland-urban interface, or WUI). Conditions such as high temperatures and low precipitation have been linked to extended fire seasons, exacerbating weather conditions such as high winds, and near inability to predict the behavior of individual fires.[4]

Q. What about the cost impact of wildfires?

A. The cost impact of wildfires has grown with the physical impact. Globally, the pace of reported economic losses from wildfires have more than doubled since 2015 relative to the prior 15 years.[5] This step-change is even more pronounced for the U.S., where, comparing the same time period, economic losses have increased five-fold, and in some years amounted to many tens of billions of dollars (see Exhibit PAC/503).[6]

Q. How have affected utilities insured against this risk?

A. Utilities have customarily obtained commercial insurance to cover multiple liabilities including wildfires on a bundled basis. In limited instances, utilities have augmented commercial insurance with capital market instruments to cover highly specified risks such as wildfires in the form of so-called "Catastrophe Bonds". More recently, as

[4] Next-Generation Fire and Vegetation Modeling for a Hot and Dry Future, Federation of American Scientists, June 20, 2023.
[5] Aon, 2023 Weather, Climate and Catastrophe Insight.
[6] National Oceanic and Atmospheric Administration – National Centers for Environmental Information U.S. Billion-Dollar Weather and Climate Disasters (2023), https://www.ncei.noaa.gov/access/billions/state-summary/US.

further described below, utilities in California have turned to self-insurance specifically for wildfires.

Q. How has the growth in extreme events affected the availability of commercial insurance?

A. Risks stemming from climate change and wildfires have contributed to a tightening of coverage availability provided by the commercial insurance industry. The industry has noted that "many risk buyers [seeking insurance coverage] are challenged to find adequate coverage for their natural catastrophe-prone exposures."[7] In response to significant and severe losses and "limitations" in effectively modeling future catastrophes, many insurance providers have chosen to "de-risk or withdraw" from offering certain coverages.[8] The problem appears to be anxiety over the rising frequency and costs of fire events and the correlated problems with other climate related risks.[9]

Q. Have these climate change and wildfire risks affected the availability of commercial insurance for electric utilities, including for PacifiCorp?

A. Yes. PacifiCorp has encountered recent difficulty in obtaining wildfire liability insurance. As explained by Company witness Coleman, insurers who historically

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[7] Aon, *Climate and Catastrophe Insight,* at 29 (2024).
[8] Howden, *The Great Realignment* at 14 (2023), accessed at https://www.howdengroup.com/sites/g/files/mwfley566/files/2023-01/the-great-realignment-report-2023.pdf. *See also*, p. 11: "Persistent and elevated catastrophe losses, along with the attendant issue of catastrophe model efficacy, continued to drive sentiment in property lines amidst concerns that changing weather patterns are increasing both the frequency and severity of climate-sensitive perils. Higher retentions, tighter terms and reduced frequency coverage (i.e. aggregates, lower excess-of-loss layers, quota shares) reflected reinsurers' resolve to focus more on capital protection after six consecutive years of above-average catastrophe losses."
[9] *See*, Claire Wilkinson, *Utilities contractors challenged in finding wildfire coverage,* Business Insurance, accessed at https://www.businessinsurance.com/article/20210525/NEWS06/912342050/Utilities-contractors-challenged-in-finding-wildfire-coverage: "The lack of interest from the marketplace to cover wildfire risks, in general, has 'spread like a wildfire' beyond California and throughout the country…".

would consider selling wildfire liability will no longer do so.

This experience is hardly unique to PacifiCorp or other Berkshire Hathaway Energy entities. In the course of its 2023 general rate case (GRC) process, PG&E reported that "there has been a significant decrease in the number of insurers offering wildfire coverage to California [investor owned utilities (IOUs)]."[10] This situation has led to PG&E receiving anemic insurance company responses to recent wildfire insurance solicitations, reporting only 16 offers to 73 inquiries in 2021.[11] The trend was observed as early as 2017, when SCE was already noting a "diminishing general liability and wildfire insurance market in California for investor-owned utilities, to the extent even available."[12]

Q. How has increased wildfire risk affected the cost of commercial insurance?

A. Increased wildfire risk has led to sharp increases in the cost of wildfire liability insurance for utilities. Company witnesses Coleman and Steward address the cost increases experienced by PacifiCorp. This reflects both the increasing burden on the insurance industry from rising claims and the much more difficult risk estimation that has accompanied the global warming aspects of the problem. For instance, the current wildfire operational models are deemed "incapable" of simulating and accounting for the "substantial ecosystem changes that are occurring from climate change."[13]

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[10] *Application of Pacific Gas and Electric Company for Authority, Among Other Things, to Increase Rates and Charges for Electric and Gas Service on January 1, 2023,* Application (A.) 21-06-021, Exhibit 9, Chapter 3 at 3-23.
[11] *Id.*, p. 3-26.
[12] Letter from Russell G. Worden to Timothy J. Sullivan, "Letter of notification establishing a Z-Factor for costs associated with incremental wildfire-related liability insurance," at 2–3 (Dec. 29, 2017).
[13] Matthew Hurteau, *Next-Generation Fire and Vegetation Modeling for a Hot and Dry Future,* Federation of American Scientists (June 20, 2023), accessed at https://fas.org/publication/next-generation-fire-and-vegetation-modeling-for-a-hot-and-dry-future/.

While frequently not made public, wildfire insurance costs and coverage levels have been made available in financial and regulatory filings by the California IOUs. More limited insurance data has been provided by other utilities in the west, such as Avista Corporation and Idaho Power Company (Idaho Power) in the course of regulatory filings. Insurance cost data is summarized in Exhibit PAC/504[14] and placed in context relative to insurance coverage levels (where available) and operating and maintenance (O&M) expense.[15]

- *PG&E*—PG&E has experienced the sharpest cost increases, with wildfire liability insurance costs growing by approximately a factor of ten since 2017 in both absolute terms and costs per dollar of coverage.[16] For the period 2022-2023, PG&E's wildfire liability insurance expense stood at $745 million, for coverage of $940 million.[17] Thus, for that period, PG&E was paying an effective wildfire liability insurance premium of 79 percent. PG&E's wildfire liability insurance expense for 2022-2023 comprised approximately 8 percent of total O&M expense for calendar 2022, versus approximately 1 percent in 2017.

  PG&E noted in its 2023 GRC application that "the difficulty of managing the company's risks through the commercial insurance market alone continues to be extremely challenging as does the prospect of accurately forecasting the costs to do so."[18] Among other things, the new market

[14] Note that regulatory orders approving the recovery of self-insurance costs are summarized below in Section V(A).
[15] Specifically, O&M costs omitting fuel and purchased power.
[16] A. 21-06-021, CPUC Decision (D.) 23-01-005 at Table 2 (Jan. 17, 2023) (the "PG&E Decision").
[17] *Id.*
[18] A.21-06-021, Application, Exhibit 9, Chapter 3 at 3-24.

conditions mean that "PG&E now procures most of its wildfire coverage separately from coverage for other perils, essentially creating two different insurance towers—one for wildfire and one for non-wildfire."[19]

- *SCE*—SCE has experienced similar, if less extreme, increases in wildfire insurance costs, with costs per dollar of coverage doubling since 2018, to 43 percent for the 2022-2023 period.[20] SCE's wildfire liability insurance expense stepped up from 9 percent of O&M in 2018 to nearly 13 percent on average for 2019-2021.

  In SCE's 2021 GRC request, SCE recognized that its wildfire liability insurance expense forecast of $624 million was "significantly higher than previous years, but that is not unexpected given the dramatically increased risks faced by electric utilities from wildfires, and the insurance industry's willingness to insure against those risks."[21] SCE observed further that these wildfire insurance market conditions were "well known to and [had] been frequently and explicitly recognized by the Commission."[22] SCE additionally noted that "in the current insurance environment, it is impossible to forecast wildfire liability insurance premiums precisely."[23]

- *SDG&E*—Similarly, SDG&E's wildfire liability insurance costs nearly tripled in absolute terms from the 2016-2017 period to 2022-2023, when they stood

[19] *Id.,* at 3-23.
[20] Edison International Form 10-K.
[21] *Application of Southern California Edison Company for Authority to Increase its Authorized Revenues for Electric Service in 2021, Among Other Things, and to Reflect that Increase in Rates,* A.19-08-013, Opening Brief of Southern California Edison Company at 238 (Sept. 11, 2020).
[22] *Id.*
[23] *Id.,* at 247.

at $221 million.[24] Assuming that SDG&E has maintained coverage levels of approximately $1.5 billion (as reported in SDG&E's 2020 cost of capital proceeding[25]), this represents an effective wildfire insurance premium of 15 percent for 2022-2023. As a percentage of O&M costs, SDG&E's wildfire liability insurance costs grew from approximately 8 percent in 2016 to 14 percent on average for 2019-2022.

In its 2024 GRC application, SDG&E noted that "[i]nsurance market uncertainty continues because of wildfire risk, inverse condemnation, and global catastrophe losses. Because of this uncertainty and continued volatility in the cost of liability insurance, SoCalGas and SDG&E request that the Commission reauthorize their [balancing accounts] for liability insurance premiums."[26]

- *Avista*—Avista reported a doubling in general liability insurance expense between 2020 and 2022, when costs reached $14 million.[27] This represented a near doubling in insurance expense as a percentage of O&M—from 1.8 percent to 3.3 percent—over the same period.

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[24] *Application of San Diego Gas & Electric Company for Authority, Among Other Things, to Update its Electric and Gas Revenue Requirement and Base Rates Effective on January 1, 2024,* A.22-05-016, SDG&E Prepared Direct Testimony of Dennis J. Gaughan (Corporate Center - Insurance), Table DG-18 (years 2021 and 2022 are forecasts) (May 2022).
[25] *Application of San Diego Gas & Electric Company,* A.19-04-017, Exhibit No. SDG&E-05, Prepared Direct Testimony of John J. Reed and James M. Coyne at 34 (Apr. 2019).
[26] A.22-05-016, SDG&E Prepared Direct Testimony of Dennis J. Gaughan (Corporate Center - Insurance) at DJG-24 (May 2022).
[27] *Avista Corporation v. WUTC,* Washington Utilities and Transportation Commission (WUTC), Docket Nos. UE-220053, UG-220054, UE-210854, Rebuttal Testimony of Elizabeth M. Andrews, Table 7 (August 19, 2022).

Avista identified these cost increases as "largely related to wildfire exposure in the industry at large, and especially in the West."[28] Avista further characterized the costs as "undoubtedly 'extraordinary' and volatile" relative to past years, and "beyond the Company's control, notwithstanding our best efforts under the Wildfire Resiliency Plan."[29]

- *Idaho Power*—Idaho Power reported a 64 percent increase in Excess Liability insurance expense between 2020 and 2022, when costs exceeded $14 million.[30] This represented a 46 percent increase in insurance expense as a percentage of O&M expense—from 2.3 percent to 3.3 percent—over the same period.

  Idaho Power has attributed these costs "to the frequency and magnitude of Western-state wildfires in recent years, as well as Idaho Power's specific wildfire risk."[31] Like other utilities, Idaho Power is a "price taker" when it comes to buying insurance. The Company notes that "[i]n that regard, despite annual assessment of its insurance portfolio to identify the best value and the retention of an experienced insurance broker, the Company is subject

[28] *Avista Corporation v. WUTC,* WUTC Docket Nos. UE-220053, UG-220054, UE-210854, Direct Testimony of Elizabeth M. Andrews, p. 70 (January 25, 2022).
[29] *Id.,* p. 68.
[30] *In the Matter of the Application of Idaho Power for an Accounting Order Authorizing the Deferral of Incremental Wildfire Mitigation and Insurance Costs,* Idaho Public Utilities Commission Case No. IPC-E-21-02, filed Jan. 22, 2021; *In the Matter of the Application of Idaho Power for Authority to Increase its Rates and Charges for Electric Service in the State of Idaho and for Associated Regulatory Account Treatment,* Idaho Public Utilities Commission (IPUC) Case No. IPC-E-23-11, Motion for Approval of Stipulation and Settlement, October 2023.
[31] *Application of Idaho Power for an Accounting Order Authorizing the Deferral of Incremental Wildfire Mitigation and Insurance Costs Before the Idaho Public Utilities Commission,* IPUC Case No. IPC-E-21-02, Application at 26 (Jan. 2021).

to price increases as insurers raise premiums due to losses, either pertaining to Idaho Power or to insurers' overall insured base."[32]

Q. How have increased wildfire risks otherwise affected electric utilities?

A. Perhaps inevitably, the interactions of wildfires and utility equipment have led to claims and court rulings against utilities. This has been exacerbated in California by the doctrine of "inverse condemnation"—under which I understand utilities automatically bear responsibility for wildfire damage claims involving their equipment or operations as a legal matter. Wildfire liability claims have been upheld against utilities in other states not necessarily subject to inverse condemnation as well.

Wildfire claims have aggregated in the tens of billions of dollars for the California IOUs (PG&E, SCE, and SDG&E), and, more recently, as much as $2.4 billion in probable losses accrued by PacifiCorp as of September 30, 2023.[33]

Q. Have there been adverse reactions from the credit rating agencies?

A. Yes. Credit rating agencies have been concerned with the risks of wildfires on utility credit profiles. As specifically discussed by Company witness Steward, the risk of wildfire liabilities was a cause for Standard & Poor's (S&P) and Moody's Investor Service (Moody's) to downgrade PacifiCorp's senior unsecured issuer rating during 2023. S&P downgraded PacifiCorp to BBB+ in June 2023, stating their belief that "the operating risks for PacifiCorp have significantly increased."[34] Moody's

[32] Idaho Public Utilities Commission, Case No. IPC-E-23-1, Direct Testimony of Brian R. Buckham at 34 (June 2023).
[33] PacifiCorp Form 10-Q for period ending September 30, 2023, at 23.
[34] S&P Global, *PacifiCorp Downgraded to 'BBB+', Outlook Revised to Negative; Berkshire Hathaway Energy Co. Outlook Also Negative* (June 20, 2023). S&P assessed PacifiCorp's "stand-alone credit profile" at BB+.

downgraded PacifiCorp to Baa1 in November 2023 and stated that "wildfire risk, a form of physical climate risk, was a key driver of the downgrade."[35]

These risks have affected credit profiles for electric utilities across the industry. As recently noted by S&P, "[d]amages and related costs from physical risks are escalating in North America as regions designated as high-fire risk expand."[36] Furthermore, S&P "has downgraded more [Investor Owned Utilities] due to physical events (e.g. hurricanes, storms, and wildfires) over the past six years by nearly 10 times compared with the previous 13 years."[37]

IV. WILDFIRE MITIGATION CANNOT REASONABLY ELIMINATE ALL RISK

Q. What are utilities currently doing to mitigate wildfire risk?

A. Some utilities in the West are re-evaluating their risk management protocols and cost recovery mechanisms to be more proactive for this kind of problem, including:

- Compiling better statistics on apparent risk over long periods of time (even if very difficult to do with any precision)—which allows them to at least evaluate what the price of risk is in offered insurance compared to their estimated loss exposure.[38]
- Formulating ex ante risk mitigation plans subject to agreement with regulators and intervenors that those plans are aggressive enough (spend enough but not

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[35] Moody's Investor Service, *Rating Action: Moody's downgrades PacifiCorp to Baa1, outlook stable* (Nov. 21, 2023).
[36] S&P Global, *A Storm Is Brewing: Extreme Weather Events Pressure North American Utilities' Credit Quality* (Nov. 9, 2023).
[37] *Id.*
[38] For example, CA utilities must submit public risk studies as part of the CPUC's periodic Risk Assessment and Mitigation Phase ("RAMP") proceedings. These studies are probabilistic in nature and address wildfire risk along with a variety of other risks. See https://www.cpuc.ca.gov/about-cpuc/divisions/safety-policy-division/risk-assessment-and-safety-analytics/risk-assessment-mitigation-phase.

too much money) and are prioritized for most likely effectiveness—with the intent that compliance with these plans will inoculate the utility against findings of imprudence and loss of cost recovery if/when disasters occur despite mitigation efforts.[39]

Q. Are these plans focused narrowly on wildfires or do they encompass multiple risks?

A. It varies. In many cases, insurance covers a suite of possible catastrophic problems of which wildfire is just one. Also for sizing of effort and priority among such risks, it is preferable if a utility's extreme risk management system is not designed piecemeal, one type of risk at a time (though this is not uncommon, as some hazards tend to occur rarely) but instead reflects some attempt to achieve equal benefits per dollar of effort put into mitigation across all major types of risks (such as cybersecurity, system safety, wildfires, earthquake recovery, extreme storm hardening and recovery). This is difficult because the types of damages across risk types are quite distinct, but to some extent they can be monetized or at least ranked in terms of dimensions like energy delivery disruption likelihood, frequency of occurrence, personnel and customer safety or survival risk, interaction with other critical systems, tendency to include property damage etc., and their mitigations can be ranked in terms of extent of the system and time frame of improved protection achieved by each. This allows an elementary comparison across risks for some degree of equivalent response

[39] Note, for example, protocols relating to accessing the California Wildfire Fund described below, which evaluate utility prudency "based on actions taken by a utility, not the outcome of those actions". *See* Safety Certification FAQ | Office of Energy Infrastructure Safety, https://energysafety.ca.gov/what-we-do/electrical-infrastructure-safety/wildfire-mitigation-and-safety/safety-certifications/safety-certification-faqs/.

planning. An integrated approach of this type lends further credibility to the plans for whatever are the strongest concerns.

Q. Why can't these efforts be relied upon to eliminate wildfire risk?

A. Even with the best of utility-sponsored fire mitigation plans, it is impossible (and too expensive even if it were possible in principle) to fully eliminate the wildfire risks in a large region.

This is true for several reasons:

- *Extreme weather poses an unpredictable threat*—Extreme weather amplifies the uncertainty range of consequences and damages of a given wildfire even if the mitigation plans reduce the risk of a wildfire outbreak occurrence. This means that the challenges are a moving target, and factors outside the control of the utility will significantly determine the extent of the outcome of consequences and damages of wildfires. As noted above, it has also made modeling of fire risk quite difficult and inconsistent with recently observed disasters.
- *Wildfire mitigation comprises a massive geographic challenge*—It is not possible to pinpoint exactly where the wildfires will start in the future, hence one cannot eliminate the wildfire events by preemptive measures at a specific location among many possible locations where a fire could start in a very large area encompassing multiple states. All possible areas need to be targeted, ideally in order of declining risk, which itself is a diagnostic that takes time to develop and implement.

- *Other responsible entities*—Responsibility to mitigate wildfire risks is typically distributed across multiple agencies and many individuals, with utility mitigation plans forming just one of many relevant factors.
- *Competing priorities of maintaining service quality*—The expected benefits of additional expenditures on wildfire mitigation plans has to be weighed against customer benefits from spending that money on other programs (reliability, resiliency, service efficiency, customer services, relative risk priority, etc.). Utility expenditures approved by regulators for wildfire mitigation plans typically represent a small portion of total revenue requirements.
- *Law of diminishing marginal returns to mitigation efforts*—Another consideration that limits the cost effectiveness of additional expenditures to be spent on wildfire mitigation plans by utilities is the economics "law" of diminishing marginal returns. That is the tendency of economic activities to be directed at the most valuable activities first and then to see declining value in subsequent efforts. Since the types of activities in the fire mitigation plans for a given total budget will (or should) be selected based on the greatest possible cost-effective impact in mitigating the wildfire risks, an expansion or continuation of the total budget will start pursuing activities that tend to have smaller and smaller incremental benefits. These declining marginal benefits ultimately justify putting a limit on how much improvement to pursue. In general, all forms of risk reduction become dramatically more expensive as the remaining expected risks decline. This is similar to why electric utilities in the U.S. have typically implemented a 1-in-10 years Loss of Load Expectation

threshold (or variations thereof) for determining planning reserve margins to maintain resource adequacy, instead of trying to eliminate all risk for reliability outage events.

Thus, residual risk is inevitable under even the most aggressive mitigation plan. And it is likely that associated damage claims will continue to occur. But wildfire mitigation plan effectiveness will gradually reduce the amount and cost of insurance otherwise needed.

Q. How should appropriate mitigation be determined?

A. In a regulatory setting, while the utility has the greatest expertise and best vantage point for assessing costs and benefits of any particular mitigation program, the process of determining appropriate mitigation efforts and protocols is as much negotiation as analysis, involving all stakeholders. Again, given the infeasibility of eliminating the risk, there must be a balance of interest among stakeholders about how far and fast to go, relative to using funds and resources for other important utility services. Similarly, the right amount and layering of insurance (commercial or self-provided) also needs this joint resolution, as insurance does not eliminate risk, it simply spreads out how the expected risk is paid for, and improves liquidity if/when the risk occurs. There is no per se right level of such smoothing, as this interacts (like mitigation) with other budgetary tradeoffs for the utility and its customers. The stakeholder workshops that PacifiCorp has been implementing are a good venue for such discussions.

V. POTENTIAL REGULATORY RELIEF

Q. Is a utility's wildfire risks and costs already compensated by its allowed return on equity (ROE) making regulatory mechanisms unnecessary?

A. No, wildfire risks and costs are not typically compensated by a utility's allowed ROE, nor would such compensation be very effective in the event it was allowed. This is recognized by regulators in the normal practice of providing for recovery of insurance costs above and beyond allowed ROEs, and applies all the more to increased insurance premia and/ or costs associated with extreme wildfire events. Exogenous risks like wildfire liability are not well captured in utility ROEs because of two types of asymmetry: 1) the one-sided nature of insurance risks generally and 2) the lack of any offsetting upside available to regulated utilities under cost of service rate making and cost of equity benchmarks that exclude idiosyncratic risks (such as wildfires affecting a particular utility).

Insurance costs are intuitively one-sided. The possible losses from insurance risks reduce the expected cash flows from an asset, but that reduction is not accompanied by any prospect of compensatory upside returns.

Q. Please elaborate with some examples.

A. For example, when a public company faces an economic loss from a third-party liability claim, its stock price will fall, all else equal. That stock will not be expected thereafter to appreciate more than similar companies that do not have that problem, and so shareholders will not have the opportunity to cover the unexpected loss.[40]

[40] Importantly, insurance losses can be diversified but they cannot be diversified *away*, which is unlike other business risk that involves a blend of uncorrelated economic outcomes, some positive and some negative.

The asymmetry problem is more severe for regulated utilities than for unregulated companies, which have at least the opportunity to choose when, where, how, and how much to invest, and therefore some chance of earning returns in excess of their cost of capital. Regulated utilities, by contrast, do not have this discretion, as they operate under an obligation to serve with cost-of-service pricing and very limited or no upside opportunities relative to allowed ROEs.

Q. What about allowing a premium ROE to cover asymmetric risk?

A. An allowed ROE could be augmented, in principle, by a premium to the customarily measured cost of capital to reflect asymmetric risk. However, there are multiple challenges to applying this ROE approach, not least that there are considerable estimation difficulties of the appropriate amount (given the recent growth in frequency and severity of wildfires) which make it possible that even a large premium only partly addresses the problem. At the same time, an allowance may create the incorrect impression in the eyes of the public and regulators that the utilities have been fully compensated for damage costs from all potential wildfire catastrophes.

Absent a meaningful opportunity to offset risk via returns on investment, it is essential that utilities have a variety of equitable cost recovery mechanisms such as recovering higher commercial insurance costs (possibly through self-insurance) and those discussed below.

A. Recovering Higher Commercial Insurance Costs

Q. How have increased wildfire liability insurance costs been handled by other utilities and their regulators?

A. The large increases in wildfire insurance costs described above have presented urgent challenges in cost recovery for affected utilities and their regulators. In particular, the cost recovery settlements achieved by the California IOUs ("California Precedents"), Avista and Idaho Power (together, the "Regional Precedents") provide useful context for PacifiCorp's filing. The Regional Precedents directly inform PacifiCorp's filing in the following ways:

- Regulatory acknowledgement of higher and more uncertain wildfire insurance costs,
- Regulatory recognition of exogenous drivers, and
- Self-insurance mechanisms similar to those currently being considered by PacifiCorp.

Importantly, the California Precedents further underscore the recognition of current uncertainty in wildfire liability insurance markets by authorizing the recovery of wildfire insurance costs on a contingent (i.e. formulaic) basis, as discussed further below.

Q. Please describe the California Precedents.

A. Given that the costs of commercial wildfire insurance have reached such high levels, the California IOUs have each recently been authorized or have settlements pending that would authorize recovery of very substantial wildfire self-insurance costs over multi-year periods.

The California Settlements are summarized below and in Exhibit PAC/505.

- *PG&E*—In CPUC Decision 23-01-005, issued in January 2023[41], PG&E was authorized to self-insure by setting aside funds potentially approaching recent commercial cost levels toward covering wildfire liability up to $1 billion annually for the "2023 GRC Period": 2023–2026.

In a "worst case" scenario assuming wildfire liability claims of $1 billion in each year of the 2023 GRC Period, the PG&E Settlement provided that 72 percent of realized costs would be recovered via PG&E's Risk Transfer Balancing Account (RTBA)[42] not subject to reimbursement "tied to the outcomes of reasonableness reviews."[43] In such a "worst case" scenario, most of the 28 percent portion remaining uncollected at the end of the 2023 GRC Period could be subsequently recovered from customers via a Tier 2 Advice Letter Filing,[44] with 5 percent paid by a shareholder deductible.[45]

Importantly, per the agreed Settlement formulas illustrated in Appendix B of the PG&E Settlement, the portion of claims recoverable not

[41] *See* CPUC A.21-06-021, PG&E Decision (approving settlement between PG&E, the Utility Reform Network, and the Public Advocates Office at the CPUC (PGE Settlement).
[42] The RTBA had been previously established in CPUC D.20-12-005 (Dec. 3, 2020) to "record the difference between the amounts authorized in this GRC and actual costs of insurance premiums for coverage up to $1.4 billion" (D.20-12-005 at 249). D.20-12-005 further noted that "[r]egarding the establishment of the RTBA, we agree that insurance costs for General Liability coverage has been difficult to predict in recent times because of market conditions and the recent wildfires in California. A two-way balancing account will also allow PG&E to address uncertainty in a timely manner and at the same time ensure that there is adequate insurance coverage" (D.20-12-005 at 254).
[43] *See* PG&E Decision, at 13, and PG&E Settlement Section 3.4 and Appendix B: "Illustrative Calculation Reflecting the Worst Case Scenario—Cost Recovery for Undercollections at the End of the 2023 GRC Period", the latter reflected in Exhibit 5.
[44] PG&E Settlement Section 3.7 and Appendix B. Note that a Tier 2 Advice Letter could be subject to challenge.
[45] PG&E Settlement Section 3.2.3.

subject to a reasonableness review could be increased significantly under a less adverse loss scenario. For example, were realized losses over the 2023 GRC Period limited to the level actually experienced for 2019-2021 ($458 million per year), such recoveries would grow to 93 percent.[46]

In support of the PG&E Settlement, the PG&E Decision acknowledged the insurance market realities affecting PG&E:

> "Due to a number of factors including PG&E's increased claims, the general liability insurance market continued to increase insurance premiums and reduce the availability of insurance to cover wildfire risk. As Table 2 illustrates, PG&E's wildfire liability insurance cost per limit of coverage grew until the costs reached 81.6 percent of the coverage amount for the 2020-21 insurance policy"[47]

As to self-insurance, the CPUC reasoned that "[s]ince 2017, wildfire liability insurance for third-party claims has risen to the point that self-insurance is likely to achieve sufficient insurance coverage at a lower overall cost to PG&E's customers than commercial insurance."[48] The PG&E Decision went on to say that "[n]ow that the cost of commercial insurance is up to 80 percent of the coverage it would provide, the Commission finds the Settlement recommending PG&E to use self-insurance for wildfire claims to be a reasonable alternative."[49]

- *SCE*—Similar to PG&E, in CPUC D.23-05-013,[50] SCE was authorized to self-insure toward covering wildfire liability up to $1 billion annually for the

[46] See Exhibit PAC/505.
[47] PG&E Decision, at 6. The PG&E Decision additionally recognized that "[g]iven the significant difference in price for wildfire and non-wildfire liability insurance, PG&E now purchases liability coverage for wildfire claims separate from non-wildfire liability insurance" (PG&E Decision at page 4).
[48] PG&E Decision, at 2.
[49] Id., at 15.
[50] *See* A.19-08-013, D.23-05-013 (May 19, 2023) (the SCE Decision), approving the Settlement between SCE, The Utility Reform Network, and the Public Advocates Office at the CPUC (the SCE Settlement).

"Program Period": July 2023–December 2028,[51] again by setting aside funds potentially approaching recent levels of commercial wildfire insurance costs.

In a "worst case" scenario assuming wildfire liability claims of $1 billion in each year of the Program Period, 74 percent of realized costs would be recovered via SCE's Risk Management Balancing Account (RMBA)[52] not subject to reimbursement tied to the outcomes of "reasonableness reviews".[53] In such a "worst case" scenario, most of the 26 percent portion remaining uncollected the end of the 2023 GRC Period could be recovered via a Tier 2 Advice Letter Filing[54], with 1.25 percent paid by a shareholder deductible (2.5 percent on amounts above the $500 million of annual claims). Importantly, per the agreed Settlement formulas, the portion of claims recoverable via the RMBA could be increased significantly under a less adverse scenario. For example, were realized losses over the Program Period limited to $400 million per year—per Appendix B, Example 2 of the SCE Settlement—claims recoverable via the RMBA would grow to 85 percent.

In support of the settlement, the CPUC noted the following:

> "SCE's wildfire insurance costs have increased significantly in recent years. In the 2018 GRC, the Commission authorized $92.4 million for total liability insurance expense (combined wildfire and non-wildfire) for the 2018 test year. In the Track 1 decision, the Commission authorized a 2021 test year forecast of $460.0 million for wildfire liability insurance costs to obtain $1 billion of coverage based on SCE's

[51] Note that 2025 – 2028 would remain subject to revision in the 2025 GRC; *see* SCE Decision page 6.
[52] As further described below, the RMBA was established as part of SCE's 2021 GRC.
[53] SCE Decision, page 8; and SCE Settlement Section 3.4 and Appendix B: "Illustrative Calculation Reflecting the Worst Case Scenario—Cost Recovery for Undercollections at the End of the Program Period".
[54] *See* SCE Settlement Sections 3.3.2, 3.7 and Appendix B. Note that a Tier 2 Advice Letter could be subject to challenge.

> recorded 2020 costs. Due to the volatility and uncertainty of these costs, the Commission authorized SCE to establish the one way RMBA to ensure any overcollection is returned to ratepayers and also authorized SCE to continue to seek rate recovery of any costs in excess of the forecast through its WEMA."[55]

The CPUC articulated further the same reasoning it had used in the PG&E Decisions:

> "Although not guaranteed, we find it likely that customers will receive more cost savings and benefits from self-insurance in 2023 and 2024 compared to commercial insurance. The proposed self-insurance program for SCE is substantially similar to the multi-year 100 percent self-insurance program for wildfire liability approved for Pacific Gas and Electric Company (PG&E) in its 2023 GRC."[56]

- *SDG&E*—In a joint motion filed in October 2023, SDG&E and key stakeholders proposed a settlement embedding a wildfire liability self-insurance option within an authorized test year forecast of $173 million for up to $1 billion in commercial wildfire liability coverage.[57] The self-insurance option would allow SDG&E (with SoCalGas) to set aside $14 million per year toward the first $50 million of potential losses.[58] The SDG&E Settlement remains under consideration by the CPUC.

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[55] SCE Decision, at 9-10. WEMA refers to the Wildfire Expense Memorandum Accounts under which California utilities can record wildfire-related costs pending authority to reflect those costs in rates. See also *Decision Approving Southern California Edison Company's Application for Authorization to Recovery Costs Related to Wildfire Insurance Premiums Recorded in its Wildfire Expense Memorandum Account*, D. 20-09-024 (September 24, 2020).

[56] SCE Decision, at 13.

[57] *See* CPUC A. 22-05-016, Joint Motion of Southern California Gas Company (U 904 G), SGD&E, The Public Advocates Office at the CPUC, The Utility Reform Network, The Utility Consumer's Action Network, and Community Legal Services for Adoption of a Settlement Agreement Resolving All Insurance Issues, filed Oct. 24, 2023, (the SDG&E Settlement).

[58] SDG&E Settlement, at 11.

Q. Please describe the other Regional Precedents.

A. Other noteworthy precedents include wildfire insurance settlements recently achieved by Avista Corporation and Idaho Power.

- *Avista*: In Final Order 10/04,[59] the WUTC approved a settlement authorizing Avista to establish an Insurance Expense Balancing Account for 2023 and 2024 with a step-up in baseline authority of approximately $5.3 million. The WUTC noted the following:

> "[W]e find that Avista has demonstrated unprecedented increases and volatility in its insurance costs. We agree that Avista has shown the insurance expense increases in recent years are "extraordinary" and "volatile" and caused an under-recovery of approximately $5.3 million in 2022. We also find that Avista has demonstrated that it has taken and is taking appropriate steps to try to control these costs, but has shown unprecedented recent increases in insurance that are largely out of its control."[60]

- *Idaho Power*—The IPUC has allowed Idaho Power to defer incremental costs associated with its insurance premiums. The IPUC approved this deferred treatment in 2021, stating the following:

> "We agree with the Company that customers should benefit from adequate insurance coverage. Insurance protects the Company and its customers from unforeseen wildfire-related costs which have caused utility bankruptcy in recent years. While the increased insurance premiums, including the "wildfire load," represent additional costs, the alternative is not prudent or wise. We believe the Company's proactive investment will provide benefits to customers should the Company ever face significant wildfire liability. We find it reasonable to allow the Company to defer its Idaho jurisdictional share of incremental wildfire insurance costs above 2019 levels."[61]

[59] WUTC Docket Nos. UE-220053, UG-220054, UE-210854 (cons.), Final Order 10/04 (Dec. 12, 2022).
[60] *Id.,* at 50.
[61] IPUC Case No. IPC-E-21-02, Order No. 35077 at 8 (June 17, 2021).

Idaho Power and interveners proposed a settlement in Idaho Power's 2023 GRC to continue this deferred treatment. The IPUC approved the settlement.[62]

Q. What are the implications of these precedents for PacifiCorp's filing?

A. The Regional Precedents have the following implications for PacifiCorp's filing:

- Perhaps most importantly, they demonstrate strongly that PacifiCorp is not unique in facing the dramatic and pressing challenge of increasing and more volatile wildfire insurance costs.
- PacifiCorp's utility peers and their regulators recognize wildfire risk—and hence associated insurance costs—as an exogenous risk.
- Regulatory cost recovery mechanisms need to evolve to deal with the pace and scale of this problem. In this regard, regulators have recently entered into settlements with the California IOUs, Avista, and Idaho Power that both defer increased insurance costs, but, in some cases pre-authorize the contingent commitment of funds for self-insurance (based on claims actually realized).
- If recent wildfire liability conditions and regulatory treatments can be described as a "new normal," it is not clear that this state of affairs can be considered stable or predictable. The uncertainty is underscored by the recognition in approved settlements that current conditions are "volatile" and the contingent nature of the California settlements, which are designed to accommodate a wide range of potential wildfire liability outcomes.

[62] IPUC Case No. IPC-E-23-11, Order No. 36042 at 10 (Dec. 28, 2023).

- To the degree that PacifiCorp encounters dysfunctional commercial insurance markets similar to what the California IOUs have faced in recent years, there is no reason that PacifiCorp should not similarly avail itself the benefits of self-insurance in some form.

B. <u>Protection From Extreme Events</u>

Q. What are potential consequences of utility exposure to extreme wildfire claims?

A. As noted above, the "new normal" has included not just uncertainty about increased insurance costs but also the increased likelihood that wildfire liability costs may rarely but very significantly exceed available levels of coverage at any price, possibly reaching several billion dollars. Only a very small number of fires grow to such levels of conflagration, but climate change and more residences and other properties being in the WUI zone of high risk have made the possibility of worst-case scenarios very grim indeed. Claims to date have materially eroded affected utilities' financial resiliency, and in the case of PG&E, led to bankruptcy in 2019. I understand these huge risks are virtually uninsurable in commercial markets, or at least not at any reasonable price, so they need creative utility-based mechanisms for solutions.

Q. How has the risk of extreme wildfire claims been handled in other jurisdictions?

A. Responding to the urgent threat posed by major wildfires in 2017, 2018, and after, the State of California has established mechanisms to protect utilities from associated financial claims. The goals include maintaining financial stability for utilities in support of their obligation to reliably serve customers.

In August 2018, the California state legislature passed a bill to address the cost allocation relating to the 2017 wildfires.[63] While I am not an attorney, my understanding is that Senate Bill 901 expanded various fire prevention and mitigation efforts by several state agencies, and it clarified the CPUC's reasonableness review of utility activities and costs regarding fire mitigation. Importantly, the bill created a framework for socializing wildfire-related costs in 2017 and in future years through a securitized utility financing mechanism. For 2017 specifically, the bill mandated that the CPUC take into account "the electrical corporation's financial status" by determining "the maximum amount the corporation can pay without harming ratepayers or materially impacting its ability to provide adequate and safe service."[64] The bill thus established a mechanism for PG&E to recover costs for 2017 wildfires that would otherwise be disallowed, at least beyond the point to where the disallowance would threaten the utility's financial viability or its ability to provide utility service.[65]

Following PG&E's bankruptcy filing in 2019, the California state legislature passed AB 1054 to further address utility wildfire risk by, among other things, establishing an insurance-like Wildfire Fund (the "California Wildfire Fund"). The legislative language in AB 1054 observed that "[t]he establishment of a wildfire fund supports the credit worthiness of electrical corporations, and provides a mechanism to

[63] California Senate Bill 901 (Wildfires), Legislative Counsel's Digest, published September 8, 2018, https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201720180SB901.
[64] Section 27 of Senate Bill 901.
[65] This concept was further developed by the CPUC in its Order Instituting Rulemaking to Implement Public Utilities Code Section 451.2 Regarding Criteria and Methodology for Wildfire Cost Recovery Pursuant to Senate Bill 901 (2018), July 8, 2019.

attract capital for investment in safe, clean, and reliable power for California at a reasonable cost to ratepayers."[66]

The California Wildfire Fund provided $21 billion of claim-paying coverage to California IOUs in the event of wildfire damages exceeding $1 billion (assumed to approximate the level of commercial insurance available to each of the California IOUs). Utility shareholders and customers both contributed to the fund in equal measure.

It is my understanding that AB 1054 established standards by which the CPUC could determine whether a utility had acted prudently and was therefore eligible to recover wildfire costs through the Fund (or, if the Fund had been exhausted, potentially through electric rates). Prudent conduct in connection with a wildfire event was broadly defined as that consistent with actions that a reasonable utility would have undertaken under similar circumstances, at the relevant point in time, and based on the information available at that time. In due course prudent utility conduct was more specifically codified in the form of specific wildfire mitigation programs and protocols needed to obtain a "safety certification" which formed the main criterion for access to the Fund. Importantly, as part of qualifying for a safety certification, a utility's implementation of its wildfire mitigation plan "is evaluated based on actions taken by a utility, not the outcome of those actions."[67]

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[66] AB 1054, Section 1(a)(5).
[67] *See* Safety Certification FAQ | Office of Energy Infrastructure Safety, https://energysafety.ca.gov/what-we-do/electrical-infrastructure-safety/wildfire-mitigation-and-safety/safety-certifications/safety-certification-faqs/.

Q. Why should this risk be, at least in part, the responsibility of utility customers?

A. As noted above in Section IV, wildfire mitigation cannot reasonably be expected to eliminate all risks. Additionally, for regulated utilities, the necessary judgment calls relating to system hardening and/or operating protocols do not fall within the sole discretion of management. Mitigation spend and operating protocols must be approved by regulators on behalf of customers. This feature of the regulatory compact amounts, at minimum, to an implicit recognition by regulators that agreed mitigation efforts are optimized from a cost/benefit perspective, and therefore prudent.

Meanwhile, negligence standards brought to bear in wildfire damage claims against utilities may not be aligned with the trade-offs necessarily embedded in wildfire mitigation plans. The clearest example of this is the doctrine of "inverse condemnation" applicable in California, which imposes strict liability on the utility without reference to regulatory standards of prudent management. Negligence standards in other jurisdictions may be interpreted to embed inverse condemnation, or for different reasons do not reflect or proxy for feasible wildfire mitigation plans.[68] Neither judges nor juries can be expected to evaluate the technical intricacies of such plans.

Instead, it logically falls to utilities, to choose, in conjunction with customers and regulators, a level of mitigation that is balanced and acceptable. The process is one of negotiation as well as analysis. Key trade-offs must be evaluated between factors including fire mitigation, service quality and reliability, rate increases, and

[68] Notably, the California Wildfire Fund is intended as financial relief from findings of liability, based on prudent utility management. *See* Safety Certification FAQ | Office of Energy Infrastructure Safety, https://energysafety.ca.gov/what-we-do/electrical-infrastructure-safety/wildfire-mitigation-and-safety/safety-certifications/safety-certification-faqs/.

potential future exposure. As noted above, the consensus solution is likely to stop short of attempting to solve the whole problem rapidly or even fully.

As a natural consequence of these processes, there will be residual risk—elected jointly by the stakeholders. In this circumstance, one in which near-term wildfire mitigation spending and associated rate increases are balanced with competing imperatives, there must be provision for recovering residual exposure should it be incurred.

Q. What is the responsibility of the utility?

A. The *quid pro quo* for such contingent cost recovery, of course, is that utility managers diligently pursue a well-defined wildfire mitigation plan accepted by customers and regulators. This principle was established in forming the California Wildfire Fund, with the following key components:

- Utility access to the insurance function of the California Wildfire Fund is contingent on maintaining a safety certification giving evidence of compliance with an approved wildfire mitigation plan.
- Such compliance is to be evaluated based on agreed mitigation efforts—not wildfire outcomes—in recognition of the challenges facing wildfire mitigation and the regulatory process in forming a consensus wildfire mitigation plan.
- Adherence to mitigation plan should be deemed proof of prudence hence cost recovery. That is, absent negligence, regulators should evaluate utilities on the quality of their inputs to the fire prevention problem, not on the outputs of how many fires happen, how much they cost, or even whether a piece of

utility equipment was involved (except insofar as that is a basis for revising future mitigation).

Q. How does PacifiCorp's proposal to address extreme risk meet these criteria?

A. PacifiCorp's proposal to establish a Catastrophic Fire Fund remains in development via the stakeholder workshop process. I understand that the details of the Catastrophic Fire Fund proposal are intended to reflect the principles enumerated above as they take further shape.

VI. CONCLUSION

Q. Please summarize your principal conclusions.

A. My principal conclusions can be summarized as follows:

- PacifiCorp is facing an exogenous, largely climate-induced phenomenon in increased wildfire risk.
- With wildfire risks mounting, the cost of wildfire liability insurance is increasing dramatically.
- Similarly positioned utilities have crafted workable solutions for those costs that recognize wildfire insurance as a legitimate cost of service in recent rate-case proceedings.
- To the degree that PacifiCorp encounters dysfunctional commercial insurance markets similar to what the California IOUs have faced in recent years, there is no reason that PacifiCorp should not similarly avail itself the benefits of self-insurance in some form.
- To the degree ongoing analysis indicates that PacifiCorp faces material and increasing likelihood of catastrophic exposure to unprecedented levels of

extreme wildfire loss claims, PacifiCorp is proposing a new Catastrophic Fire Fund to provide liquidity and maintain longer term financial stability.

- Subject to compliance with reasonable mitigation standards, extreme wildfire loss claims (if they occur) should be viewed as costs of utility service recoverable from customers (just as insurance premia normally are).
- Thus, some form of agreed, socialized cost recovery for these adverse possible situations should be developed before they arise.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 433
Exhibit PAC/501
Witness: Robert S. Mudge

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Robert S. Mudge

Statement of Qualifications

February 2024

Robert Mudge

Principal

Washington, D.C. | +1.202.955.5050 | Robert. Mudge@brattle.com

Mr. Robert Mudge is an expert in corporate and project finance matters in the energy industry. He has advised energy clients on issues relating to asset valuation, credit requirements and financial viability in the context of utility regulatory processes and disputes, litigation, international arbitration, and mergers and acquisitions.

Mr. Mudge has provided expert testimony in diverse forums on matters with a bearing on financial feasibility and/or impact, including the Federal Energy Regulatory Commission, public utility commissions in Massachusetts, Missouri, and Alberta, as well as the Massachusetts Superior Court, the Maine Department of Environmental Protection, and the American Arbitration Association. He has testified or submitted expert reports on other matters in Alaska, California, Florida, Illinois, Kentucky, Michigan, North Carolina, the United States Tax Court, and the International Centre for Settlement of Investment Disputes.

In his previous work as an investment banker, Mr. Mudge played a central role in developing financeable contract structures for large public/private infrastructure projects, utility mergers and acquisitions, bankruptcy restructuring, and numerous power project financings. He has also served on the advisory board of a start-up venture focused on the acquisition, development, and operation of renewable fuel generation projects. Mr. Mudge served as Brattle's COO and Treasurer from 2014 to March 2017.

AREAS OF EXPERTISE

- Electric Power
- Financial Institutions
- Regulatory Finance and Accounting
- Utility Regulatory Practice and Ratemaking
- Valuation
- Energy Litigation and Arbitration

EDUCATION

Mr. Mudge received an M.B.A. in Finance and Economics from the University of Chicago, Graduate School of Business, Chicago, IL, and a B.A. (*cum laude*) from Harvard College, Cambridge Massachusetts.

ASSOCIATIONS

Energy Bar Association, Chair - Finance and Transactions Committee, 2016-2017.

EXPERIENCE

- **For the Coalition for Green Capital,** a policy NGO, Mr. Mudge produced a detailed financial model to illustrate the levering of private-sector clean energy investment via a proposed National Green Bank ("NGB", to be capitalized by funding authorized under the Inflation Reduction Act of 2022). The model depicted combining public and private resources to fund a diverse portfolio of debt and equity investments on concessionary terms, as well as grants.
- **For the Shady Hills Energy Center,** a wholly owned indirect subsidiary of General Electric Credit Corporation of Tennessee, Inc., Mr. Mudge submitted testimony before the District Court for the Middle District of Florida addressing custom and practice in project financing. (See also Testimony below).
- **For NTE Energy**, Mr. Mudge submitted testimony before the District Court for the Western District of North Carolina providing a valuation of the Reidsville Energy Center. (See also Testimony below).
- **For CorEnergy Infrastructure Trust, Inc.**, Mr. Mudge sponsored testimony before the California Public Utilties Commission supporting the viability of regulated infrastructure owned by an entity organized as a Real Estate Investment Trust ("REIT"). (See also Testimony below).
- **In connection with a securities fraud case in District Court**, Mr. Mudge assessed the viability and valuation of a portfolio of non-utility power plants in early development in the U.S. and Canada. In particular, Mr. Mudge developed a framework for treating pro forma project cash flow forecasts to account for the development-period risks of completing feasibility analyses, securing sites, obtaining permits, finalizing contracts, and attracting project debt financing. The case settled favorably for client in 2021.
- **For Pacific Gas and Electric Company,** Mr. Mudge led the Brattle team providing analytic support to obtain regulatory approvals in connection PG&E's emergence from bankruptcy in 2020, with particular focus on PG&E's path back to investment grade status.
- **For Pacific Gas and Electric Company,** Mr. Mudge sponsored testimony before the Federal Energy Regulatory Commission asserting the continued applicability of prior reports analyzing residual PG&E exposure to financial risk from wildfire claims. (See also Testimony below.)
- **For Siemens Gamesa Renewable Energy (SGRE),** Mr. Mudge assisted in the preparation of testimony sponsored by a wind energy executive in a dispute between SGRE and one of its suppliers. (See also Testimony below.)

- **For Southern California Edison and Pacific Gas and Electric Company,** Mr. Mudge co-sponsored an expert report and supplemental testimony before the California Public Utilities Commission analyzing residual utility exposure to financial risk from wildfire claims in context of recent California legislation. (See also Testimony, below.)
- **For shareholders in Sun Edison,** Mr. Mudge prepared an **e**xpert report assessing adequacy of disclosure to shareholders by SunEdison management in 2015. (See also Testimony, below.)
- **For Nicor Gas**, Mr. Mudge prepared a cost of equity analysis. (See also Testimony, below.)
- **For an international engineering, procurement, and construction (EPC) contractor,** Mr. Mudge co-sponsored a confidential expert report estimating the fair market value of a power plant at a future date based on projected cash flows in combination with other assets and foreseeable liabilities. (See also Testimony, below.)
- **For the Government of Grenada in ICSID arbitration,** Mr. Mudge developed a discounted cash flow analysis to value power assets to be repurchased by the government from the Claimants, and demonstrated that the "formula" price originally agreed by the parties was inconsistent with any standard approach to determining fair market value. (See also Testimony, below.)
- **For Goldman Sachs,** Mr. Mudge assessed financial projections to support multiple bond issues for the Red Rock biofuels project.
- **For Duke Energy Carolinas LLC and Duke Energy Progress LLC,** Mr. Mudge provided analytic support and interrogatories in connection with Duke regulatory negotiations with solar developers.
- **For Sharyland Utilities L.P. rate case,** Mr. Mudge provided analytic support and interrogatories in connection with intervener assertions that Sharyland's REIT structure exposed customers to incremental cost and risk.
- **For Anchorage Municipal Light & Power (ML&P),** Mr. Mudge developed a rate stabilization plan in connection with an investment that increased ML&P's net plant by more than 70%. The plan included design of a regulatory asset for recovery over a 35-year period. (See also Testimony, below.)
- **For St Bernard Parish, LA**, Brattle conducted historical reconstructions of peak electricity and gas demand over multiple decades (for which records did not exist).
- **For the Massachusetts Water Resources Authority (MWRA),** in testimony before the Massachusetts Department of Public Utilities (DPU), Mr. Mudge assessed the historic and current cost of capital for a dedicated, project-financed electric transmission line owned by a subsidiary of NSTAR Electric providing delivery service to MWRA's Deer Island water treatment facility. (See also Testimony, below.)

- **For First Solar, Xcel Energy, and the Edison Electric Institute**, Mr. Mudge developed a financial model to calculate and compare revenue requirements for utility-and residential-scale solar PV panels in the Xcel Energy Colorado system. The model reflected assumptions for technical parameters, capital and operating costs, economic assumptions such as inflation, capital sourcing (debt, equity, and tax equity), and associated costs, as well as other incentives, as applicable.
- **For an investor owned utility company in a regulatory proceeding**, Mr. Mudge assessed the rationale for and impact of preferential "load-retention" tariff requested by major industrial customer, including an analysis of customer liquidity and financing. (See also Testimony, below.)
- **For ISO-New England (ISO-NE)**, Mr. Mudge assessed the implications of ISO-NE's proposal to integrate stronger performance incentives—referred to as "Pay For Performance"—with the existing Forward Capacity Market for the feasibility of debt and equity financing of new generation entering the ISO NE market. (See also Testimony, below.)
- **For Enel Green Power S.p.A. (Enel)**, Mr. Mudge assessed the contingent value of Enel's ownership stake in LaGeo S.A. de C.V. (LaGeo), a geothermal development and operating company with a portfolio of assets in El Salvador. (See also Testimony, below.)
- **For an international investor in electric utility assets**, Mr. Mudge supported regulatory due diligence regarding the potential acquisition of Cleco Corporation.
- **For an investor owned utility company exploring strategic alternatives**, Mr. Mudge analyzed potential responses to distributed renewable energy projects and associated adverse effects on load growth (including potential utility ownership of distributed generation and inclusion in rate base).
- **For the New York Power Authority (NYPA)**, in connection with NYPA's role in developing contingency plans for the potential retirement of the Indian Point Energy Center, Mr. Mudge assisted in due diligence on the feasibility of respondents' proposals to an RFP for replacement capacity. He assessed the feasibility of proposed projects and the sponsors' ability to complete them by a stipulated deadline. Evaluation included the assessment of site control and permitting; technical and contractual feasibility; project financial plans and sponsor capabilities; and community impact.
- **For the Connecticut Clean Energy Finance and Investment Authority/ Coalition for Green Capital**, Mr. Mudge constructed a financial model to highlight incremental benefits of potential low-cost "Green Bank" funding for solar photovoltaic projects. To be realistic about capital structure and debt carrying capacity, tax equity cash flow and tax mechanisms were explicitly developed assuming a partnership flip structure.
- **For an independent power developer seeking to sell power to an investor owned utility,** Mr. Mudge assessed the impact of the imputed debt treatment likely to be applied by rating agencies with respect to a power purchase agreement. (See also Testimony, below.)

- **For an unsecured creditor in the bankruptcy of TerreStar Networks Inc.,** Mr. Mudge assessed potential payouts based on contingencies including the outcome of litigation concerning the validity of secured creditor liens and proposed early payouts to secured creditors.
- **For TransCanada Corporation**, in testimony before the Alberta Utilities Commission (AUC), Mr. Mudge assessed bid evaluation protocols proposed by the Alberta Electric System Operator (AESO) in connection with the AESO's Competitive Process for Critical Transmission Infrastructure (CTI). (See also Testimony, below.)
- **For the Department of the Treasury,** Mr. Mudge assessed the structure and financing of a $10 billion + cross border utility merger. The assignment included comparison of affiliate debt financing with comparable "arm's length" financing visible in the marketplace in the relevant timeframe. (See also Testimony, below.)
- **For a special litigation committee** established in connection with a shareholder lawsuit brought against a developer of renewable energy projects, Mr. Mudge assessed debt and equity financing options that could have been brought to bear to optimize shareholder returns. (See also Testimony, below.)
- **For an electric cooperative,** Mr. Mudge managed financial analysis in connection with transformative restructuring of $1.2 billion generation and transmission electric cooperative, reporting to the CEO, CFO, and transaction counsel. The restructuring included termination of complex power supply arrangements, lease unwind, acquisition of generating assets, acquisition of new customers, related financing arrangements and securing an investment grade credit rating. The restructuring also replaced a previously existing mortgage with the Rural Utilities Service with a new senior secured indenture. (See also Testimony, below.)
- **In the formation of a renewable energy debt fund,** Mr. Mudge advised the managers on portfolio structuring, credit analysis and related protocols, and implementation.
- **In the process of a power plant sale,** Mr. Mudge managed a multi-disciplinary team in providing market analysis and financial modeling in support of a successful bid for a $300 million generating plant asset.
- **For an LNG developer,** Mr. Mudge provided analysis and expert testimony before the state Board of Environmental Protection on project financial capacity to support environmental permitting and compliance. (See also Testimony, below.)
- **Mr. Mudge completed a financeability analysis** relating to $2.5 billion capital project proposed to operate under long-term contract with the US Department of Energy (DOE).
- **Mr. Mudge provided analysis and expert testimony before arbitration panel** relating to costs incurred in delayed startup of a 1,000 MW merchant power plant. (See also Testimony, below.)

- **For project counsel,** Mr. Mudge developed a working finance plan and analysis to optimize construction costs for a $1.2 billion new-build power project proposed to be owned by a consortium including IOUs, municipalities, and an electric cooperative.
- **Mr. Mudge evaluated diverse financing options for the Tennessee Valley Authority (TVA)** relating to nuclear repowering initiatives and investment in emissions control equipment, reporting to the CFO.
- **As a member of the advisory board for a start-up venture, Advanced Renewables, LLC,** Mr. Mudge advised on acquisition, development, and operation of renewable-fuel generation projects, consultation on structuring, acquisition prospects, and capitalization.
- **For a major contractor to US Department of Energy (DOE),** Mr. Mudge provided assistance on project finance structuring and sourcing for privatized environmental projects, including creation of financeable contract structure and assembly of top-tier financing syndicate.
- **For US utility and independent energy clients,** Mr. Mudge identified and implemented asset and corporate acquisitions, including advice on valuation, due diligence, approach, and negotiations and assessment of key drivers.
- **With a major multi-lateral agency,** Mr. Mudge participated in the structuring of a debt and equity investment fund for emerging markets power projects.
- **As a project finance banker,** Mr. Mudge conducted numerous transactions domestically and abroad in electric power generation, oil and gas pipelines, and other infrastructure.

REPORTS AND PRESENTATIONS

- "Clean Energy and Sustainability Accelerator: Opportunities for Long-Term Deployment", Prepared for the Coalition for Green Capital (with F. Graves, R. Lueken, and T. Counts), January 14, 2021.
- "FERC's Recent Ruling(s) on PURPA: Competitive Procurement Option" Panelist, Electric Utility Consultants, Inc.'s (EUCI) Online PURPA Conference, December 15, 2020.
- "Impacts and Implications of COVID-19 for the Energy Industry: Assessment through Mid-October", Published by The Brattle Group, Inc. (with F. Graves and J. Figueroa), November 2, 2020.
- "COVID-19 and Utility Financial Impact", Published by The Brattle Group, Inc., September 30, 2020.
- "Supplemental Report on Wildfire Risk and AB 1054," filed to accompany Cost of Capital Applications 19-04-014 and 19-04-015 on behalf of Southern California Edison and Pacific Gas and Electric Company, September 5, 2019.

- "California Megafires: Approaches for Risk Compensation and Financial Resiliency Against Extreme Events," filed to accompany SCE's TO2019A transmission owner tariff filing before FERC in Docket No. EL19-__-000 (with F. Graves), April 2019.
- "California Megafires: Approaches for Risk Compensation and Financial Resiliency Against Extreme Events," filed to accompany PG&E's "TO20" transmission cost of capital testimony before FERC in Docket No. EL19-13-000 (with F. Graves and M. Geronimo), October 2018.
- "Resetting FERC ROE Policy: A Window of Opportunity," Published by The Brattle Group, Inc., (with A. Sheilendranath and F. Graves), May 2018.
- "New Tax Law and its Impact on Rates," Panelist, Energy Bar Association Annual Meeting, May 2018.
- "The Evolving Energy Landscape: Transformation of the Power Market," Featured Speaker, POWER Engineers Symposium, April 2018.
- "History & Legal Framework of PURPA," Panelist, Electric Utility Consultants, Inc.'s (EUCI) Public Utilities Regulatory Policies Act 101 conference, March 2018.
- "Rising Tide of Next Generation U.S. P3s – and How to Sustain It," Study published by The Brattle Group, Inc., (with E. Buckberg and H. Sheffield), February 27, 2018.
- "New Technologies and Old Issues under PURPA," *Norton Rose Fulbright Project Finance Newswire*, (with M. Celebi, M. Chupka, and P. Cahill), February 20, 2018.
- "Six Implications of the New Tax Law for Regulated Utilities," Analysis published by The Brattle Group, Inc., (with B. Villadsen and M. Tolleth), January 2018.
- "The History of PURPA and the Evolving PURPA/QF Landscape," Panelist, Electric Utility Consultants, Inc. (EUCI) Public Utility Regulatory Policies Act of 1978 Litigation and Qualifying Facilities Symposium, November 2017.
- "Risk and Return for Regulated Utilities", moderated panel discussion accompanying book release during NARUC Summer Policy Summit, July 18, 2017.
- "High Market-to-Book Ratios Among Regulated Utilities—A Review of Plausible Drivers", presentation to the Center for Research in Regulated Industries Western Conference, June 29, 2017.
- "Ongoing Climate Imperative," moderated Energy Bar Association panel discussion. November 10, 2016.
- "Energy System Optimization: The Role of Decentralization," Panelist, Vermont Law School Alumni in Energy's Third Annual Energy Symposium. October 6, 2016.
- "Powering America: An Analysis of Policy and Market Developments Impacting the US Power Sector", moderated panel at American Bar Association Business Law Section Annual Meeting (with M. Celebi, Susan Nickey of Hannon Armstrong, and Elias Hinckley of Sullivan & Worcester). September 10, 2016.

- "Scaling the Economics of Solar PV," presentation to the Wisconsin Public Utility Institute. February 25, 2016.
- "Comparative Generation Costs of Utility-Scale and Residential-Scale PV in Xcel Energy Colorado's Service Area," report prepared for First Solar, with support from Xcel Energy and EEI (with P. Fox-Penner, B. Tsuchida, S. Sergici, W. Gorman, and J. Schoene). July 2015.
- Distributed solar payback analysis in support of Reply Comments by Southern California Edison Company in connection with California Public Service Commission Rulemaking 12-11-005: Order Instituting Rulemaking Regarding Policies, Procedures and Rules for California Solar Initiative, the Self-Generation Incentive Program and Other Distributed Generation Issues (with M. Vilbert and J. Wharton). December 23, 2013.
- "Overview of Rooftop Solar PV 'Green Bank' Financing Model," sponsored by Connecticut Clean Energy Finance and Investment Authority and the Coalition for Green Capital. January 17, 2013.
- "Can PURPA Legacy Help Utilities Manage DG Concerns?" presented at the Energy Bar Association 2013 mid-year meeting and conference. October 24, 2013.
- "ERCOT Investment Incentives and Resource Adequacy," report prepared for the Electric Reliability Council of Texas (with S. Newell, K. Spees, J. Pfeifenberger, M. DeLucia, and R. Carlton). June 1, 2012.
- "MLPs for Renewables: Complement or Substitute for Tax Credits?", presented at the EUCI Conference on Renewable Energy M&A Transactions, San Diego, CA, December 6, 2011.
- "Optimizing Gas for Flexible Power," presented at the Utility Scale Flexible Power Summit, Denver, CO, September 28, 2011.

TESTIMONY

"Expert Report of Robert S. Mudge on Behalf of Shady Hills Energy Center, LLC" in matter of Shady Hills Energy Center, LLC, Plaintiff, v. Seminole Electric Cooperative, Inc., Defendant, Counter-Plaintiff, and Third-Party Plaintiff, v. Shady Hills Energy Center, LLC, Counter-Defendant, v. EFS Shady Hills Expansion Holdings, LLC, EFS Shady Hills, LLC, General Electric Credit Corporation of Tennessee, Inc., GE Capital US Holdings, Inc., GE Capital Global Holdings, LLC, Third-Party Defendants. *District Court for the Middle District of Florida Tampa Division, Case No. 8:20-cv-00081-WFJ-JSS.* February 28, 2022. Deposition taken May 20, 2022.

"Expert Report of Robert S. Mudge on Behalf of NTE Energy" in matter of Duke Energy Carolinas, LLC, Plaintiffs, v. NTE Carolinas II, LLC, NTE Carolinas II Holdings, LLC, NTE Energy LLC, NTE Southeast Electric Company, LLC, NTE Energy Services Co., LLC, and Castillo Investment Holdings II, LLC, Defendants/Counterclaimants-Plaintiffs v. Duke Energy Progress, LLC, and Duke Energy Corporation.

District Court for the Western District of North Carolina Charlotte Division, Civil Action No. 3:19-cv-515. January 14, 2022. Deposition taken March 25, 2022.

California Public Utility Commission, Proceeding A2102013. Testimony in support of the Application of Mr. John D. Grier for Authority to Sell and Transfer and CorEnergy Infrastructure Trust, Inc. to Acquire Control of Crimson California Pipeline, L.P. (PLC-26) and San Pablo Bay Pipeline Company, LLC (PLC-29) Pursuant to Public Utilities Code Section 854. November 23, 2021.

Federal Energy Regulatory Commission, Docket No. ER20-2878-000. Testimony in support of Pacific Gas and Electric Company's Proposed Rate and Non-Rate Changes to the Wholesale Distribution Tariff, FERC Electric Tariff Volume No. 4 and Related Service Agreements for Wholesale Distribution Service. September 15, 2020.

"Expert Report of Jeffrey D. Schlichting in the Matter of Arcosa Wind Towers Inc. v. Siemens Gamesa Renewable Energy, Inc. and Siemens Energy, Inc." *District Court of Dallas County, Texas, Cause No. DC-19-13334.* Assisted in preparation of report. August 3, 2020.

California Public Utility Commission, Cost of Capital Applications 19-04-014 and 19-04-015 on behalf of Southern California Edison and Pacific Gas and Electric Company. Expert report and supplemental testimony analyzing residual utility exposure to financial risk from wildfire claims in context of AB 1054. August 1, 2019 and before the Commission, September 5, 2019.

International Centre for Settlement of Investment Disputes, Case No. ARB/17/13. Confidential expert report assessing the value of Grenada Electricity Services Company Limited, March 29, 2019 and before the Tribunal, June 20, 2019.

SunEdison, Inc., Securities Litigation, 1:16-md-2742 (PKC) (AJP) (S.D.N.Y.); *Horowitz v. SunEdison, Inc.*, 1:16-cv-7917 (PKC) SUNE. Expert report assessing adequacy of disclosure to shareholders by SunEdison management in 2015. March 1, 2019.

American Arbitration Association, International Centre for Dispute Resolution. Confidential expert report for an international engineering, procurement, and construction (EPC) contractor to estimate the fair market value of a power plant at a future date based on projected cash flows in combination with other assets and foreseeable liabilities. November 27, 2018.

Illinois Commerce Commission, Northern Illinois Gas Company d/b/a Nicor Gas Company proposed general increase in gas rates. Direct testimony on behalf of Nicor Gas, supporting an increase in gas rates. November 9, 2018.

International Centre for Settlement of Investment Disputes. Confidential expert report assessing the value of an electric utility. June 29, 2018.

Regulatory Commission of Alaska, In the Matter of the Tariff Revisions, Designated as TA357-121, filed by the Municipality of Anchorage d/b/a Municipal Light and Power Department. Direct testimony on behalf of Anchorage Municipal Light & Power (ML&P), supporting a rate stabilization plan to reallocate the recovery of investment that increased net plant by more than 70%. The plan included design of a regulatory asset for recovery over a 35-year period. December 30, 2016.

Commonwealth of Massachusetts Department of Public Utilities, Case D.P.U. 15-157. Direct testimony on behalf of the Massachusetts Water Resources Authority (MWRA) in response to the Petition and associated filings of NSTAR in Massachusetts Department of Public Utilities (D.P.U.) 15-157 with respect to appropriate project financing for dedicated electricity delivery facilities for MWRA's Deer Island water treatment facility and NSTAR's proposed tariff. February 9, 2016.

Missouri Public Service Commission, Case No. ER-2014-0258. Rebuttal testimony on behalf of Ameren Missouri in the matter of Noranda Aluminum, Inc.'s request for revisions to Ameren Missouri's Large Transmission Service Tariff to decrease its rate for electric service (as part of a general Ameren rate case). Analysis addressing Noranda's claim of imminent liquidity crisis, potential alternative capital sourcing, and Noranda's competitive position in U.S. aluminum industry. January 15, 2015.

International Centre for Settlement of Investment Disputes, Case No. ARB/13/18 (Enel Green Power S.p.A. (Enel) v. Republic of El Salvador). Expert report assessing the contingent value of Enel's ownership stake in LaGeo S.A. de C.V. (LaGeo), a geothermal development and operating company with a portfolio of assets in El Salvador, associated with Enel's rights under a shareholder agreement with the government of El Salvador. December 5, 2014.

Missouri Public Service Commission, Case No. EC-2014-0224. Rebuttal testimony on behalf of Ameren Missouri in the matter of Noranda Aluminum, Inc.'s request for revisions to Ameren Missouri's Large Transmission Service Tariff to decrease its rate for electric service. Analysis addressing Noranda's claim of imminent liquidity crisis, potential alternative capital sourcing, and Noranda's competitive position in U.S. aluminum industry. May 9, 2014.

Federal Energy Regulatory Commission, Docket Nos. ER14-1050. Testimony responding to protests, comments and testimony submitted in ER14-1050 by the New England Power Pool Participants Committee (NEPOOL) and others suggesting that ISO New England's proposal to integrate stronger performance incentives—referred to as "Pay For Performance"—with the existing Forward Capacity Market would materially hinder debt and equity financing of new generation entering the ISO-NE market. March 3, 2014.

Robert Mudge

Michigan Public Service Commission, Case No. U-17429. Direct testimony in the matter of the application of Consumers Energy Company for approval of a Certificate of Necessity for the Thetford Generating Plant and for related accounting and ratemaking authorizations. Assessment of imputed debt impact and accompanying financial risks asserted by Consumers in connection with power purchase agreements. October 29, 2013.

Alberta Utilities Commission, Application No. 1607670, Proceeding ID 1449, Alberta Electric System Operator Competitive Process Application. Written testimony assessing AESO proposed evaluation methodology for the financing component of proponents' RFP bids in connection with the Competitive Process for Critical Transmission Infrastructure (CTI). June 1, 2012.

"N.A. General Partnership v. Commissioner," Expert Report in connection with testimony before the United States Tax Court in the matter of *NA General Partnership & Subsidiaries, Iberdrola Renewables Holdings, Inc. & Subsidiaries, Successor in Interest to NA General Partnership & Subsidiaries,* Docket 525-10. April 8, 2011.

"Assessment of Powerbank Transactions – Commercial Rationale and Consistency with Allocation of 2007 Sale Proceeds," Expert Report in the matter of *Paul Bergeron, on behalf of Ridgewood Electric Power Trust V and Ridgewood Power Growth Trust v. Ridgewood Renewable Power, LLC,* C.A. No. 07-1205 BLS1. October 28, 2010.

Kentucky Public Service Commission, Case No. 2007-00455 on behalf of Big Rivers Electric Corporation, regarding the Applications of Big Rivers Electric Corporation for: (I) Approval of Wholesale Tariff Additions for Big Rivers Electric Corporation, (II) Approval of Transactions, (III) Approval to Issue Evidences of Indebtedness, and (IV) Approval of Amendments to Contracts; and of E.ON U.S., LLC, Western Kentucky Energy Corp., and LG&E Energy Marketing, Inc., for Approval of Transactions. 2007.

Testimony before the Maine Board of Environmental Protection in the matter of *Downeast LNG, Inc. and Downeast Pipeline LLC LNG Terminal and Pipeline, Robbinston, Calais, Baring PLT, Baileyville, and Princeton* L-23432-26-A-N, L-23432-TG-B-N, and A-000960-71-A-N. June 2007.

Testimony before American Arbitration Association Construction Industry Tribunal in the matter of the arbitration between *The Shaw Group/Stone & Webster, Inc. vs. New Harquahala Generating Company, LLC* Case No. 16 110Y00 242 04. 2005 and 2006.

Docket No. UE 433
Exhibit PAC/502
Witness: Robert S. Mudge

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

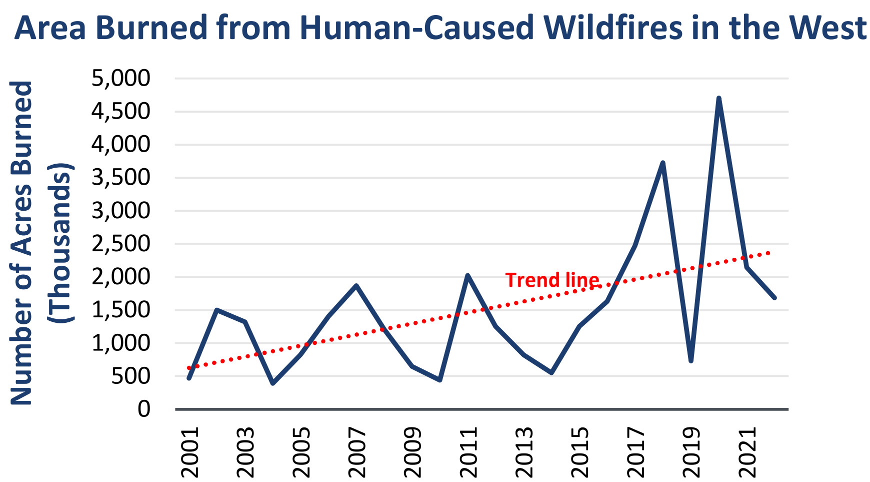
PACIFICORP

Exhibit Accompanying Direct Testimony of Robert S. Mudge

Area Burned from Human Caused Wildfires in the West

February 2024

Area Burned from Human Caused Wildfires in the West



Source: National Interagency Coordination Center, https://www.nifc.gov/fire-information/statistics/human-caused. The west includes the Northwest, California, Northern Rockies, Great Basin, and Southwest regions.

Docket No. UE 433
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BEFORE THE PUBLIC UTILITY COMMISSION

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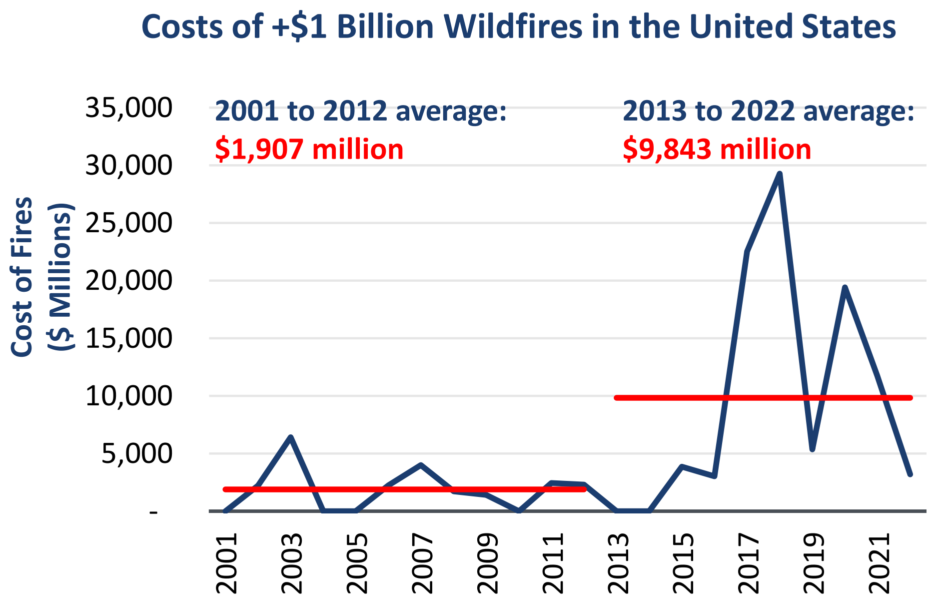
Exhibit Accompanying Direct Testimony of Robert S. Mudge

Costs of +$1 Billion Wildfires in the United States

February 2024

Costs of +$1 Billion Wildfires in the United States



Source: National Oceanic and Atmospheric Administration – National Centers for Environmental Information U.S. Billion-Dollar Weather and Climate Disasters (2023), https://www.ncei.noaa.gov/access/billions/state-summary/US.

Docket No. UE 433
Exhibit PAC/504
Witness: Robert S. Mudge

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Robert S. Mudge

Recent Costs of Wildfire Insurance Faced by Regional Utilities

February 2024

Recent Costs of Wildfire Insurance Faced by Regional Utilities

		Units	Period							
			2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023
PG&E (Wildfire Liability)	[a]									
Costs		$M	43	72	120	385	159	708	707	745
Coverage Limits		$M	931	869	843	1,400	430	868	900	940
Costs/ Coverage		%	5%	8%	14%	28%	37%	82%	79%	79%
Cal. Year O&M Expense (excl. fuel and purchased power)		$M	6,949	7,327	6,383	7,153	8,750	8,707	10,194	9,725
Insurance Cost/ O&M Expense		%	0.6%	1.0%	1.9%	5.4%	1.8%	8.1%	6.9%	7.7%
SCE (Wildfire)	[b]									
Costs		$M				237	400	450	413	357
Coverage Limits		$M				990	1000	870	875	835
Costs/ Coverage		%				24%	40%	52%	47%	43%
Cal. Year O&M Expense (excl. fuel and purchased power)		$M				2,702	2,936	3,523	3,588	4,659
Insurance Cost/ O&M Expense		%				8.8%	13.6%	12.8%	11.5%	7.7%
SDG&E (Wildfire Liability)	[c]									
Costs		$M		80	110	129	183	202	215	221
Coverage Limits		$M		1,500	1,500	1,500	1,500	1,500	1,500	1,500
Costs/ Coverage		%		5%	7%	9%	12%	13%	14%	15%
Cal. Year O&M Expense (excl. fuel and purchased power)		$M		1,048	1,020	1,058	1,181	1,455	1,587	1,677
Insurance Cost/ O&M Expense		%		7.6%	10.8%	12.2%	15.5%	13.9%	13.5%	13.2%
Avista (General Liability)	[d]									
Costs		$M						7	9	14
Coverage Limits		$M						na	na	na
Costs/ Coverage		%						na	na	na
Cal. Year O&M Expense (excl. fuel and purchased power)		$M						360	372	417
Insurance Cost/ O&M Expense		%						1.8%	2.5%	3.3%
Idaho Power (Excess Liability)	[e]									
Costs		$M				7	8	9	11	14
Coverage Limits		$M				na	na	na	na	na
Costs/ Coverage		%				na	na	na	na	na
Cal. Year O&M Expense (excl. fuel and purchased power)		$M				401	392	388	396	437
Insurance Cost/ O&M Expense		%				1.8%	1.9%	2.3%	2.8%	3.3%

[a] A. 21-06-021, CPUC Decision (D.) 23-01-005 at Table 2 (Jan. 17, 2023) , Table 2; PG&E 10K; S&P Capital IQ.

[b] EIX Form 10-K; S&P Capital IQ.

[c] Application of San Diego Gas & Electric Company for Authority, Among Other Things, to Update its Electric and Gas Revenue Requirement and Base Rates Effective on January 1, 2024, A.22-05-016, SDG&E Prepared Direct Testimony of Dennis J. Gaughan (Corporate Center - Insurance), Table DG-18 (years 2021 and 2022 are forecasts) (May 2022).. Application of San Diego Gas & Electric Company, A.19-04-017, Exhibit No. SDG&E-05, Prepared Direct Testimony of John J. Reed and James M. Coyne at 34 (Apr. 2019); S&P Capital IQ.

[d] Avista Corporation v. WUTC, Washington Utilities and Transportation Commission (WUTC), Docket Nos. UE-220053, UG-220054, UE-210854, Rebuttal Testimony of Elizabeth M. Andrews, Table 7 (August 19, 2022); S&P Capital IQ.

[e] In the Matter of the Application of Idaho Power for an Accounting Order Authorizing the Deferral of Incremental Wildfire Mitigation and Insurance Costs, Idaho Public Utilities Commission Case No. IPC-E-21-02, filed Jan. 22, 2021; In the Matter of the Application of Idaho Power for Authority to Increase its Rates and Charges for Electric Service in the State of Idaho and for Associated Regulatory Account Treatment, Idaho Public Utilities Commission (IPUC) Case No. IPC-E-23-11, Motion for Approval of Stipulation and Settlement, October 2023; S&P Capital IQ.

Docket No. UE 433
Exhibit PAC/505
Witness: Robert S. Mudge

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Robert S. Mudge

Recent Wildfire Insurance Cost Recovery Settlements Achieved by Regional Utilities

February 2024

Recent Wildfire Insurance Cost Recovery Settlements Achieved by Regional Utilities

	PG&E		**SCE**		**SDG&E**		**Avista**	**Idaho Power**
Jurisdiction	CPUC		CPUC		CPUC		WUTC	IPUC
Decision/ Settlement	Application 21-06-021: DECISION APPROVING SETTLEMENT REGARDING WILDFIRE LIABILITY INSURANCE COVERAGE		Application 19-08-013: DECISION MODIFYING DECISION 21-08-036 AND ADOPTING AGREEMENT REGARDING WILDFIRE LIABILITY INSURANCE		Application No. 22-05-016: JOINT MOTION FOR ADOPTION OF A SETTLEMENT AGREEMENT RESOLVING ALL INSURANCE ISSUES		Dockets UE-220053, UG-220054, UE-210, Final Order 10/04 Rejecting Tariff Sheets; Granting Petition; Approving and Adopting Full Multiparty Settlement Stipulation Subject to Conditions; Authorizing and Requiring Compliance Filing	Case No. IPC-E-23-11, Motion for Approval of Stipulation and Settlement
Date	Jan-23		May-23		Oct-23		Dec-22	Oct-23
Status	Settlement Approved		Settlement Approved		Settlement Filed		Settlement Approved	Settlement Filed
Applicable Period	2023-2026		2023-2028		2024-2027		2023-2024	2024
Insurance Type	Self		Self		Self Option**	Commercial	Commercial	Commercial
Average Annual Losses ($M):	Worst Case	Recent Exp.	Worst Case	App. B, Ex. 2	Worst Case			
	1,000.0	458.0	1,000.0	400.0	50.0			
Average Annual Loss Allocations ($M):								
Preauthorized Recovery*	718.8	424.8	741.4	338.3	14.0	173.0	8.3	14.5
Shareholder Deductible	50.0	22.9	12.5	0.0				
Undercollection/ (Overcollection)	231.3	10.3	246.1	61.7				
Average Annual Loss Allocations (%):								
Preauthorized Recovery*	71.9%	92.8%	74.1%	84.6%	28.0%			
Shareholder Deductible	5.0%	5.0%	1.3%	0.0%				
Undercollection/ (Overcollection)	23.1%	2.2%	24.6%	15.4%				
Preauthorized Cost/ Target Coverage (%):						17.3%	NA	NA
Preauthorized Cost/ O&M (%)***:	7.4%	4.4%	15.9%	7.3%	0.8%	10.3%	3.3%	3.3%
Cost Deferral Mechanisms	Balancing Account		Balancing Account		Balancing Account		Balancing Account	TBD

*Varies with actual losses for self-insurance

**Embedded within commercial authorization @ $14m per year up to $50m.

*** WA portion for Avista

Docket No. UE 433
Exhibit PAC/600
Witness: Joelle R. Steward

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Joelle R. Steward

February 2024

TABLE OF CONTENTS

I. INTRODUCTION OF WITNESS AND QUALIFICATIONS

Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power (PacifiCorp or 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 summarize your education and business 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 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 appeared as a witness in previous regulatory proceedings?

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

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your direct testimony?

A. I describe two proposals the Company seeks to have approved in this proceeding that will help position the Company to respond to financial risk posed by the increasing frequency and severity of wildfires impacting PacifiCorp's service territories. The proposals complement the Company's ongoing investments in wildfire mitigation throughout its service territory. The new regulatory tools the Company proposes are necessitated by the rapid changes in the insurance market and the wildfire liability outlook for utilities throughout the West. The Company requests the Public Utility Commission of Oregon (Commission) approval of:

- An Insurance Cost Adjustment (ICA) that will recover the costs for excess liability insurance through a separate surcharge. Separating recovery for this expense will enable the Company to annually procure insurance for third-party liability using the most economical combination of commercial insurance and self-insurance through a new Insurance Mechanism that the Company is developing. The Company will seek approval for the Insurance Mechanism through a separate filing but presents the need for and framework of it in this filing to support the approval of the ICA.

- A Catastrophic Fire Fund framework that will facilitate creation of a multi-state risk pool for potential catastrophic events where third-party liabilities are in excess of the Company's insurance coverage.

Additional testimony supporting the need for the Company's proposals is provided by Company witnesses Mariya V. Coleman and Robert S. Mudge.

The Company has presented the Insurance Mechanism and Catastrophic Fire Fund concepts to stakeholders in multi-state workshops that began in September 2023. The Company continues to work with stakeholders to gather feedback on the design and implementation of the Insurance Mechanism and the Catastrophic Fire Fund, and, as discussed in my testimony, will present additional data to the

Commission from analysis aimed at further detailing PacifiCorp's insurance and risk management options.

Q. Why is the Company seeking approval of these proposals in this proceeding?

A. The Company presents its proposals in its general rate case (GRC) for two reasons. First, liability insurance is a category of expense that the Commission has considered a necessary part of the Company's cost of service recovered in retail rates. The Insurance Mechanism will be an innovative vehicle for managing liability insurance expenses as circumstances change with the commercial insurance market, which evidence suggests is becoming strained by coverage demands for wildfires and other extreme weather events around the world. Second, the ICA and Catastrophic Fire Fund involve targeted surcharges that would be incorporated into Oregon rates in this proceeding.

Subsequent to this filing the Company intends to file for approval of the Insurance Mechanism, including liability coverage level, that the ICA will support. The Company's insurance coverage comes up for renewal on August 15 of each year. As discussed in my testimony and further explained in the testimony of Company witness Coleman, there is no doubt that commercial insurance covering wildfire liability will be extremely expensive for the coverage that is available when the Company must make its annual coverage decisions in August 2024. Obtaining reasonable insurance coverage for known wildfire risks will be more feasible if the Company has the Commission's authorization to implement its Insurance Mechanism by that time. To facilitate a path to resolution that will occur in time to impact the Company's insurance renewal decisions in August 2024 and to support the need for the ICA, my testimony outlines the Insurance Mechanism structure that the Company is continuing to develop with stakeholders and will file for approval subsequent to this case.

Q. How is your direct testimony structured?

A. Section III of my testimony provides an overview of the increased risk of wildfire and the Company's multi-faceted response to those risks, including its efforts to mitigate liability exposure for the Company and its customers. Section IV includes discussion of the steps PacifiCorp has taken to develop the Insurance Mechanism and Catastrophic Fire Fund proposals, description of the stakeholder workshops used to develop the proposals, and identification of procedural paths for adopting them. Section V describes the ICA and how it is necessary to support the Insurance Mechanism in development. Section VI explains the Catastrophic Fire Fund proposal, the origin, and workings of the concept for a wildfire liability liquidity fund, and PacifiCorp's request for authorization to move forward with creating the fund in this proceeding. Section VII addresses PacifiCorp's proposals for multi-state allocation of the costs of the Company's proposals.

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

A. I recommend that the Commission:

(1) Approve the Company's proposal to recover third-party liability insurance costs (both deferred and on-going) through a dedicated surcharge, Schedule 80 - Insurance Cost Adjustment. As detailed in Section V of my testimony, the ICA will be used to support a new Insurance Mechanism that the Company is working with stakeholders to develop.

(2) Approve Oregon's participation in and funding of the Catastrophic Fire Fund, described in Section VI, through a dedicated surcharge, Schedule 193, to be effective January 1, 2025.

(3) Approve the jurisdictional allocations of the costs of the ICA and Catastrophic Fire Fund, which take into consideration the 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol (2020 Protocol) and new risk metrics, as addressed in Section VII of my testimony.

III. PACIFICORP INITIATIVES TO MITIGATE COSTS TO ITS CUSTOMERS ASSOCIATED WITH INCREASING WILDFIRE RISK

Q. What steps is PacifiCorp taking to mitigate the risks associated with wildfire?

A. The increasing incidence and severity of wildfires has had a tremendous impact on PacifiCorp and its customers. Working together with regulators, public safety officials, local communities, other utilities, and our customers, PacifiCorp devotes substantial financial and human capital to addressing the risk of wildfires. As discussed by Company witness Allen Berreth, our approach to wildfire mitigation involves daily operational activities and major investments to minimize the risk of ignition. PacifiCorp is also taking steps to manage the proliferation of wildfire-related liabilities in order to stem the impact of rising Company costs on customer rates.

Q. Please summarize the Company's actions to mitigate the incidence and severity of wildfires.

A. PacifiCorp's Oregon 2024 Wildfire Mitigation Plan (WMP) details the Company's initiatives to date and plans for future mitigation of wildfire risk.[1] The WMP describes investments to construct, maintain and operate electrical lines and equipment in a manner that will minimize the risk of wildfire. In evaluating which engineering, construction, and operational strategies to deploy, the Company's actions are guided by the following core principles:

[1] *See*, Docket No. UM 2207, *PacifiCorp's 2024 Wildfire Mitigation Plan* (Dec. 29, 2023) (*WMP)*. The Commission approved PacifiCorp's 2023 WMP, with recommendations for inclusion in the 2024 WMP, in Docket No. UM 2207, Order 23-220 (June 26, 2023).

- Frequency of ignition events related to electric facilities can be reduced by engineering more resilient systems that experience fewer fault events.

- When a fault event does occur, the impact of the event can be minimized using equipment and personnel to shorten the duration to isolate the fault event.

- Systems that facilitate situational awareness and operational readiness are central to mitigating fire risk and its impacts.

In 2023, guided by these principles, PacifiCorp invested approximately $52.1 million in capital and $26.5 million of expense in Oregon to further many of the Company's wildfire mitigation strategies, including:

- Procurement of new risk modeling tools, datasets, and software.

- Installation of 161 incremental weather stations. The Company now has over 450 stations installed to monitor weather conditions.

- Continued implementation of increased asset inspections, enhanced asset inspections, and accelerated condition correction.

- Continued transition to a three-year vegetation management cycle.

- Scoping and initiation of design for approximately 125 miles of covered conductor.

- Rebuilt approximately 801 miles of overhead lines with covered conductor.

- Replacement of approximately 1,000 expulsion fuses and other expulsion equipment with non-expulsion designs.

- Upgraded 65 relays and reclosers for enhanced functionality.

PacifiCorp's Oregon 2024 WMP incorporates the Company's 2023 experience as well as feedback and recommendations from Staff, stakeholders, and communities. As a result, in 2024 the Company is forecasting an additional investment in Oregon of $975 million through 2028 (across five years), comprised of $780 million capital and $195 million expense.

In addition to the WMP for Oregon, PacifiCorp prepares, and files wildfire mitigation plans in Utah, California, and Washington.[2] The Company is also preparing to file wildfire mitigation plans to document the modeled risks and mitigation efforts for our service areas in Idaho and Wyoming.

Q. Does PacifiCorp expect its mitigation efforts will eliminate wildfire risks in its service territories?

A. No. While utility wildfire mitigation efforts are important and represent good utility practice, they are not sufficient to fully eliminate wildfire risks in a fire-prone regions like that served by the Company. Even if mitigation efforts effectively reduce the risk of ignition, the extreme weather conditions that increasingly accompany fire outbreaks amplify the risk that a wildfire will cause substantial damage once it has started. In addition, responsibility to mitigate wildfires is distributed across numerous agencies and individuals whose action or inaction may result in damages regardless of a utility's performance. Not all wildfire risks can be resolved by PacifiCorp or by any utility or regulator. In fact, additional societal or policy changes beyond the utility industry or the Commission's control are needed to thoughtfully address expected future wildfire impacts. But until those broader societal changes can be accomplished, PacifiCorp needs regulatory solutions now to address this risk to support our ability to obtain reasonable access to financing required to ensure adequate, reliable service.

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[2] *See, In the Matter of Rocky Mountain Power's 2023 Utah Wildland Fire Protection Plan*, Docket No. 23-035-44, Utah Wildfire Mitigation Plan for 2023-2025 (filed Sept. 25, 2023) (available at https://pscdocs.utah.gov/electric/23docs/2303544/329969UTWldfrMtgtnPln202320259-25-2023.pdf) (last visited Feb. 7, 2024); California Office of Energy Infrastructure Safety, Docket No. 2023-2025 WMPs, PacifiCorp California 2023 Wildfire Mitigation Plan, filed May 8, 2023 (available at https://efiling.energysafety.ca.gov/Lists/DocketLog.aspx?docketnumber=2023-2025-WMPs) (last visited Feb. 7, 2024); *In the Matter of Utility Wildfire Preparedness,* Docket No. U-210253, PacifiCorp Washington Wildfire Mitigation Plan, filed April 14, 2022 (available at https://www.utc.wa.gov/casedocket/2021/210254/docsets) (last visited Feb. 7, 2024).

Q. In those occasions where wildfire damages occur, what steps is PacifiCorp taking to manage risk of liabilities and attendant impacts on customer rates?

A. Exposure to various types of liability has always been inherent in a utility's broad obligation to serve and its operation of facilities distributed throughout large geographic service areas. The Company manages the unpredictable financial impacts of such claims in three primary ways: situational awareness and system hardening to prevent occurrence of damages; limits on liability incorporated in its tariffed terms of service; and the use of insurance to cover larger liabilities.

All of these risk mitigation methods protect customers from exposure to rate impacts resulting from a utility's need to incorporate extraordinary damages expense in its revenue requirement. As detailed in the Company's WMP, PacifiCorp continues to expand the situational awareness and system hardening tools available to mitigate wildfire risk. Liability limitations and insurance procurement costs have historically been authorized by the Commission. PacifiCorp incorporates liability limitations in its Oregon tariffs,[3] and the Commission reviews and approves insurance expenses in the Company's rate proceedings.[4] The Company is taking steps to update these mechanisms with the goal of providing financial stability during this time of unprecedented volatility stemming from growing wildfire liability risk.

[3] *See, e.g.,* Pacific Power, Oregon General Rules and Regulations, Rule 14, Continuity of Electric Service and Interruption and Service Restoration, P.U.C. Or. No. 36, Original Sheet No. R14-1 (effective March 22, 2011): "The Company does not guarantee constant or uninterrupted delivery of electric service and shall have no liability to its Consumers or any other persons for any interruption, suspension, curtailment or fluctuation in electric service or for any loss or damage caused thereby if such interruption, suspension, curtailment or fluctuation results from the following:" which is followed by: (a) detailed descriptions of causes "beyond the Company's control"; (b) occasions when the Company repairs, maintains, or replaces facilities; (c) actions necessary to protect the integrity of the electrical system; and (d) conservation actions necessitated by anticipated resource deficiency.

[4] *See, e.g., In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. 374, Order No. 20-473, at 108 (Dec. 18, 2020) (Approving "insurance expenses" for "policies [that] cover claims in any state and are allocated to all states because the policies cover system-allocated assets").

Q. How is the Company seeking to update its tariffed liability limitations?

A. The Company filed requests with its state regulators to align existing tariffs by limiting damages arising out of the Company's provision of electric service to actual economic damages. In Oregon, the Company's application, which initiated docket UE 428, proposes to add language to Rule 4 of the Company's existing tariff.[5]

Q. How is the Company seeking to address the impacts of wildfire issues on its procurement of liability insurance?

A. The Insurance Mechanism and Catastrophic Fire Fund both offer tools for adjusting traditional protections against claims volatility to the new realities of the Company's wildfire risks. The remainder of my testimony will focus on the development and proposed implementation of these tools.

IV. DEVELOPMENT OF THE COMPANY'S INSURANCE MECHANISM AND CATASTROPHIC FIRE FUND PROPOSALS

Q. What prompted the Company to develop the Insurance Mechanism and Catastrophic Fire Fund Proposals?

A. Over the last few years the landscape for obtaining commercial insurance to cover wildfire risk has radically changed and seems likely to continue to become more challenging. Regional claims for third-party liability for past wildfires, combined with increasing uncertainty about the financial impacts expected from future fire events, drove PacifiCorp's commercial insurance costs to unprecedented levels. When it renewed commercial liability insurance policies in August 2023, the Company experienced, as the Commission noted in its Order on PacifiCorp's request for

[5] *In the Matter of PacifiCorp, dba Pacific Power, Advice No. 23-018 (ADV 1545), Modifications to Rule 4, Application for Electrical Service*, Docket No. UE 428.

deferral of insurance costs, an "increase from the $29 million currently in rates to $125 million (a $96 million increase) for the policy period starting August 15, 2023."[6]

Q. How does the Company's 2023 renewal compare to historical experience with commercial liability insurance coverage and costs?

A. Like many utilities, the Company purchases insurance with Associated Electric & Gas Insurance Services Limited (AEGIS) as the primary insurer and builds a follow-form tower above to build up insurance limits. "Follow-form" means the insurers higher in the tower follow AEGIS policy provisions with some minimal modifications at each layer. AEGIS coverage indemnifies insureds for claims arising from sudden and accidental third-party bodily injury and property damage, meaning general liability, inclusive of wildfire liability.[7] The coverage is specifically tailored for all activities in which an electric or gas utility may engage. Prior to 2020, many of the Company's insurers included all wildfire coverage within the utility excess liability tower.

In 2022-23, PacifiCorp's policy year expenditure for excess liability insurance was $34 million. General utility risk limits within the coverage were for claims up to $530 million. The 2022-23 policy had a primary $10 million self-insured retention and various layers of self-insurance including $35 million in California wildfire limits and $55 million in utility risk limits.

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[6] *In the Matter of PacifiCorp dba Pacific Power, Application for Authorization of Deferred Accounting Related to Insurance Costs for Wildfires*, Docket No. UM 2301, Order No. 24-021, Appendix A, at 4-5 (Jan. 24, 2024) (*hereinafter*, *Insurance Deferral Order)* (approving PacifiCorp's request for deferral). PacifiCorp's currently approved rates in Oregon include premiums for commercial insurance covering third-party liability for claims in excess of $10 million (the Company self-insures for small claims under $10 million).

[7] AEGIS coverage is available only to electric, gas and water utilities and adds some areas of coverage that are in addition to general liability. The expanded coverages include auto liability, employer's liability, products liability, completed operations liability, failure to supply, sudden and accidental pollution, medical malpractice, and aircraft liability, amongst others.

The increased costs for commercial excess liability insurance for the 2023-24 policy year were far beyond anything the Company has experienced before. Excess liability insurance costs were up 269 percent in one year, and the 2023-24 policy year represents a 1,888 percent increase over the last five years.[8] At the same time, coverage limits have not kept pace, with similar limits to 2019 now costing the Company an incremental $116 million annually. The changes in costs and coverage since 2018 are detailed in Table 1.

Table 1: Historical PacifiCorp excess liability insurance costs and limits, with breakouts for wildfire coverage (2018-23)

PacifiCorp	2023	2022	2021	2020	2019	2018
Total Costs for Excess Liability	$122,577,486	$33,142,371	$27,511,482	$9,524,782	$6,165,626	$3,456,421
Total Excess Liability Limit	$542,500,000	$530,000,000	$515,000,000	$517,500,000	$517,500,000	$485,000,000
Wildfire Sub limits:						
CA	$344,750,000	$145,000,000	$145,000,000	$95,000,000	$98,000,000	$147,500,000
OR/WA	OR $348,250,000 WA $363,250,000	$188,000,000	$170,500,000	$415,000,000	$415,000,000	
ID/UT/WY	$458,250,000	$232,500,000	$215,000,000	$427,500,000	$427,500,000	
Year over Year Increase in Costs	270%	20%	189%	54%	78%	
Increase in Costs from 2019	1,888%	438%	346%	54%		

Based on the 2023 experience, it was clear to the Company that it must seek workable alternatives before it faces its next insurance renewal in August 2024.

Q. In addition to the increasing insurance costs, were there other developments in 2023 that drove the Company to develop the Insurance Mechanism and Catastrophic Fire Fund?

A. Yes. Recent developments in the utility and insurance industries regarding wildfire events are making it increasingly clear that, barring legal or regulatory interventions: (a) commercial rates for wildfire liability coverage will continue their dramatic rise

[8] PacifiCorp additionally purchased $123.75 million in third-party insurance for property damage-only caused by wildfire. This indemnifies PacifiCorp for claims from homeowners and business insurers who are seeking to recover costs they paid to their insureds and claimants who had property damage that was uninsured or underinsured.

and (b) utilities should expect that wildfire liability coverage will become less available from commercial insurers, if it is offered at all. As reported in the trade publication *Insurance Journal* in July 2023, insurers have taken note of the fact that "[l]liability on the scale imposed by the Oregon jury [in the *James* litigation] presents an existential threat to an industry that faces increasing wildfire risk from more extreme weather fueled by climate change."[9] Company witness Coleman provides support for the expected increase in premiums.

Q. Have the increased wildfire liability risks had additional impacts on PacifiCorp?

A. Yes, credit ratings agencies cited wildfire risk, in particular potential losses associated with the fires in September 2020 and the 2022 McKinney fire, as the direct cause of a ratings downgrade for PacifiCorp in the second half of 2023. In its June 20, 2023, notice that it was downgrading PacificCorp, Standard & Poor's (S&P) stated:[10]

- "…we believe the operating risks for PacifiCorp have significantly increased."
- "To incorporate the increasing event risk that may depress credit metrics over our forecasts associated with the potential litigations, we revised our financial policy modifier to negative from neutral. Overall, we assess PacifiCorp's stand-alone credit profile (SACP) at 'bb+', reflecting our revised view of PacifiCorp's business risk profile and financial policy modifier."

Similarly, a Moody's analysis issued on June 23, 2023, included the following:[11]

- "Wildfires are a significant risk for PacifiCorp's service territory in Oregon, Utah, and California. While such wildfire risk has not been on the scale of

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[9] Joel Rosenblatt, *Utility Investors Wary of Exposures After Buffet's PacifiCorp Held Liable for Wildfires*, INSURANCE JOURNAL (July 19, 2023), available at: https://www.insurancejournal.com/news/national/2023/07/19/731224.htm. *See also,* S&P Global Ratings Direct, *A Storm Is Brewing: Extreme Weather Events Pressure North American Utilities' Credit Quality*, Nov. 19, 2023), available at: https://www.spglobal.com/ratings/en/research/articles/231109-a-storm-is-brewing-extreme-weather-events-pressure-north-american-utilities-credit-quality-12892106(online registration required).

[10] S&P Global Ratings, Research Update: PacifiCorp Downgraded to BBB+, Outlook Revised to Negative: Berkshire Hathaway Energy Co. Outlook Also Negative, June 20, 2023, p. 2.

[11] Moody's Rating Action: Moody's revises PacifiCorp's outlook to negative, affirms ratings, June 23, 2023.

its California investor-owned utility peers, it could still substantially impact its credit profile."

- "Moody's could stabilize PacifiCorp's rating if there is more clarity on the potential claims emanating from the outstanding class action lawsuit regarding the 2020 Labor Day fires, the claims are settled or largely resolved and that any litigation liability is financed in such a way that does not result in significantly higher debt leverage and maintains PacifiCorp's credit metrics at current levels."

In November 2023, Moody's downgraded PacifiCorp's senior unsecured issuer rating to Baa1 from A3.[12] In December 2023, Moody's noted that wildfire risk was a significant risk for the Company and has a substantial impact on its credit profile.[13] Company witness Nikki L. Kobliha discusses the Company's credit metrics further in her testimony.

In January 2024, the Commission adopted a Staff Report recommending approval of PacifiCorp's deferred accounting for 2023-24 insurance expenses. In recommending approval of deferred accounting, the Staff Report stated that "PacifiCorp does face significant financial risks," and determined that "the aggregate effect of the [ratings downgrades] and the insurance cost increase poses a threat to the financial security of the Company."[14]

Q. How will the Insurance Mechanism and the Catastrophic Fire Fund address the challenges facing the Company?

A. The growing risk of wildfire liability is driving negative financial outcomes that have impacted the Company's financial stability and will influence PacifiCorp's future ability to provide service at reasonable rates. PacifiCorp's proposals in this

[12] Moody's Rating Action: Moody's downgrades PacifiCorp to Baa1, outlook stable, at 1.
[13] Moody's Investors Services, Credit Opinion, PacifiCorp, Update following a downgrade to Baa1, December 4, 2023, at 1.
[14] *Insurance Deferral Order*, Appendix A, at 4.

proceeding are focused on an issue that is central to maintaining financial stability: how to supplement, or perhaps replace, the current combination of self-insurance and commercial liability insurance that no longer provides sufficient coverage—at a reasonable cost or at any cost—to address wildfire liability claims. The Insurance Mechanism and Catastrophic Fire Fund seek to alter the existing insurance tower framework, moving PacifiCorp from the "Current" to "Proposed Future" states summarized in Table 2:

Table 2: Current vs. Proposed Regulatory Mechanisms for Liability Coverage

Current State	Proposed Future State
Uncovered Risk Limits on wildfire coverage will leave large potential liabilities uninsured. Carrying such unbounded financial exposure is not sustainable.	Catastrophic Fire Fund A pool of funds drawn on only for extremely large claims that exceed insurance coverage. Creates a multi-state, Company-wide vehicle for managing the largest liabilities without sustaining negative credit impacts that could lead to major rate increases for customers.
Commercial Insurance Used for all excess liability coverage but exorbitant costs and sub-limits for wildfire coverage – or unavailability of wildfire coverage – will force reduced reliance on commercial policies.	Insurance Mechanism Provides more economic sustainable cost for wildfire liability coverage through use of commercial insurance and/or self-insurance, funded by a targeted surcharge.
	Commercial Insurance Commercial insurance will continue to be used for non-wildfire related needs.
Self-Insured Retention A retention for smaller claims continues to make economic sense even as other arrangements change.	Self-Insured Retention The Company expects an insurance retention similar to today's level – covering claims up to $10 million – remains a prudent approach in the future.

The goal of the regulatory tools proposed by PacifiCorp is to create some stability in an increasingly unsustainable legal, regulatory, and financial environment, while maintaining flexibility to adjust liability coverage as circumstances change and policy responses evolve.

Q. What steps has the Company taken to develop its recommendations?

A. PacifiCorp gathered information from its own experience with wildfire mitigation and insurance issues. In addition, the Company examined responses to increasing climate change risks in other states. The Company drew from models such as the California Utility Wildfire Fund and the disaster mitigation framework adopted by Florida regulators, which was established to protect utility credit quality in light of increasingly extreme hurricane events. The Company retained The Brattle Group to evaluate and support the Company's development of regulatory tools. As discussed in more detail later in my testimony, PacifiCorp is also working on additional analysis to assist in informing the liability coverage level that should be supported by the proposed Insurance Mechanism and Catastrophic Fire Fund.

Q. Has PacifiCorp discussed its proposals with stakeholders?

A. Yes. PacifiCorp recognized that the proposed solutions would benefit from input from all of the states in which it operates. To facilitate input, PacifiCorp has convened an ongoing series of meetings and workshops with the participants in the Multi-State Process (MSP). To date, the Company has met with stakeholders in conjunction with MSP meetings in Portland and Salt Lake City and provided remote participation options for all of the workshops. Additional workshops are scheduled through July 2024 to be able to incorporate evolving information into the proposals. The participants include stakeholders who are involved in PacifiCorp's MSP. This group regularly addresses, and has developed substantial expertise in, cost allocation issues in PacifiCorp states. The MSP consideration of traditional cost allocation issues shares similarities with the issues that will arise in allocation of insurance and liability costs under the new proposals. Moreover, the MSP includes a broad representation of regulators, consumer representatives, and other participants in the Company's state regulatory proceedings.[15]

Q. What has been the outcome of the workshops?

A. The workshops have provided an opportunity for the Company and stakeholders to "level set" on the nature of the challenges posed by unbounded wildfire liability and the diminishing options for wildfire insurance. In its presentations, PacifiCorp has discussed options for addressing the challenges, with a focus on reaching consensus on actionable and effective regulatory mechanisms that could be timely implemented. As noted above, the workshop process will continue after this filing. PacifiCorp has committed to provide further information and details associated with the Insurance Mechanism and the Catastrophic Fire Fund proposals in future workshop sessions as more information becomes available.

Q. How does PacifiCorp view the interplay of the ongoing workshops and this Oregon rate proceeding?

A. PacifiCorp has included a forecast of commercial premiums for the test period in this case, along with the proposed amortization (over three years) for the deferred costs approved in docket UM 2301. The Company is seeking to recover the excess liability premium costs through a separate rider, the ICA, to be effective January 1, 2025. Recovery of these costs through a separate adjustment tariff will facilitate the new Insurance Mechanism, discussed in the next section, which the Company intends to

[15] To the extent they are not already attending, PacifiCorp will invite intervenors to this proceeding to participate in future Workshops (subject to agreement to confidentiality protections applicable to settlement discussions).

file for approval separately. Filing for approval of the Insurance Mechanism separately allows for the Company to incorporate additional data and stakeholder feedback into the filed proposed mechanism. Filing separately will also allow for a different procedural schedule for the Insurance Mechanism, as the Company will be seeking approval prior to August 2024 ahead of its insurance renewals.

The Company acknowledges that it is unusual to have solutions that it advocates for in a general rate case being simultaneously further sharpened in a multi-state collaborative process. In substance, however, the setting is not so different from parties' normal process of seeking settlement on issues during the pendency of a contested case. There are two key considerations that make fostering this dual track process advantageous. First, PacifiCorp cannot avoid making its decision on commercial liability insurance renewals by August 15, 2024, because its current insurance contracts expire on that date. Prior to August 1, 2024, the Company hopes to work with the Commission and stakeholders to authorize the Company's proposals. A separate filing for the Insurance Mechanism provides a procedural vehicle that the parties and the Commission can utilize to advance consideration of liability insurance issues in time to reach resolution before PacifiCorp must finalize 2024-25 policy year arrangements while the forecast costs of the policies continue to be part of the GRC for ratemaking.

Second, as noted above, the "Proposed Future State" summarized in Table 2 involves regulatory structures that must necessarily include all PacifiCorp states. For example, current insurance costs are allocated based on the "System Overhead" factor in the 2020 Protocol.[16] If PacifiCorp's proposal for additional insurance options are adopted, those changes will need to flow through the MSP allocation process. It is thus imperative to continue the multi-state collaboration and information-sharing that has characterized the ongoing workshop process.

V. THE INSURANCE MECHANISM OFFERS A NEW LEAST COST INSURANCE COVERAGE OPTION AND PROMOTES FINANCIAL STABILITY

Q. Why is the Company developing a new insurance mechanism to address the wildfire insurance challenges you have identified?

A. Commercial insurance is an excellent option for managing liability risk, but only when it provides sufficient coverage at a reasonable cost. If a business can adequately capitalize it, a self-insurance program can provide several benefits. First, a company can customize its insurance for coverage that may not be readily available in commercial markets. This is the situation PacifiCorp faces with the changes in options available for insuring wildfire liability risk. Second, self-insurance avoids overheads, transaction costs, and risk premiums associated with commercial insurance. If PacifiCorp's proposal is adopted, the Company would have more control over its insurance expenditure, and more flexibility to adapt what it spends on insurance to changing circumstances. Moreover, when claims are low a self-insurance reserve can provide customers a better value because every dollar collected remains

[16] The 2020 Protocol "describes the way all components of PacifiCorp's regulated service, including costs, revenues, and benefits associated with generation, transmission, distribution, and wholesale transactions should be allocated and assigned among the six States during the Interim Period." 2020 Protocol, § 1. The "Interim Period" refers January 1, 2020, to December 31, 2025, the period during which the approved 2020 Protocol remains in effect. *Id*. at 4 (2020 Protocol, § 1). *See* Docket No. UM 1050, Order No. 23-229 (June 30, 2023) (extending the effective date of 2020 Protocol through December 31, 2025).

available for use in the future versus paying annual premiums regardless of claims made.

Q. What are the key design elements of the proposed Insurance Mechanism?

A. There are three fundamental design elements important to any insurance program. To summarize it at a high level, there are three questions the Company must answer to design and implement a successful Insurance Mechanism.

(1) What is the amount of coverage the mechanism will provide?

(2) What is the source and amount of the funds available to pay claims?

(3) How will any self-insurance Insurance program be managed, and the reserve funds invested?

The participants in the workshops have discussed these issues and continue to work with the Company toward optimal answers to each of the key questions. In formulating its proposal PacifiCorp is assuming the Insurance Mechanism would be structured to use a self-insurance reserve to fill any gaps in the insurance tower and replace commercial insurance for wildfire coverage in the event commercial insurers no longer offer sufficient wildfire coverage at a reasonable price. My testimony also provides an illustrative example of the Insurance Mechanism that includes both commercial and self-insurance.

Q. How will the Company determine the amount of coverage the Insurance Mechanism will provide?

A. A critical aspect of developing the new insurance mechanism is to identify what is the appropriate amount of insurance coverage to target obtaining through commercial and/or self-insurance. The first step in determining coverage amounts is to prepare thorough estimates of expected losses. In the case of wildfire liability exposure, loss estimates would be comprised of, at a minimum, estimated third-party property damage, bodily injury, wildfire suppression, and legal costs. However, developing reliable loss estimates is a complex task that will benefit from other analysis inputs which will take additional time.

Q. What is the Company's proposal regarding the source and amount of the funds available to pay claims?

A. The Insurance Mechanism would be comprised of both commercial products and self-insurance, to the extent that the cost and availability of commercial products remains a prudent component for achieving the targeted coverage amount. PacifiCorp proposes using the ICA proposed in this GRC as the funding source. The ICA would be set to collect a reasonable amount to pay for the targeted liability coverage amount. Annually the Company would continue to try to obtain commercial insurance products to meet that coverage level. If commercial products are not available at a reasonable cost to meet the coverage target, the Company would use the ICA collections that are in excess of the annual commercial premiums to fund a self-insurance reserve. As such, all payments into the Insurance Mechanism are the equivalent of insurance premiums for commercial insurance. The self-insurance reserve would build over a number of years up to the coverage target amount and once collections to the self-insurance reserve reach the targeted coverage level, the self-insurance collections would cease until replenishment was needed. The Company will make more specific recommendations on how to establish a level of contribution to the self-insurance reserve when it separately files the Insurance Mechanism for approval. In this case, however, the Company is seeking approval of the ICA with the underlying and minimal expectation that it will be used to fund commercial premiums that will be in effect for the test period. After the test period, the ICA surcharge could support a self-insurance program in lieu of higher cost commercial premium products.

Q. Commercial insurance policies usually include a deductible amount paid by the insured. Would the Insurance Mechanism include a deductible amount paid by the Company?

A. Yes. In typical insurance policies, deductibles provide an incentive to minimize claims and reserve coverage expenditures for more significant events. Low- or no-deductible policies usually come at a much higher cost to insureds. PacifiCorp's existing $10 million self-retention serves this purpose: covering smaller claims without calling on insurance in a way that could lead to higher premiums in the future. PacifiCorp proposes the Insurance Mechanism include an additional deductible, or co-insurance, component. PacifiCorp proposes a deductible arrangement where the Company would pay 2.5 percent of claims over $350 million (total Company), with an annual cap of $10 million (total Company). The inclusion of this co-insurance component is in direct response to feedback from stakeholders in the workshop process to incorporate an incentive for the Company to prudently manage decisions to pay claims to third parties.

Q. How will the self-insurance program be managed and invested?

A. In any insurance program, payment of claims relies on the insurer prudently investing premium payments. Interest and other earnings from investing premiums is essential to building an insurance reserve capable of paying claims up to coverage limits. The Company proposes to invest the surcharge amounts paid into the self-insurance reserve in an interest-bearing account to make sure the collected funds receive a time value of money.

Q. How does PacifiCorp propose the self-insurance program handle investment decisions, claims review, and other functions typically handled by an insurer?

A. PacifiCorp is evaluating creation of a captive insurance company to administer the self-insurance component of the Insurance Mechanism. Captive insurers are companies typically owned and controlled by their insureds. A captive's purpose is limited to insuring the risks of its owners. The Company would retain an experienced insurance administrator to manage the captive company. Captive insurance companies are subject to regulatory requirements, with particular focus on protection of funds devoted to payment of claims.[17] A regulated captive insurer arrangement may be ideal to ensure transparency and confidence that the Company's surcharge-funded Insurance Mechanism is managed prudently. PacifiCorp is continuing discussion in the Workshops regarding arrangements for administering the Insurance Mechanism and is prepared to work with stakeholders and regulators to devise the corporate framework supporting the Insurance Mechanism.

Q. Assuming the design elements proposed by PacifiCorp, please provide an illustrative example of how the Insurance Mechanism would work.

A. Table 3 below provides an illustrative example of the workings of the Insurance Mechanism on a total-Company level, from its inception through a 10-year period. The example assumes: (1) an annual total-Company coverage limit of $750 million;

[17] *See*, National Association of Insurance Commissioners Center for Insurance Policy and Research, *Captive Insurance Companies* (April 3, 2023), available at: https://content.naic.org/cipr-topics/captive-insurance-companies.

(2) a surcharge-funded total-Company premium of $183.9 million per year ($150 million of which is used for commercial premiums); (3) a 2.5 percent deductible for claims over $350 million, capped at $10 million per year; (4) interest earnings of 5 percent per year on balances in the self-insurance reserve; and (5) the Company utilizes a combination of commercial insurance and self-insurance to pay claims. The example also includes varying amounts of claims assumed to be paid each year.

Table 3: Insurance Mechanism – Year 1-10 Illustrative Example (Commercial excess liability insurance and self-insurance reserve funded by ICA)

$millions	Total Collections-Comm Insurance	Total Claims Paid	Self-Retention	Claims Paid - Comm Insurance	Self-Insurance Deductible - Pd by Co	Self-Insurance Beginning Balance	Total Collections-Self Insurance	Claims Paid - Self Insurance	Interest	Ending Self-Ins Reserve
Year 1	150.0	-	-	-	-	-	33.9	-	0.8	34.7
Year 2	150.0	15.0	10.0	5.0	-	34.7	33.9	-	2.6	71.2
Year 3	150.0	10.0	10.0	-	-	71.2	33.9	-	4.4	109.5
Year 4	150.0	-	-	-	-	109.5	33.9	-	6.3	149.8
Year 5	150.0	100.0	10.0	90.0	-	149.8	33.9	-	8.3	192.0
Year 6	150.0	15.0	10.0	5.0	-	192.0	33.9	-	10.4	236.3
Year 7	150.0	50.0	10.0	40.0	-	236.3	33.9	-	12.7	282.9
Year 8	150.0	2,000.0	10.0	490.0	6.3	282.9	33.9	243.8	8.9	82.0
Year 9	150.0	5.0	5.0	-	-	82.0	33.9	-	4.9	120.8
Year 10	150.0	8.0	8.0	-	-	120.8	33.9	-	6.9	161.6

The illustration in Table 3 assumes commercial premiums remain stagnant, which past experience shows is not likely to happen. However, this illustration demonstrates how the Insurance Mechanism is proposed to operate.

VI. THE PROPOSED CATASTROPHIC FIRE FUND OFFERS A SOURCE OF LIQUIDITY WHERE WILDFIRE LIABILITY EXCEEDS COMMERCIAL INSURANCE COVERAGE

Q. How will a Catastrophic Fire Fund address the wildfire liability challenges the Company has identified?

A. The Insurance Mechanism creates a cost-efficient alternative to the increasing insurance expenses associated with wildfire liability. The extraordinary liability risk posed by more and increasingly severe wildfires may nevertheless exceed amounts recoverable from insurance. Regardless of a utility's prudent actions, utilities could face claims in the billions of dollars and may have to reach beyond insurance proceeds to meet those liabilities. Such massive claims on utility assets could compromise the financial stability that utilities require to maintain and expand infrastructure to meet both customer needs and state policies. The Catastrophic Fire Fund proposed by the Company would provide a backstop fund available to facilitate managing what could be an existential financial risk. The Company would use the Catastrophic Fire Fund in the event there are claims in excess of the annual insurance coverage limit.

Q. Is there a model for the Company's proposed Catastrophic Fire Fund?

A. Yes. The most prominent example is the California Wildfire Fund, created in 2019 by the California Legislature (AB 1054). The California Wildfire Fund was created to support the solvency of California investor-owned utilities that were facing massive wildfire liability claims. Notably, AB 1054 was only a part of California's response to growing wildfire risk. Like Oregon, California enacted laws that created new legal requirements for wildfire mitigation plans and authorized securitization for cost recovery under certain circumstances. The California Assembly and courts have also provided additional limits on utility liability and opportunity for cost recovery for wildfire-related claims.[18]

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[18] *See, e.g., See*, *Gantner v. Pacific Gas & Electric Co.*(Nov. 20, 2023, S273340), __ Cal. 4th __ [p. 24] (Cal. Supreme Court 2023) (Ruling that the California Public Utility Commission, rather than the courts, has exclusive jurisdiction over the "supervision and regulation of [Public Safety Power Shutoff] PSPS implementation and review."); Cal. Pub. Util. Code, § 451.1; § 1701.8 (Requires that the CPUC allow cost recovery of just and reasonable costs and expenses arising from a wildfire caused by an electric utility. Costs are "just and reasonable" if "the conduct of the electrical corporation related to the ignition was consistent with actions that a reasonable utility would have undertaken in good faith under similar circumstances.")

Q. Did the creation of the California Wildfire Fund improve financial stability for California utilities?

A. Yes. The California Wildfire Fund currently is available to the three large investor-owned utilities (IOUs) in the state.[19] Credit rating agencies view the creation of the Fund as a positive step for IOU creditworthiness. In a 2021 report, S&P stated:

> We [S&P] view AB 1054 as generally supportive of the IOUs' credit quality. AB1054 created a vehicle for tempering California IOUs' financial exposure to wildfire liability …. California utility wildfire experience could serve as a template for utilities in other fire-prone states to follow.[20]

As noted by S&P, creation of a similarly purposed backstop fund in other states could help utilities like the Company, who have experienced ratings downgrades due to wildfire liability risk.

Q. Would PacifiCorp's Catastrophic Fire Fund be designed like the California fund?

A. There are similarities in the purpose behind PacifiCorp's proposal, but significant differences in how PacifiCorp proposes to design a catastrophic event fund. Like the California Wildfire Fund, PacifiCorp's proposal would establish a risk pool for potential catastrophic wildfire events where the Company's liabilities exceed available insurance. The availability of the risk pool provides liquidity and supports credit quality, similar both to the California Wildfire Fund and the storm reserves used by utilities in high-risk areas states like Florida. Because PacifiCorp operates as a multi-state utility with costs and benefits of the PacifiCorp system shared across all

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[19] Those utilities are Pacific Gas & Electric; Southern California Edison; and San Diego Gas & Electric.
[20] S&P Global, "Credit FAQ: How Are California's Wildfire Risks Affecting Utility Credit Quality," June 3, 2021. *See also,* Moody's Investor Service, "California utility wildfire mitigation efforts have reduced liability exposure," November 10, 2022.

six states, the Company is proposing a multi-state fund that cost-effectively diversifies risks across the shared system and provides customer benefits through the financial stability of the utility. Other key differences in the design of the PacifiCorp Catastrophic Fire Fund proposal involve (1) the size of the fund, (2) how it is funded, and (3) the governance of the fund.

Q. What is the target size of the PacifiCorp Catastrophic Fire Fund?

A. PacifiCorp proposes a target level of $3 billion, total Company, for the Catastrophic Fire Fund. This is much smaller than the California fund, and PacifiCorp believes it is more in line with the level of potential uninsured wildfire risk in PacifiCorp's states. As with the Insurance Mechanism, PacifiCorp will complete additional analysis to inform the appropriate size of the Catastrophic Fire Fund.

Q. What is PacifiCorp's proposed funding mechanism?

A. The Company seeks a balance between fully funding the Catastrophic Fire Fund and moderating the impact of the surcharge needed to fund it. PacifiCorp proposes that the target reserve level be collected over 10 years, at $300 million per year, total Company. The Company proposes to contribute 20 percent of the target fund amount, along with a per event deductible, described below. Customer collections would be funded through a new surcharge, Schedule 193 - Catastrophic Fire Fund Surcharge. The Company proposes implementation of funding as part of the rates that go into effect in in this proceeding on January 1, 2025. For Oregon, the Company is proposing annual contribution of $77.7 million. The proposed jurisdictional cost allocation for customer contributions to the fund is addressed in Section VII. For rate stability, the Company proposes to fix allocations for five years with an update to the allocation inputs for year 6 of the collection period.

Because collections to the fund would occur over a number of years, the fund would act as a balancing account and would only begin to provide meaningful liquidity once a material balance is available in the reserve. A near-term event where uninsured liabilities exceed the reserve balance could require cash funding by PacifiCorp and could result in a liquidity event for the Company. In this scenario, the Catastrophic Fire Fund would be recorded as a regulatory asset on the PacifiCorp financial books and amortized using existing Catastrophic Fire Fund collections until the reserve was fully funded.

As with the Insurance Mechanism, funds would be held in interest-bearing accounts or other appropriate investments to grow the fund balance over time. As the fund nears its target level, a regulatory review would examine the funding level necessary, the level of the supporting surcharge, and the continued need for the fund based on future developments regarding wildfire liability. If at some point in the future it is determined that the fund is no longer needed, any remaining funds after pending claims have been accounted for, including the Company's contributions, would be returned to customers.

Q. Would the Catastrophic Fire Fund include a deductible amount like the Insurance Mechanism?

A. Yes, PacifiCorp proposes a per-event deductible, applicable to each event in which the Catastrophic Fire Fund would be drawn upon to fund claims in excess of the insurance coverage limit. The Company proposes a 5 percent co-insurance per event, capped at $50 million for the life of the fund. The inclusion of a Company funded deductible in addition to its 20 percent contribution to the fund ensures that the Company will prudently manage the claims process.

Q. Assuming the design elements proposed by PacifiCorp, please provide an illustrative example of how the Catastrophic Fire Fund would work from a financial perspective.

A. Table 4 provides an illustrative example of how funds would flow in Year 1-10 of the Catastrophic Fire Fund. As with the example in Table 3, the illustration here includes hypothetical claims paid during the 10-year period to demonstrate the impact of the outflow of claims payments on the accumulation of the target fund balance. The Catastrophic Fire Fund would work in conjunction with the Insurance Mechanism, with all components of the Insurance Mechanism being exhausted before utilizing the Catastrophic Fire Fund. As shown in Table 4, both customer and Company contributions begin to accumulate in the fund balance in an interest-bearing account. In the instance of a catastrophic event, the accumulated balance is then debited, less the proposed co-insurance, for that event. If no event occurs, the fund will continue to grow.

Table 4: Catastrophic Fire Fund – Year 1-10 Illustrative Example

$ - Millions		Fixed Contribution		**Claim Paid**						
	Beginning Balance	Total Customer Contribution	Company Contribution	Claims Paid[1]	Co-Insurance	Recoverable Claim Amount	Interest[2]	Ending Balance	Total Company Contribution	% of Co Contribution
Year 1	-	240	60	-	-	-	8	308	60	20%
Year 2	308	240	60	-	-	-	15	623	60	20%
Year 3	623	240	60	-	-	-	23	946	60	20%
Year 4	946	240	60	-	-	-	31	1,277	60	20%
Year 5	1,277	240	60	-	-	-	39	1,616	60	20%
Year 6	1,616	240	60	-	-	-	48	1,964	60	20%
Year 7	1,964	240	60	-	-	-	57	2,321	60	20%
Year 8	2,321	240	60	1,250	50	1,200	36	1,456	110	31%
Year 9	1,456	240	60	-	-	-	44	1,800	60	20%
Year 10	1,800	240	60	-	-	-	53	2,153	60	20%
Total		2,400	600						650	21%
Target Fund	3,000									
Interest Rate[3]	5%									

Notes:
1) Claims paid are assumed to be made in December 31 of each year.
2) Interest is not paid on regulatory liability balance. Company would fund regulatory liability and need to be reimbursed for cash outflow.
3) Interest rate is used for illustration purposes only. Funds would be held in interest bearing account and earn actual interest.

Q. What governance issues does the Company believe should be addressed as part of Catastrophic Fire Fund formation?

A. As previously noted, as a multi-state risk pool the PacifiCorp Catastrophic Fire Fund needs to consider regulatory review and surcharge funding from all states in which PacifiCorp operates. The Company proposes to address this through creation and approval of an Advisory Board appointed to oversee the Catastrophic Fire Fund.

Q. What would be the role of the Advisory Board?

A. PacifiCorp proposes the Advisory Board would review wildfire events where PacifiCorp seeks to draw on the Catastrophic Fire Fund and issue reports and recommendations to state regulatory commissions. At a minimum, the Board would review: (1) whether the Company's actions were in accordance with documented operational policies and approved WMPs in the state(s) where the event occurred; and (2) whether the claims paid were reasonable. The Board would also be empowered to make recommendations regarding:

- Whether the fund should be replenished back to its target level after claims are paid from the fund;
- Changes in operational policies or mitigation efforts for future wildfire events;
- When to conduct new studies or reports on the size and operations of the fund. New studies may be triggered when legislative or regulatory changes materially alter liability risk in particular states. (Studies would be funded from the reserve balance in the fund).

The Board's recommendations would be advisory and not legally bind either state commissions or the Company. Additionally, the Company would have the option to seek Advisory Board input prior to paying wildfire liability claims from the fund.

Q. How does PacifiCorp propose the Advisory Board be composed?

A. The Company suggests that the Advisory Board be composed of up to nine members: one member would be appointed by state commissions in each PacifiCorp state (six members) and three non-Company employees appointed by PacifiCorp. The Company recommends the Advisory Board meet at least once yearly, and perhaps more often as the Catastrophic Fire Fund is being organized and established.

Q. How does PacifiCorp propose to structure the Catastrophic Fire Fund claims process?

A. The Company proposes that it would notify participating states and the Advisory Board when a potential triggering wildfire event occurs. No more than 90 days after the conclusion of the triggering event (or sooner if feasible), PacifiCorp would file a report detailing the event and PacifiCorp's action during the event. The report would include an estimate of damages and the status and expected timing of known or anticipated event investigations. The Company would provide updated event reports every six months until final resolution, subject to direction from state commissions.

All of the event reports, to the extent necessary, would be subject to confidentiality protections.

Q. How would the Company provide notice of its intent to draw from the reserve fund?

A. PacifiCorp would provide notice to state commissions and the Advisory Board at least 30 days prior to drawing from the fund. The Company's notice would provide documentation that: (1) the funds will be used to pay for wildfire liability damages; (2) the claims from the wildfire event exceed insurance coverage (whether self-insurance or commercial policies); and (3) PacifiCorp acted in accordance with documented operational policies and approved WMPs.

VII. STATE ALLOCATION OF COSTS AND RATE IMPACTS OF INSURANCE MECHANISM AND CATASTROPHIC FIRE FUND

Q. How are liability insurance costs currently allocated in the 2020 Protocol?

A. As a general expense in the administrative and general category, the 2020 Protocol allocates excess liability insurance costs among the PacifiCorp states using the System Overhead (SO) factor.

Q. Has PacifiCorp evaluated other options for allocating the costs of the Company's proposals?

A. Yes. The Company has explored nine potential options for allocating costs among the PacifiCorp states. The cost allocation categories and respective state-specific percentages are provided in Table 5:

Table 5: Cost Allocation Proposals[21]

Option #	Description	CA	OR	WA	UT	ID	WY
1	System Overhead	2.62%	27.43%	7.32%	44.46%	5.45%	12.72%
2	Distribution Line Miles	4.58%	30.02%	6.07%	37.17%	8.70%	13.46%
3	OH Distribution Line Miles	5.62%	33.67%	7.46%	27.08%	9.53%	16.64%
4	T&D Line Miles in State	4.51%	27.54%	5.63%	38.16%	9.93%	14.24%
5	SG Alloc T Line Miles, State D Miles	3.93%	29.38%	6.36%	38.75%	8.06%	13.52%
6	SG Alloc T Miles, State O/H D Miles	4.41%	31.73%	7.47%	32.17%	8.40%	15.82%
7	50% each SO and Dist OH Line Miles	4.12%	30.55%	7.39%	35.77%	7.49%	14.68%
8	1/3 each - SO, OH Dist Lines, EFR Reclosers	14.07%	33.04%	5.57%	32.54%	4.99%	9.79%
9	1/3 each - SO, SG T/OH D, EFR Reclosers	13.67%	32.40%	5.57%	34.24%	4.62%	9.51%

Q. Did the Company consider additional allocation options beyond those listed in Table 5?

A. Yes. While numerous allocation options were theorized, it is important the Company prioritizes options that are readily available and quantifiable. For example, while population density or property values may be factors in wildfire liability risk, the source of the data would be externally provided and subjective. These options were eliminated due to these factors.

Q. What is PacifiCorp's recommendation for allocating the costs in the ICA?

A. Historically, the Company's insurance costs are considered corporate overhead expenses and are allocated using the SO factor (Option1). Since the Insurance Mechanism is proposed to provide a cost-effective option for liability insurance coverage, PacifiCorp recommends continued use of the SO allocation factor for allocating costs of the ICA.[22] The state-by-state percentage allocation of costs using the SO factor is shown for Option 1 in Table 5.

[21] Allocation proposals calculated using year-end 2023 data and SO and System Generation (SG) allocation factors from this general rate case filing.
[22] The proposed ICA currently includes the costs for all excess liability premiums because wildfire coverage is not a readily distinguishable cost in all of the policies.

Q. What is PacifiCorp's recommendation for allocating the costs of the Catastrophic Fire Fund?

A. The Catastrophic Fire Fund is a new regulatory tool and provides a level of liquidity support in excess of what the Company would otherwise seek through insurance. In the workshop discussions, PacifiCorp and stakeholders have discussed an allocation framework that acknowledges the fund is in part a form of insurance but will also have the most utility in the states where the largest and most destructive wildfires are most likely to occur. In examining the Company's service territory, a larger allocation appears appropriate based on two factors. First, the SG allocation of overhead transmission lines plus overhead distribution line mileage in the state since utility wildfire risk is correlated with the presence of overhead line infrastructure. Second, the total Elevated Fire Risk Reclosers (EFR) in a state is a quantifiable representative of higher fire risk areas, therefore the investment in EFRs is appropriately considered in assessing each state's share of wildfire liability risk. To recognize a balance between these factors, the Company proposes to allocate Catastrophic Fire Fund Costs:

- 1/3 System Overhead: SO factor calculation used to allocate system overhead cost including insurance premiums;
- 1/3 SG Transmission/Overhead Distribution – System Generation allocation of total transmission line miles + total distribution overhead line miles for each state; and
- 1/3 Elevated Fire Risk Reclosers – Total installed reclosers by state

Applying this proposed allocation to Catastrophic Fire Fund Costs results in the state-by-state allocations depicted in Table 6:

Table 6: State allocation percentages for proposed Catastrophic Fire Fund costs.

Description	CA	OR	WA	UT	ID	WY
1/3 each - SO, SG T/OH D, EFR Reclosers	13.67%	32.40%	5.57%	34.24%	4.62%	9.51%

Q. If the Commission approves the Insurance Mechanism and Catastrophic Fire Fund using the design criteria recommended by the Company, what would be the overall estimated impact on Oregon customer rates?

A. The estimated impact to Oregon customers is shown in Table 7. It includes the assumptions and cost allocations discussed in my testimony.

Table 7: Oregon Rate Impact of Insurance Mechanism and Catastrophic Fire Fund

($millions)	Oregon Allocated	Estimated Rate Impact
Estimated 2025 Insurance Premiums	$ 50.4	2.8%
Amortization of insurance deferral	$ 15.6	0.9%
Total Insurance Cost Adjustment	$ 66.0	3.7%
Catastrophic Fire Fund	$ 77.7	4.3%

Additionally, removing liability premiums set in the 2023 general rate case, UE 399, decreases base rates by $8.0 million, or (0.4) percent. If the ICA is not approved, then the full costs of the 2025 insurance premiums and amortization of the deferral should be included in base rates.

Q. Does the Company make a recommendation on the class allocation and rate design for the ICA and Catastrophic Fire Fund surcharges?

A. Yes. Class allocations and rate design for the new surcharges are addressed in the direct testimony of Company witness Robert M. Meredith.

VIII. CONCLUSION

Q. Please summarize your recommendations.

A. I recommend that the Commission:

(1) Approve the Company's proposal to recover third-party liability insurance costs (both deferred and on-going) through a dedicated surcharge, Schedule 80 - Insurance Cost Adjustment. As detailed in Section V of my testimony, the ICA will be used to support a new Insurance Mechanism that the Company is working with stakeholders to develop.

(2) Approve Oregon's participation in and funding of the Catastrophic Fire Fund, described in Section VI, through a dedicated surcharge, Schedule 193, to be effective January 1, 2025.

(3) Approve the jurisdictional allocations of the costs of the ICA and Catastrophic Fire Fund, which take into consideration the 2020 Protocol and new risk metrics, as addressed in Section VII of my testimony.

Q. Does this conclude your direct testimony?

A. Yes.

REDACTED
Docket No. UE 433
Exhibit PAC/700
Witness: Mariya V. Coleman

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Direct Testimony of Mariya V. Coleman

February 2024

TABLE OF CONTENTS

I. INTRODUCTION AND WITNESS 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 Mariya V. Coleman. My business address is 2755 E Cottonwood Parkway, Salt Lake City, Utah 84121. I am currently the Vice President of Corporate Insurance and Claims for Berkshire Hathaway Energy Company (BHE), PacifiCorp's parent company.

Q. Please describe your education and professional experience.

A. I joined NV Energy as a Risk Analyst in 2010 and worked in roles of increasing responsibility in corporate insurance through 2017. Since 2015, I have managed PacifiCorp's insurance costs and insurance personnel. In 2017, I was named the Director of Corporate Insurance for BHE and its subsidiaries including PacifiCorp. I assumed my current role as Vice President of Corporate Insurance and Claims in May 2023. I have a Bachelor of Science in Finance from University of Nevada, Las Vegas and a Master of Business Administration from the University of Nevada, Las Vegas.

Q. What are your primary responsibilities as Vice President of Corporate Insurance and Claims for the Company?

A. As Vice President of Corporate Insurance and Claims, I am responsible for the corporate insurance function for BHE and the Company, including the acquisition and management of all corporate insurance programs covering $132 billion in assets.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have testified in regulatory proceedings in Nevada, Utah and Wyoming.

II. PURPOSE AND SUMMARY OF TESTIMONY

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

A. The purpose of my direct testimony is to provide support for the Company's estimated insurance premiums to be collected through the proposed surcharge as detailed in the testimony of Company witness Joelle R. Steward, with the Company seeking an effective date of January 1, 2025, for the proposed rate adjustment.[1] My testimony further supports the recovery of the total deferred liability insurance premiums recorded under docket UM 2301, as detailed in the testimony of Company witness Sherona L. Cheung.[2]

Q. Please summarize your testimony.

A. My testimony provides an overview of excess liability insurance and how wildfire liability risk has impacted the commercial insurance markets causing a recent increase in the premiums for available excess liability insurance coverage. My testimony further addresses the critical need for obtaining excess liability insurance to cover third-party claims and the factors contributing to the recent surge in commercial premiums for such insurance within the commercial markets.

III. OVERVIEW OF INSURANCE PROGRAMS

Q. What types of commercial insurance does PacifiCorp maintain?

A. PacifiCorp maintains a number of types of insurances, including, but not limited to the following categories:

<u>Excess Liability</u>
A claims-made policy form that provides coverage for legal liability to third parties arising out of bodily injury and property damage losses suffered by those third parties.

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[1] Exhibit PAC/600, Steward/4; *see also* Exhibit PAC/1700, Cheung/42-43.
[2] Exhibit PAC/1700, Cheung/42-43.

Punitive Damages
Provides indemnity-only excess liability coverage for punitive damages imposed or awarded against the insured under certain circumstances specified in the policy.

Onshore Property
Covers all risks of physical loss or damage to operating locations (i.e., fire, earthquake, flood, theft, boiler and machinery breakdown, turbine generator breakdown). This coverage includes peripheral coverages such as business interruption at select BHE Renewables sites, increased cost of construction, incidental transit, service interruption, debris removal, accounts receivable, and firefighting equipment.

Terrorism
Provides sabotage and terrorism coverage with respect to property insured under BHE's onshore property program. Terrorism coverage applies to certified and non-certified acts.

Inland Transit and Storage
Coverage is included for BHE transits of turbine rotors, generators, combustion components, exciters, and similar machinery and equipment. Allocation is based on the values of the property shipped.

Wind and Solar Equipment Storage
Provides property coverage for wind and solar equipment in storage for MidAmerican Energy, BHE Renewables, and PacifiCorp projects. Allocation is based on the values of the property in storage.

Large-Deductible Worker's Compensation
Provides statutory coverage once the deductible is met for employees injured directly as a result of their employment with the company.

Excess Workers Compensation
Provides statutory coverage in excess of self-insured retention for employees injured directly as a result of their employment with the company.

Automobile Liability
Coverage for third-party bodily injury and property damage liability arising out of automobile accidents that are BHE's fault. This covers liability arising out of the use of owned, non-owned, and hired automobiles. Coverage does not include physical damage.

Aviation and Unmanned Aircraft Systems
Provides liability for bodily injury and property damage to third parties arising out of the use of owned and non-owned aircraft. The policy also includes physical damage loss to aircraft as well as war and terrorism and sabotage buyback.

purchases for both liability and physical damage. Each aircraft is individually rated, and charges are sent to the business which owns the aircraft.

<u>Occurrence Liability Fronting Policy</u>
Allows BHE to have insurance certificates issued for contracts that require an occurrence-based commercial general liability policy form.

<u>Surety Bonds</u>
Used for contractual obligations of BHE businesses where that business is required to have a surety company financially guarantee to an obligee that the BHE business will act in accordance with the terms established in the bond. All businesses pay their own individual bond premium.

Q. Please explain how PacifiCorp's liability insurance is structured in current rates.

A. The Company has included insurance premium cost in prior Oregon general rate cases. In particular, PacifiCorp's current approved rates incorporate premiums for commercial insurance that provide third-party liability coverage for claims exceeding $10 million, while the Company self-insures for lesser claims up to $10 million.

Q. Please describe how PacifiCorp procures commercial excess liability insurance.

A. PacifiCorp's excess liability insurance is purchased as part of BHE's aggregated insurance purchase, which allows PacifiCorp to leverage BHE's size and expertise. Excess liability insurance includes the following major areas of coverage: general liability, wildfire liability, auto liability and employer's liability. Claims for damages to third-parties are included within excess liability coverage.

Q. How are the excess liability premiums allocated to PacifiCorp?

A. PacifiCorp's excess liability premiums are allocated through BHE's corporate allocation. BHE's corporate allocation calculates an average percentage of property, plant and equipment; employee count; loss history; overhead electric transmission and distribution lines; and transmission and distribution pipeline miles.

Q. What are the cost associated with excess liability insurance included in this case?

A. As explained in the testimony of Company witness Cheung, the Company proposes an excess liability insurance premium amount of $50.4 million (Oregon-allocated) to be recovered through a separate surcharge effective January 1, 2025.[3] This amount reflects the Company's estimate of excess liability premiums for the test period.

Q. Is the estimate of excess liability insurance premium costs based on the most recent premiums issued to the Company?

A. Yes. The premiums for excess liability presented in this proceeding are derived from the most recent renewal of its commercial insurance policies in August 2023, with a projected 50 percent increase applied for the 2025 test period. My testimony will provide a rationale why the Company's estimate of excess liability premiums for the test period is appropriate.

IV. EXCESS LIABILITY INSURANCE PREMIUMS

Q. Why is it necessary for PacifiCorp to have sufficient excess liability coverage to continue providing low-cost electric service in Oregon?

A. Maintaining insurance is a necessary part of operating a utility and managing the risks associated with that business. Excess liability insurance protects the Company and customers against financial losses from third-party claims in Oregon and other states in which the Company provides utility service. However, wildfire risk for utilities in the western United States (U.S.) has radically changed in the past few years, and the premiums for available commercial excess liability insurance have significantly increased.

[3] Exhibit PAC/1700, Cheung/42-43.

Q. What has caused the excess liability premium increase?

A. Wildfires across the western U.S. have resulted in significantly increasing wildfire costs and an inability to acquire insurance at rates and coverage levels that have been consistent with past premiums. Insurers have increased the price at which they will consider selling insurance covering claims from wildfire liability. Additionally, insurers who historically would consider selling wildfire liability will no longer do so. Excess liability insurance premium costs in 2023 are 3.7 times the Company's 2022 insurance premiums. 2023 premiums are 18 times higher than 2019 premiums for comparable insurance coverage. Excess liability insurance, including wildfire liability insurance, is a prudent business expense that protects the Company and customers against financial losses from third-party claims.

Q. What are the impacts to the excess liability premiums?

A. As just previously explained, because the wildfire risk for utilities in the Western U.S. has radically changed in the past few years, the premiums for available commercial liability insurance have significantly increased.

Q. Do you believe that commercial premiums for excess liability will continue to increase?

A. Yes. The Company views the premium increases encountered since 2019 as a sign of the continued elevated expenses it anticipates for future excess liability coverage. This expectation is due to the ongoing challenges related to wildfire insurance.

Q. Can you further explain the timing for the increase in premiums?

A. Typically, the Company executes renewals of insurance policies in August of each year. All costs are related to excess liability insurance premiums related to coverage for third-party claims brought against PacifiCorp resulting from providing service to its customers.

Q. What is the Company's estimate of excess liability premiums for the test period?

A. Based on recent trends, a compounded annual program-wide increase of at least 25 percent in 2024 and 2025, informs a 50 percent increase over current costs. Accordingly, the excess liability premiums are estimated to be approximately $183.9 million, which on an Oregon-allocated basis, translates to $50.4 million.[4]

[redacted] However, excess liability premiums for the test period are currently the Company's best estimates based on currently available information. As better information becomes available throughout the proceeding, the Company will provide further updates to the estimates amounts as necessary.[5]

Q. How are liabilities associated with wildfires covered under the prior and current commercial insurance policies?

A. The total amount of insurance per occurrence is $458.25 million with varying sub-limits for occurrences between states. Claims in any state use up the total amount of the limit available for all states. This means that if there is a claim in one state, then

[4] Exhibit PAC/1700, Cheung/42-43.
[5] Exhibit PAC/1700, Cheung/43.

there is less insurance available for the next claim in any other state. Liabilities prior to this renewal were covered similarly to how they are after the August 15, 2023, renewal with an increase in the amount of cumulative, shared insurance limit as reflected below:

August 15, 2022 – August 14, 2023		August 15, 2023 – August 14, 2024	
State	**Shared Total Limit**	**State**	**Shared Total Limit**
CA	$110m	CA	$344.75m
ID, UT, WY	$232.5m	ID, UT, WY	$458.25m
OR, WA	$188m	WA	$363.25m
		OR	$348.25m

Most policies are issued with a single cost for all states, with just a few outliers insuring just California or Oregon, separately. Without purchasing additional insurance products for each individual state, at an incremental cost, insurers will not differentiate how much risk is allocated by state any further than reflected in the statement above.

Q. How do insurers handle coverage for PacifiCorp's multiple states?

A. Insurers impose sub-limits within a policy to differentiate risks between various states. These sub-limits allow PacifiCorp to insure the entire system at lower cost for our customers.

Q. How did the Company determine the level of reasonable liability insurance coverage?

A. The Company evaluated wildfire claims results from the Western U.S. and purchased available insurance limits that were offered by the market. Liabilities can exceed the current insurance coverage limits that were purchased in the event of a catastrophic wildfire.

Q. Why is it reasonable and prudent for these insurance premium costs to be included in Oregon rates?

A. Maintaining insurance is a necessary part of operating a utility and the risks associated with that business. Utilities maintain insurance at different levels when compared to other industries in order to avoid the volatility of claims on customer rates, especially in an environment when the utility does not directly control the pricing of the service it provides.

Oregon customers have benefitted materially from excess liability insurance coverage including recovery of over $450 million system-wide since 2010, which offsets claims paid by PacifiCorp. These insurance recoveries directly reduce the cost of claims paid, providing financial stability for both the Company and its customers.

V. RECOVERY OF INSURANCE DEFERRAL

Q. Is the Company requesting the recovery of total deferred liability insurance premium?

A. Yes. As explained in the testimony of Company witness Cheung:

> [T]he Company anticipates that the total deferred liability insurance premiums to be recorded under docket UM 2301 will be approximately $41.3 million, before accrual of interest, on an Oregon-allocated basis. The Company is proposing to amortize the total Oregon-allocated deferred amounts, plus interest accrual, over a three-year amortization period. Accordingly, annual amortization amount is estimated to be approximately $15.6 million.[6]

[6] Exhibit PAC/1700, Cheung/42.

Q. Were these deferred amounts prudently incurred and should they be recovered in rates?

A. Yes. Excess liability insurance constitutes a prudent business expenditure that safeguards both the Company and its customers from financial setbacks arising from third-party claims. In fact, PacifiCorp's currently approved rates include expenses related to excess liability insurance premiums. Although the premiums for commercial insurance have escalated for electric utilities since the Company's previous general rate case, these costs remain a prudent expense and ought to be included in rates.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 433
Exhibit PAC/800
Witness: Rick T. Link

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Rick T. Link

February 2024

TABLE OF CONTENTS

ATTACHED EXHIBITS

Exhibit PAC/801—Transmission Projects Analysis

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 Rick T. Link. My business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My position is Senior Vice President, Resource Planning, Procurement and Optimization.

Q. Please describe the responsibilities of your current position.

A. I am responsible for PacifiCorp's energy supply management and resource planning and procurement functions, which includes the integrated resource plan (IRP), structured commercial business and valuation activities, and long-term load forecasts. Most relevant to this docket, I am responsible for the economic analysis used to screen system resource investments and conducting competitive request for proposal (RFP) processes, consistent with applicable state procurement rules and guidelines.

Q. Briefly describe your education and professional experience.

A. I joined PacifiCorp in December 2003 and assumed the responsibilities of my current position in September 2021. I have held several analytical and leadership positions responsible for developing long-term commodity price forecasts, pricing structured commercial contract opportunities and developing financial models to evaluate resource investment opportunities, negotiating commercial contract terms, and overseeing development of PacifiCorp's resource plans. I have been heavily involved in developing PacifiCorp's IRPs since 2013; have been directly involved in several resource RFP processes; and performed economic analysis supporting a range of resource and transmission investment opportunities. Before joining PacifiCorp, I was an energy and environmental economics consultant with ICF Consulting (now ICF International) from 1999 to 2003, where I performed electric-sector financial modeling of environmental policies and resource investment opportunities for utility clients. I received a Bachelor of Science degree in Environmental Science from the Ohio State University in 1996 and a Master of Environmental Management from Duke University in 1999.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have testified in proceedings before the Public Utility Commission of Oregon (Commission), the California Public Utilities Commission, the Idaho Public Utilities Commission, the Utah Public Service Commission (Utah Commission), the Washington Utilities and Transportation Commission , and the Wyoming Public Service Commission.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your direct testimony?

A. I provide economic analysis that supports PacifiCorp's decision to build two transmission projects, including: (1) Gateway South, a 414-mile, 500-kilovolt (kV) overhead transmission line between the Aeolus Substation, near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah; and (2) Gateway West Segment D.1, a 59-mile, 230-kV transmission line from the Shirley Basin substation in southeastern Wyoming to the Windstar substation near Glenrock, Wyoming and the accompanying ancillary facilities (collectively, the Transmission Projects).

I also summarize PacifiCorp's assessment of the projects from the 2021 IRP and 2021 IRP update, provide background on PacifiCorp's 2020 All-Source Request for Proposal (2020AS RFP) to solicit new resources, including those enabled by the Transmission Projects, and discuss customer benefits that result from the projects.

For details regarding Gateway South and Gateway West, please refer to the direct testimony of Company witness Richard A. Vail.

Q. Please summarize your testimony for the Transmission Projects.

A. The 2021 IRP confirmed that the Transmission Projects remain a key transmission investment that will enable the procurement of low-cost wind facilities to reliably meet the Company's need for additional resources. These resources are expected to produce significant customer benefits. This includes ensuring that all new wind resources from the 2020AS RFP that depend on the Transmission Projects: (1) qualify for 110 percent of available federal production tax credits (PTC), further reducing the cost of these resources (that already have no fuel costs or emissions) relative to other resource options; and (2) generate renewable-energy certificates (RECs) that can be used to offset revenue requirements where appropriate.

As discussed by Company witness Vail, the Transmission Projects will also provide critical voltage support to the Wyoming transmission network, improve overall reliability of the transmission system, and enhance PacifiCorp's ability to comply with mandated reliability and performance standards. Most importantly, the Transmission Projects ensure the Company will meet its obligations to reliably accommodate nearly 2,500 megawatts (MW) of interconnection and transmission service requests, including 13 executed interconnection service and transmission service agreements for over 1,600 MW of new wind resources. This includes 500 MW of firm point-to-point (PTP) transmission service to a third-party transmission customer under the Federal Energy Regulatory Commission's (FERC) jurisdiction. Moreover, the Transmission Projects create additional opportunity to increase transfer capability with the construction of additional segments of the Energy Gateway project.

Q. Please summarize your economic analysis of the Transmission Projects.

A. My economic analysis demonstrates that the Transmission Projects are necessary and in the public interest. In my analyses, I reviewed the change in revenue requirement due to the Transmission Projects, and associated resources that are dependent upon the Transmission Projects, using the Company's IRP modeling tool across five different scenarios that pair varying natural gas price assumptions with varying carbon dioxide (CO_2) policy assumptions (price-policy scenarios). For each price-policy scenario, I calculated the change in system revenue requirement between cases with and without the Transmission Projects through 2040, where capital revenue requirement is levelized. The price-policy scenarios include:

- Medium natural gas prices paired with medium CO_2 prices (MM);
- Medium natural gas prices without a CO_2 price (MN);
- High natural gas prices paired with high CO_2 prices (HH);
- Low natural gas prices without a CO_2 price (LN); and
- The Social Cost of Greenhouse Gas (SCGHG).

These analyses confirm that the Transmission Projects are expected to generate customer benefits. Under the MM price-policy scenario, the present-value revenue requirement differential (PVRR(d)) customer benefit when using the most conservative assumptions for unavoidable transmission is $128 million and the risk-adjusted PVRR(d) benefits are $260 million. When assuming the cost of the Transmission Projects are unavoidable, the PVRR(d) under the MM price-policy scenario yields a $610 million customer benefit and a risk-adjusted benefit of $742 million. Conservatively, these benefits do not assign any value to the RECs that will be generated by new resources made available due to the Transmission Projects. The risk-adjusted results indicate that the Transmission Projects add significant risk mitigation benefits associated with volatility in market prices, loads, hydroelectric generation, and unplanned outages.

Q. Did you develop an additional calculation to measure how changes in cost might influence customer benefits?

A. Yes. I produced a calculation to determine how changes in resource and transmission cost assumptions would impact customer benefits. My review of resource costs show that assumed initial capital costs would need to increase by 32 percent to erode the customer benefits from the MM price-policy scenario. Similarly, the cost of the Transmission Projects would need to increase by 50 percent to erode the benefits from the MM price-policy scenario. These results show that the projected customer benefits are robust, and that they persist even if the resource costs and transmission costs far exceed the estimates that were available when we committed to move forward with the Transmission Projects.

Q. Did you continue to review the economic analysis after the Company began construction of the Transmission Projects?

A. Yes. I revisited the economic analysis as we were finalizing contracts for the wind resources dependent upon the Transmission Projects. This update accounted for, among other things, higher costs, higher PTC values associated with the passage of the Inflation Reduction Act (IRA), and the potential impacts of the Ozone Transport Rule (OTR). This review showed risk-adjusted customer benefits totaling $247 million in the MM price-policy scenario.

Q. Do you believe your testimony supports the prudency of the Company's investments for both Transmission Projects?

A. Yes.

III. GATEWAY SOUTH AND GATEWAY WEST SEGMENT D.1

A. Need

Q. Did the 2021 IRP identify the need for additional resources to serve PacifiCorp's customers?

A. Yes. The primary focus of the 2021 IRP is to forecast the need for resources and then evaluate different ways to meet that need over time. In the 2021 IRP, the assessment of resource need is presented in Volume I, Chapter 6. The load-and-resource balance shows that PacifiCorp has a capacity deficit in all years of the planning horizon—starting at 1,071 MW in 2021, and increasing to over 6,600 MW by 2040.[1] In 2025, the first full year that the Transmission Projects will be online, the resource need is 1,627 MW. Consistent with prior IRPs, all resource portfolios produced in the 2021 IRP that were considered as candidates for the preferred portfolio contain new supply-side, demand-side, and market resources to fill this need.

This need has continued to increase due to increases in forecasted load. The 2021 IRP Update shows a resource need in all years of the planning horizon—starting

[1] *See* PacifiCorp 2021 Integrated Resource Plan, Vol. I, Table 6.12.

at 1,584 MW in 2022 and increasing to 6,755 MW in 2040.[2] In 2025, the first full year that the Transmission Projects will be online, the resource need is 1,867 MW, an increase of 240 MW or approximately 15 percent from the 2021 IRP. The higher load reflected in the 2021 IRP Update approaches the level analyzed in the high-load sensitivity conducted in the 2021 IRP.[3]

Since the Company initiated construction of the Transmission Projects, national tariff policies, global supply-chain issues, and inflationary pressures eliminated some bids on the 2020AS RFP final shortlist. Consequently, PacifiCorp's procurement was reduced by 902 MW of solar resources and 497 MW of battery storage resources. Additional resources are needed to reduce PacifiCorp's reliance on the market.

Q. Why is it important to reduce PacifiCorp's reliance on market purchases?

A. There is a strong consensus that the western United States will face an increasing capacity deficit in the near future.[4] For example, in December 2020, the Western Electricity Coordinating Council (WECC) issued its Western Assessment of Resource Adequacy Report (WARA).[5] The WARA was developed based on data collected from balancing authorities describing their own demand and supply projections over the next 10 years. The WARA evaluated resource adequacy among six subregions under two scenarios—one with and without imports to the subregion. PacifiCorp serves load in three of these subregions—Northwest Power Pool Northwest (NWPP-

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[2] *Id.* at Table 4.2.
[3] *Id.* at 2.
[4] *Id.* at Vol. I, Ch. 5.
[5] *The Western Assessment of Resource Adequacy Report,* Western Electricity Coordinating Council (Dec. 18, 2020) (https://www.wecc.org/Administrative/Western%20Assessment%20of%20Resource%20Adequacy%20Report%2020201218.pdf).

NW), Northwest Power Pool Northeast (NWPP-NE), and Northwest Power Pool Central (NWPP-C). For each of these scenarios, the WARA considered variations of supply. The most conservative assumes availability of only existing resources, and the most liberal includes availability of new resources under construction, those expected to come online, and those under development. The study found that for each of the three subregions in which PacifiCorp serves load, imports are needed to meet a one-day in 10-year planning threshold. The WARA shows that the NWPP-NW subregion would fall short of the planning threshold in 194 hours (under the most liberal supply case) to 208 hours (assuming availability of only existing resources) without imports. In the NWPP-NE and NWPP-C subregions, the study found that planning threshold is not met in 4,200 hours without imports.

These findings highlight that there are real reliability risks associated with relying on supply being available in the market to meet projected load obligations. In addition, WECC's 2021 WARA issued December 2021 further concludes that not only are resource adequacy risks to reliability likely to increase over the next 10 years, it recommends entities take immediate action to mitigate near-term risks and prevent long-term risks. The 2021 WARA projects that "by 2025, each subregion, and the interconnection, will be unable to meet the 99.98%-one-day-in-ten-year-reliability threshold."[6]

[6] *2021 Western Assessment of Resource Adequacy Report*, Western Electricity Coordinating Council (Dec. 17, 2021) (https://www.wecc.org/Administrative/WARA%202021.pdf).

Q. Are there any other third-party studies confirming the resource adequacy concerns in the west?

A. Yes. In December 2020, the North American Electric Reliability Corporation (NERC) issued its Long-Term Resource Adequacy (LTRA) study that included its 10-year WECC region reliability assessment.[7] The NERC LTRA calculates an anticipated resource-based reserve margin to a reference reserve margin to establish one of three risk determinations—adequate (anticipated margin exceeds the reference margin), marginal (anticipated margin is below the reference margin, but new resources under development could cover the shortfall), and inadequate (anticipated reserve margin is below the reference margin and load interruption is likely).

The NERC LTRA shows that the Northwest Power Pool region and Rocky Mountain Reserve Group regions are projected to be inadequate beginning in 2028 even if resources under development come online. Again, these findings highlight the risk of relying on other entities in the region to have excess supply available for the market when PacifiCorp may be required to buy power to serve its customers.

Q. How did the 2021 IRP preferred portfolio address the need for new resources?

A. The 2021 IRP preferred portfolio represented PacifiCorp's least-cost, least-risk plan to reliably meet customer demand over a 20-year planning period, based on the information available at the time the plan was developed. Using a range of cost and risk metrics to evaluate numerous resource portfolios, PacifiCorp selected a preferred portfolio that reflected a cost-conscious plan with near-term investments in renewable resources that capture tax credits before they expire or decrease, and new

[7] *2020 Long-Term Reliability Assessment*, North American Electric Reliability Corporation (Dec. 2020) (https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2020.pdf).

transmission infrastructure to facilitate the interconnection and delivery of these resources. These new resources and transmission investments are lower cost than other resource and transmission alternatives and are necessary to reliably serve our customers.

Q. Were the Transmission Projects part of the 2021 IRP preferred portfolio?

A. Yes. As described in Volume I, Chapter 4 of the 2021 IRP, the preferred portfolio includes both Gateway South and Gateway West Segment D.1. In the 2021 IRP, the Transmission Projects are assumed to be placed in service by the end of 2024, consistent with current construction timelines discussed by Company witness Vail. The Transmission Projects will enable the addition of new wind facilities that contribute to meeting 1,627 MW of projected resource need beginning 2025.

Q. Did the Commission acknowledge the Transmission Projects in the 2021 IRP?

A. Yes, and the Commission noted that it expected PacifiCorp to provide adequate analyses of the costs and benefits of transmission projects in future proceedings.[8] I believe my testimony provides the appropriate economic analyses to inform the Commission's request on this issue.

Q. Were the Transmission Projects part of the 2021 IRP Update?

A. Yes.[9]

Q. What new transfer capabilities and interconnection capacity do the Transmission Projects add to PacifiCorp's system?

A. The Transmission Projects will increase the transfer capability between the Aeolus

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[8] Order No. 22-178 (May 23, 2022).

[9] PacifiCorp's 2021 Integrated Resource Plan Update, Ch. 7, Action Plan Item 3a–3b, at 103–104 (Mar. 31, 2022) (https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2021_IRP_Update.pdf).

substation in eastern Wyoming and the Clover substation located near Mona, Utah by 1,700 MW, and enable the interconnection of 2,030 MW of new resources in eastern Wyoming.

Q. Please describe key factors supporting the inclusion of the Transmission Projects as prudent investments in this case.

A. The Transmission Projects allow PacifiCorp to implement system improvements, support the full capacity rating of Gateway South and West, and enable the addition of incremental Wyoming renewable resources to support customer needs and deliver value for customers in the most cost-effective way. As discussed by Company witness Vail, the Transmission Projects will also improve overall reliability of the transmission system, and enhance PacifiCorp's ability to comply with mandated reliability and performance standards. Importantly, at the time PacifiCorp committed to move forward with building these new transmission assets, the Transmission Projects would ensure the Company could meet its obligations to reliably accommodate nearly 2,500 MW of interconnection and transmission service requests, including 13 executed interconnection service and transmission service agreements for over 1,600 MW of new wind resources. This included 500 MW of firm PTP transmission service to a third-party transmission customer under the FERC's jurisdiction.

Q. Please describe the reliability benefits of the Transmission Projects.

A The Transmission Projects directly connect eastern Wyoming to central Utah while enhancing reliability throughout PacifiCorp-served regions. Connecting to the Mona/Clover market hub provides additional flexibility in the use of least-cost resources from eastern Wyoming or southern Utah.

Moreover, allowing additional generation resources to interconnect and serve load will lessen PacifiCorp's reliance on volatile and potentially diminishing market transactions to serve load. Given concerns over regional resource adequacy, reducing reliance on the market ensures a stable and reliable supply of capacity and energy going forward.

In addition, Gateway South improves reliability by relieving the stress on the transmission system in eastern Wyoming and central Utah. Gateway South relieves stress on the underlying 230-kV transmission system in Wyoming, and it unloads the underlying 345-kV transmission system in central Utah, improving reliability in both regions. Essentially, the 500-kV line brings two distant areas closer to each other in a way that improves regional reliability.

Gateway West Segment D.1 creates a new transmission path that allows for additional resource development in the area. The addition of this line improves the reliability of the transmission system during certain identified outage conditions (Dave Johnston to Amasa 230-kV outage or Amasa – Shirley Basin 230-kV outage). Gateway West Segment D.1 is also a prerequisite for interconnecting new resources, including those selected in the 2020AS RFP. Company witness Vail's testimony addresses transmission system reliability and interconnection issues in greater detail.

B. <u>The 2020AS RFP</u>

Q. Please provide an overview of the 2020AS RFP.

A. The 2020AS RFP was issued to identify resources that could meet the Company's projected resource need identified in the 2019 IRP. Based on the cost-and-performance assumptions for proxy resources in the 2019 IRP, the Company expected that new wind, solar and battery energy storage systems (BESS) were likely to be the most cost-competitive types of resources offered into the 2020AS RFP. However, bidders could offer proposals for other types of resources (*i.e.*, natural gas, pumped storage, *etc.*).

Q. When was the 2020AS RFP issued?

A. After receiving approval from the Utah Commission (docket 20-035-05) and Oregon Commission (docket UM 2059), PacifiCorp issued the 2020AS RFP on July 7, 2020.[10]

Q. What was the market response to the 2020AS RFP?

A. There was a robust market response that resulted in over 28,000 MW of conforming bids, with an additional 12,500 MW of non-confirming bids. Bids for 24 projects totaling over 9,000 MW of resource capacity located in eastern Wyoming were submitted.

Q. How did the Company evaluate submitted bids?

A. The Company created an initial shortlist that was made public on October 29, 2020. This shortlist included 5,453 MW of renewable resource capacity: 2,974 MW of solar or solar with storage (1,130 MW of battery storage), 2,479 MW of wind, and 200 MW of standalone BESS. PacifiCorp then initiated a capacity factor evaluation

[10] In Oregon Administrative Rules 860-89-0010, et seq., the Oregon Commission has established competitive bidding requirements for certain resource acquisitions by Oregon's investor-owned utilities. *In the Matter of the Rulemaking Regarding Allowances for Diverse Ownership of Renewable Energy Resources*, Docket No. AR 600, Order No. 18-324, Appendix A (Aug. 30, 2018) (https://apps.puc.state.or.us/orders/2018ords/18-324.pdf). In addition, Utah's Energy Resource Procurement Act requires a competitive solicitation process before the acquisition of renewable resources greater than 300 MW *See* Utah Code Ann. § 54-17-201 *et. seq.*

process (performed by third-party expert WSP Global). The initial shortlist contained a mix of various ownership structures, including proposals for power-purchase agreements (PPAs), build-transfer agreements (BTAs), and battery storage agreements (BSAs).

Q. What resources were selected to the final shortlist?

A. After evaluating a range of potential bid portfolios, and accounting for bid updates from interconnection study results, the final shortlist included: 1,792 MW of new wind capacity (590 MW as BTAs and 1,202 as PPAs); 1,302 MW of solar capacity as PPAs; 697 MW of BESS (497 MW of BESS capacity paired with solar bids, and 200 MW as standalone BESS capacity as a BSA).[11]

Q. Which final shortlist resources depend on the Transmission Projects for interconnection?

A. Six final shortlist resources, representing over 1,600 MW of wind generation, require the Transmission Projects to interconnect to PacifiCorp's transmission system. Table 1 summarizes the wind resources that require the Transmission Projects to achieve interconnection.

[11] The final shortlist originally included an additional solar bid collocated with BESS. Shortly after the bidder was notified its project was on the final shortlist, it withdrew the bid from the 2020AS RFP. This bid is not included in the total capacity.

Table 1. 2020AS RFP Wind Bids Dependent on the Transmission Projects for Interconnection

Project	Bidder	Structure	Capacity (MW)
Cedar Springs IV	NextEra	PPA	350
Boswell Springs	Innergex	PPA	320
Two Rivers	BlueEarth Renewables LLC and Clearway Renew LLC	PPA	280
Anticline	NextEra	PPA	101
Rock Creek I	Invenergy	BTA	190
Rock Creek II	Invenergy	BTA	400

Q. Was the 2020AS RFP overseen by independent evaluators?

A. Yes. Consistent with Utah and Oregon Commissions' requirements, the solicitation process was overseen by two independent evaluators—one retained by PacifiCorp and appointed by the Oregon Commission (PA Consulting Group, Inc.), and one retained by the Utah Commission (Merrimack Energy Group).

Q. What were the independent evaluators' conclusions regarding the 2020AS RFP?

A. Both independent evaluators concluded that the process was fair and transparent, and that the bids selected for the final shortlist were reasonable.

Q. Please describe the Utah independent evaluator's conclusions regarding the 2020AS RFP.

A. In its Shortlist Report, the Utah independent evaluator concluded that the RFP was fair, reasonable, and in the public interest.[12] In particular, the Utah independent evaluator concluded:

- The market response to the RFP was robust and, "Based on the unbelievable response from the market it is safe to say that the solicitation process resulted in a very competitive process with many more proposals generally submitted than the expected requirements by bubble identified by PacifiCorp."[13]

[12] *In re Rocky Mountain Power 2020AS RFP Application,* Docket No. 20-035-05 (Utah Public Service Commission; Sept. 2, 2021) (https://psc.utah.gov/2020/01/24/docket-no-20-035-05/).
[13] Utah Independent Evaluator Shortlist Report at 74.

- PacifiCorp engaged the bidders throughout the process in a timely manner to ensure that all bidders were treated fairly.
- All bidders were treated the same, had access to the same information at the same time, and had an equal opportunity to compete.
- PacifiCorp implemented its evaluation and selection process consistent with its proposed evaluation and selection process as outlined in the RFP in a structured and consistent manner designed to result in the selection of a portfolio of projects that would result in a least cost solution.
- PacifiCorp subjected all bidders to the same information requirements and conducted a consistent evaluation process with all proposals treated equally in terms of the evaluation methodology and information required of each bidder.
- The selection process was unbiased with respect to ownership structures, i.e., the process did not unreasonably favor bids that resulted in a utility-owned resource.
- The selected bids resulted in lower system cost than a case where no bids were selected and maximized customer benefits while managing risk.

Q. Please describe the Oregon independent evaluator's conclusions regarding the 2020AS RFP.

A. In its Closing Report, the Oregon independent evaluator concluded that the final shortlist reflected a diverse portfolio of competitive resources that achieves the resource adequacy and least cost goals set forth in PacifiCorp's IRP.[14] This was based on the following conclusions:

- PacifiCorp's procurement process, scoring methodology and results were fair and free of bias across all bids and bidders.
- PacifiCorp applied the rules of the 2020AS RFP in an unbiased manner, communicated transparently with the independent evaluators regarding their modelling processes and with stakeholders regarding their decisions.
- PacifiCorp's bid price scores were on average consistent with the independent evaluator's independent scoring methodology.

[14] *In re PacifiCorp's 2020AS RFP Application,* Docket No. UM 2059 (Oregon Commission; Jun. 15, 2021) (https://apps.puc.state.or.us/edockets/DocketNoLayout.asp?DocketID=22320).

- PacifiCorp's utilization of an outside consultant, WSP Global, to evaluate wind, solar, and battery storage benefitted stakeholders.

- The final shortlist was reasonably aligned with the 2019 IRP preferred portfolio.

Q. Did the Oregon Commission acknowledge the shortlist?

A. Yes.[15] Acknowledgement means that the Oregon Commission found that the "final shortlist appears reasonable at the time of acknowledgment and was determined in a manner consistent with [Oregon's] competitive bidding rules."[16] The Oregon Commission noted that the final shortlist "is a reasonable capacity and energy blend, with diversity in contract structures (and therefore rate impact profiles), technology types, and geography."[17]

C. Price-Policy Assumptions

Q. Please summarize the natural gas and CO_2 price assumptions used in the economic analysis.

A. The economic analysis of the Transmission Projects includes five price-policy scenarios—MM, MN, HH, LN, and SCGHG. These assumptions can influence the value of system energy, the dispatch of system resources, and PacifiCorp's resource mix. Consequently, wholesale-power prices and CO_2 policy assumptions affect net-power cost (NPC) benefits, non-NPC variable-cost benefits, and system fixed-cost benefits associated with the Transmission Projects. Because wholesale power prices and CO_2 policy outcomes are both uncertain and important drivers to the economic analysis, it is important to evaluate a range of assumptions for these variables. Table 2

[15] Docket No. UM 2059, Order No. 21-437 (Nov. 24, 2021) (https://apps.puc.state.or.us/orders/2021ords/21-437.pdf).
[16] *Id.* at 12.
[17] *Id.* at 13.

summarizes the price-policy scenarios used to analyze the Transmission Projects.

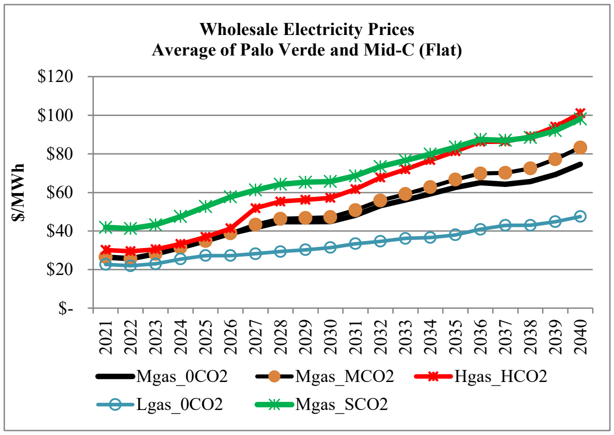
Table 2. Price-Policy Scenario Assumption Overview

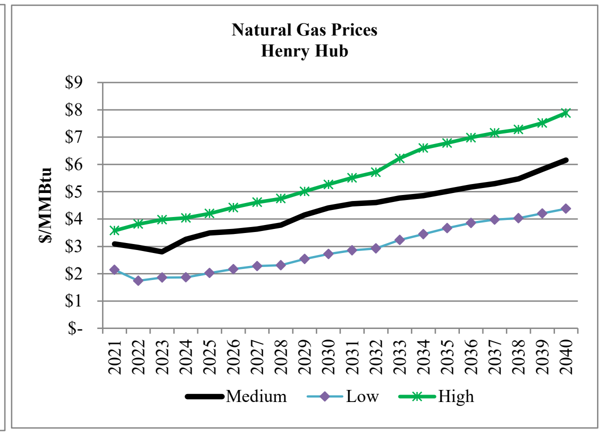
Price-Policy Scenario	Henry Hub Natural Gas Price (Levelized \$/MMBtu)	CO_2 Price Description
MM	\$4.44	\$9.93/ton starting 2025 rising to \$57.94/ton in 2040
MN	\$4.44	None
HH	\$5.64	\$22.57/ton starting 2025 rising to \$102.48/ton in 2040
LN	\$2.94	None
SCGHG	\$4.44	\$74.10/ton starting 2021 rising to \$150.38/ton in 2040
*Nominal levelized Henry Hub natural gas price from 2025 through 2040.		

Q. Please describe the natural-gas price assumptions used in the price-policy scenarios.

A. The medium natural gas price assumptions are from PacifiCorp's official forward price curve (OFPC) dated March 31, 2021, which was the most current OFPC available when PacifiCorp prepared its modeling inputs for the 2021 IRP. The first 36 months of the OFPC reflect market forwards at the close of a given trading day (March 31, 2021, in this case). As such, these 36 months are market forwards as of March 2021. The blending period (months 37 through 48) is calculated by averaging the month-on-month market forwards from the prior year with the month-on-month fundamentals-based price from the subsequent year. The fundamentals portion of the natural gas OFPC reflects an expert third-party, multi-client "off-the-shelf" price forecast. The fundamentals portion of the electricity OFPC reflects prices as forecast by AURORAXMP4 (Aurora), a WECC-wide market model. Aurora uses the expert third-party natural gas price forecast to produce a consistent electricity price forecast for market hubs in which PacifiCorp participates. Figure 1 shows Henry Hub natural-gas price assumptions for the medium, high, and low natural gas price scenarios.

Figure 1. Natural Gas Price Assumptions

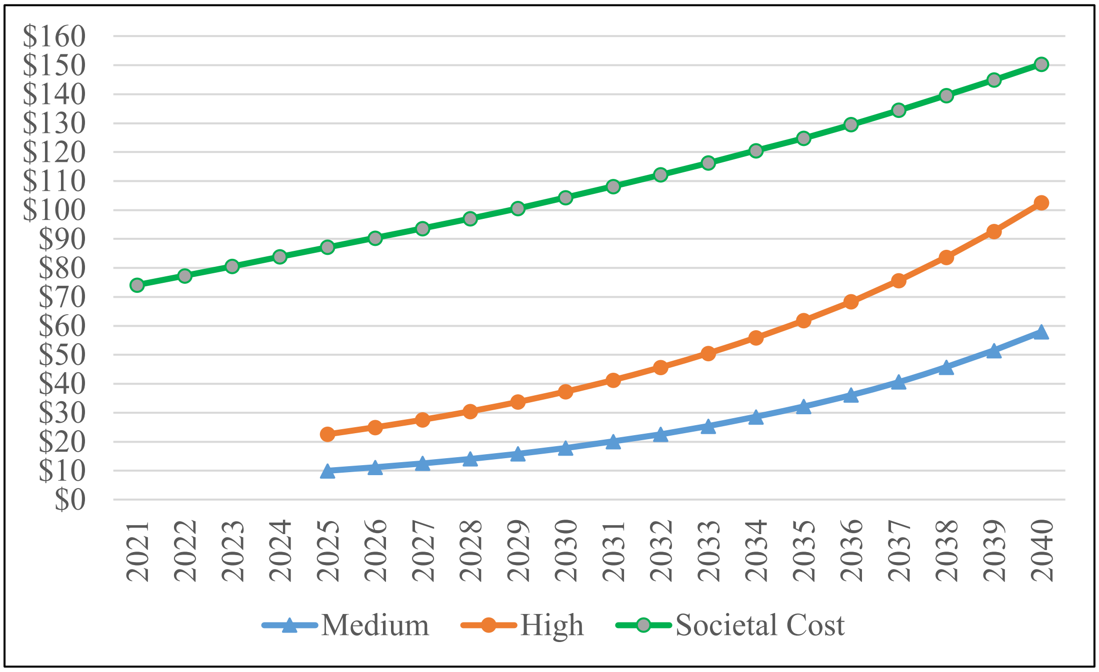




Q. Please describe the CO_2 price assumptions used in the price-policy scenarios.

A. PacifiCorp used four different CO_2 price scenarios in the 2021 IRP—zero, medium, high, and a price forecast that aligns with the social cost of greenhouse gases. The medium and high scenario are derived from expert third-party, multi-client "off-the-shelf" subscription services. Both scenarios apply a CO_2 price beginning 2025. PacifiCorp also incorporated the social cost of greenhouse gas, which is assumed to start in 2021. The social cost of greenhouse gases is applied such that the price for the social cost of greenhouse gas is reflected in market prices and dispatch costs for the purposes of developing each portfolio (*i.e.,* incorporated into capacity expansion optimization modeling). Figure 2 shows the three non-zero CO_2 price assumptions used to analyze the Transmission Projects.

Figure 2. CO_2 Price Assumptions



Q. How did PacifiCorp pair the natural gas and CO_2 price assumptions for purposes of its analysis of the Transmission Projects?

A. Scenarios pairing medium gas prices with alternative CO_2 price assumptions reflect OFPC forwards through April 2024 before transitioning to a fundamentals forecast. Scenarios using high or low gas prices, regardless of CO_2 price assumptions, do not incorporate any market forwards because these scenarios are designed to reflect an alternative view to that of the market. As such, the low and high natural gas price scenarios are purely fundamental forecasts. Low and high natural gas price scenarios are also derived from expert third-party, multi-client "off-the-shelf" subscription services.

Q. Does including potential future CO_2 costs reflect prudent utility planning?

A. Yes. The Company's price-policy scenarios include varying levels of assumed CO_2 costs to reflect the fact it is more likely than not that some policy will exist that will drive reduced emissions over the life of the Transmission Projects. When determining CO_2 costs used for planning purposes, the Company strives to ensure that it is not an outlier as discussed above, and the medium price is within a reasonable range used by the industry to assess risk and conduct prudent resource planning.

Q. Are the modeled CO_2 costs intended to represent a literal carbon tax?

A. No. The modeled CO_2 costs are not intended to explicitly account for a future tax on CO_2 emissions. Rather, these costs capture the effect of policies incentivizing reduced emissions through benefits or imposing costs through penalties or other costs resulting from market dynamics driving the need for zero-emission resources or customer preferences.

D. Modeling Methodology

Q. Please describe the modeling methodology PacifiCorp used in its analysis of the Transmission Projects.

A. PacifiCorp calculated a system present-value revenue requirement (PVRR) by identifying least-cost resource portfolios and dispatching system resources through 2040, which aligns with the 20-year forecast period used in the 2021 IRP. Net customer benefits are calculated as the PVRR(d) between two simulations of PacifiCorp's system. One simulation includes the Transmission Projects, and the other simulation excludes them. In addition, because wind bids selected from the 2020AS RFP located in eastern Wyoming cannot interconnect without the Transmission Projects, these wind resources are also eliminated from the simulation without the Transmission Projects. When the two simulations are compared, changes to system costs are attributable to the Transmission Projects and associated wind resources from the 2020AS RFP final shortlist.

Customers are expected to realize benefits when the system PVRR from the simulation with the Transmission Projects is lower than the system PVRR without the Transmission Projects. Conversely, customers would experience increased costs if the system PVRR with the Transmission Projects were higher than the system PVRR without the Transmission Projects.

Q. Are there any other costs that differ between the simulations with and without the Transmission Projects?

A. Yes. The simulation that excludes the Transmission Projects includes the cost of transmission upgrades necessary to accommodate PacifiCorp’s obligation to provide 500 MW of firm PTP transmission service to a third-party customer. As explained in more detail by Company witness Vail, these transmission upgrade costs were included because, even conservatively ignoring all the executed interconnection service and transmission service contracts listing the Transmission Projects as prerequisites and focusing solely on the upgrades required to provide service under one transmission service contract, PacifiCorp assumed it would need to construct a 230-kV line by the end of 2024 at an estimated cost of approximately $1.4 billion.

Further, this $1.4 billion cost is the minimum cost for the alternative considering that it includes only the upgrades required to provide service under a single transmission service contract. Additional costs would be incurred to provide service under all interconnection service contracts listing the Transmission Projects as prerequisites. To provide service under all these contracts, it is likely the alternative would be to construct the Transmission Projects, which means that construction of these transmission investments are unavoidable given PacifiCorp's federal open access transmission tariff obligations to grant interconnection and transmission service requests.

Q. Please describe the modeling tool used to create the economic analysis of the Transmission Projects.

A. PacifiCorp uses the PLEXOS modeling system. The PLEXOS modeling system provides three platforms of the PLEXOS tool (referred to as Long-term (LT), Medium-term (MT) and Short-term (ST)), which work on an integrated basis to inform the optimal combination of resources by type, timing, size, and location over PacifiCorp's 20-year planning horizon. The PLEXOS tool also allows for improved endogenous modeling of resource options simultaneously, greatly reducing the volume of individual portfolios needed to evaluate impacts of varying resource decisions.

Q. Please describe how PacifiCorp used the LT model.

A. PacifiCorp used the LT model to produce unique resource portfolios across a range of different planning cases. Informed by the public-input process, PacifiCorp identified case assumptions that were used to produce optimized resource portfolios, each one unique regarding the type, timing, location, and amount of new resources that could be pursued to serve customers over the next 20 years. Portfolios from the LT model are informed by an hourly review of reliability based on ST model simulations (described below). This ensures that each portfolio meets minimum reliability criteria in all hours.

Q. Please describe how PacifiCorp used the MT model.

A. PacifiCorp used the MT model to perform stochastic risk analysis of the portfolios. Each portfolio was evaluated for cost and risk among five price-policy scenarios (MM, MN, HH, LN, and SCGHG). A primary function of the MT model is to calculate an optimized risk-adjustment, representing the relative risk of a portfolio under unfavorable stochastic conditions for that portfolio.

Q. Please describe how PacifiCorp used the ST model.

A. PacifiCorp used to ST model to evaluate each portfolio to establish system costs over the entire 20-year planning period. The ST model accounts for resource availability and system requirements at an hourly level, producing reliability and resource value outcomes as well as a PVRR, which serves as the basis for selecting least-cost, least-risk portfolios. As noted above, ST model simulations were also used to identify the potential need for resources in the portfolio to maintain system reliability.

Q. How did each of the three PLEXOS models work together to inform the economic analysis presented here?

A. In the first step, resource portfolios (with and without the Transmission Projects and associated wind resources) were developed using the LT model. The LT model operates by minimizing operating costs for existing and prospective new resources, subject to system load balance, reliability, and other constraints. Over the 20-year planning horizon, the model optimizes resource additions subject to resource costs and load constraints. These constraints include seasonal loads, operating reserves and regulation reserves plus a minimum capacity reserve margin for each load area represented in the model.

To accomplish these optimization objectives, the LT model performs a least-cost dispatch for existing and potential planned generation, while considering cost and performance of existing contracts and new demand-side management (DSM) alternatives within PacifiCorp's transmission system. Resource dispatch is based on representative data blocks for each of the 12 months of every year. Dispatch also determines optimal electricity flows between zones and includes spot market transactions for system balancing. The model minimizes the system PVRR, which includes the net present value cost of existing contracts, market purchase costs, market sale revenues, generation costs (fuel, fixed and variable operation and maintenance, decommissioning, emissions, unserved energy, and unmet capacity), costs of DSM resources, amortized capital costs for existing coal resources and potential new resources, and costs for potential transmission upgrades.

Each portfolio developed by the LT model must have sufficient capacity to be reliable over the IRP's 20-year planning horizon. The resource portfolios reflect a combination of planning assumptions such as resource retirements, CO_2 prices, wholesale power and natural gas prices, load growth net of assumed private generation penetration levels, cost and performance attributes of potential transmission upgrades, and new and existing resource cost and performance data, including assumptions for new supply-side resources and incremental DSM resources.

Q. What is the next step in the modeling process?

A. In the second step, the Company conducted a reliability assessment using the ST model. The ST model begins with a portfolio from the LT model that has not yet benefited from a reliability assessment conducted at an hourly level. The ST model is first run at an hourly level for 20 years to retrieve two critical pieces of data: (1) shortfalls by hour; and (2) the value of every potential resource to the system. This information is then used to determine the most cost-effective resource additions needed to meet reliability shortfalls, leading to a reliability-modified portfolio. The ST model is then run again with the modified portfolio to calculate an initial PVRR, which is risk-adjusted by outcomes of MT model stochastics that occurs in the third step of the process.

Q. Please describe how the MT model is used to conduct cost and risk analysis.

A. In the third step, the resource portfolios developed by the LT model and adjusted for reliability by the ST model are simulated in the MT model to produce metrics that support comparative cost and risk analysis among the different resource portfolio alternatives. The stochastic simulation in the MT model produces a dispatch solution that accounts for chronological commitment and dispatch constraints. The MT simulation incorporates stochastic risk in its production cost estimates by using the Monte Carlo sampling of stochastic variables, which include load, wholesale electricity and natural gas prices, hydro generation, and thermal unit outages. The MT results are used to calculate a risk adjustment, which is combined with ST model system costs to achieve a final risk-adjusted PVRR.

Q. Is the PLEXOS model appropriate for analyzing the customer benefits of the Transmission Projects?

A. Yes. The PLEXOS model is the appropriate modeling tool when evaluating significant capital investments that influence PacifiCorp's resource mix and affect least-cost dispatch of system resources. The LT model simultaneously and endogenously evaluates capacity and energy trade-offs associated with resource and transmission capital projects and is needed to understand how the type, timing, and location of future resources might be affected by the Transmission Projects. The ST and MT models provide additional granularity on how the Transmission Projects are projected to affect system operations while assessing stochastic risks. Together, the LT, MT, and ST models are best suited to perform a benefit analysis for the Transmission Projects that is consistent with long-standing least-cost, least-risk planning principles applied in PacifiCorp's IRP and resource procurement activities.

Q. When developing resource portfolios with the PLEXOS model, did you perform a reliability assessment?

A. Yes. As described above, the ST model was used to establish system costs for each portfolio over the entire 20-year planning period. The ST model accounts for resource availability and system requirements at an hourly level, producing reliability and resource value outcomes that will reveal whether an initially reliable portfolio selected by the LT model leaves shortfalls at an hourly level, which can then be addressed.

Q. Did PacifiCorp analyze how other assumptions affect its economic analysis of the Transmission Projects?

A. Yes. The economic analysis also included one sensitivity that quantified how changes in new resource capital costs for the two BTA wind projects and capital cost assumptions for the Transmission Projects influenced projected customer benefits.

Q. Company witness Vail's testimony indicates that the Transmission Projects will enable up to 2,030 MW of new resources to interconnect in eastern Wyoming. Why does your analysis only account for 1,640 MW?

A. The economic analysis reasonably accounted for only those wind resources that were selected to the 2020AS RFP final shortlist.

Q. Does PacifiCorp assume that all the up-front capital costs of the Transmission Projects will be paid by its retail customers?

A. No. The cost of the Transmission Projects will be shared between PacifiCorp's retail and wholesale transmission customers. In my analyses, I assumed retail customers would pay 80 percent of the revenue requirement from the up-front capital cost for the Transmission Projects, after accounting for an assumed 20 percent revenue credit from the Company's transmission customers.

E. Price-Policy Scenario Results

Q. Please summarize the PVRR(d) results calculated from the PLEXOS model.

A. Table 3 summarizes the PVRR(d) results for each price-policy scenario.[18]

Table 3. PVRR(d) (Benefit)/Cost of the Transmission Projects ($ million)

Price-Policy Scenario	PVRR(d)	Risk-Adjusted PVRR(d)
MM	($128)	($260)
LN	$755	$670
MN	$393	$289
HH	($932)	($1,100)
SCGHG	($2,568)	($2,819)

[18] Exhibit PAC/801 Transmission Projects Analysis.

As shown above, system costs increase when the Transmission Projects are removed from the portfolio in the MM, HH, and SCGHG price-policy scenarios. Conversely, costs decrease in the LN and MN price-policy scenarios. Without the Transmission Projects, emissions from PacifiCorp's generation resources increase considerably—ranging from 8.4 percent in the MN price-policy scenario to 17.8 percent in the SCGHG price-policy scenario. The LN and MN scenarios unrealistically fail to account for the risk that there will be some form of policy action taken to impute a cost or penalty on greenhouse gas emissions over the planning period. It is also unlikely gas prices will be suppressed for many decades to come, as assumed in the LN price-policy scenario. Further, cost-and-risk results indicate that there is a tremendous opportunity cost of not building the Transmission Projects should policies develop that impose costs on greenhouse gas emissions. This is seen with the disproportionate increase in costs under the HH and SCGHG price-policy scenarios relative to the size of cost reductions in the unlikely LN and MN price-policy scenarios.

Considering that the removal of the Transmission Projects increases system costs among the MM, HH, and SCGHG price-policy scenarios, significantly increases emissions and associated costs and risks, and significantly increases market-reliance risk (discussed further below), this analysis supports the necessity of the Transmission Projects and indicates that they are likely to result in robust customer benefits.

Q. Did you calculate how the PVRR(d) results presented above would change if you assumed the Transmission Projects would be required to provide service under all these interconnection and transmission service contracts?

A. Yes. This would increase the cost of the "alternative" to equal the cost of the Transmission Projects, which represents a $971 million increase in unavoidable capital relative to what is shown in the table above. This translates into $482 million on a PVRR basis. Table 4 shows the PVRR(d) results with this level of unavoidable capital. When this higher cost is applied to the results, the MN price-policy scenario now shows there are significant customer benefits from the Transmission Projects.

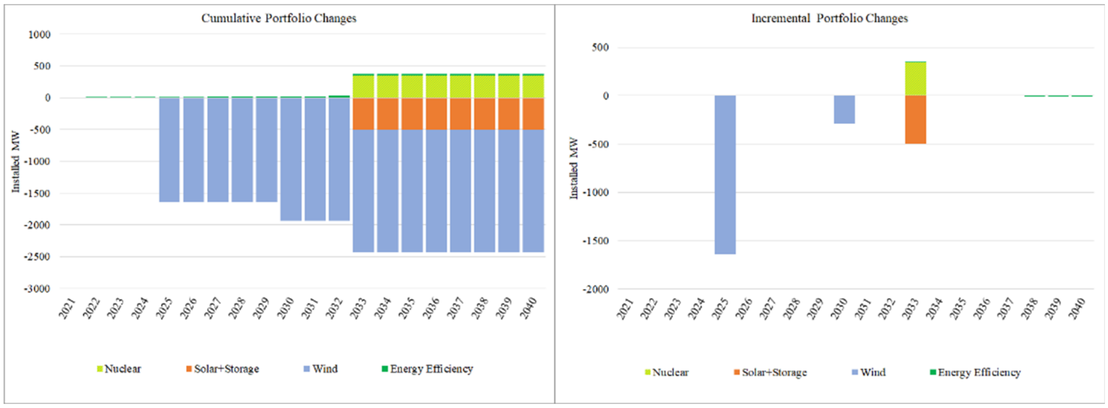
Table 4. PVRR(d) (Benefit)/Cost of the Transmission Projects Assuming the Transmission Projects are Unavoidable ($ million)

Price-Policy Scenario	PVRR(d)	Risk-Adjusted PVRR(d)
MM	($610)	($742)
LN	$273	$188
MN	($90)	($194)
HH	($1,414)	($1,582)
SCGHG	($3,050)	($3,301)

Q. Please describe the impact of removing the Transmission Projects and associated wind resources from the 2021 IRP's preferred portfolio.

A. Figure 3 shows the cumulative (at left) and incremental (at right) portfolio changes when the Transmission Projects are eliminated under the MM price-policy scenario. A positive value indicates an increase in resources and a negative value indicates a decrease in resources when the Transmission Projects are eliminated. Without the Transmission Projects, the 1,640 MW of wind resources selected in the 2020AS RFP are removed from the portfolio in 2024 (shown as a reduction in 2025, the first full year these resources would be online). An additional 289 MW of wind is eliminated in 2030. In 2034, the absence of the new wind resources triggers the addition of an advanced nuclear plant that displaces solar co-located with storage resources.

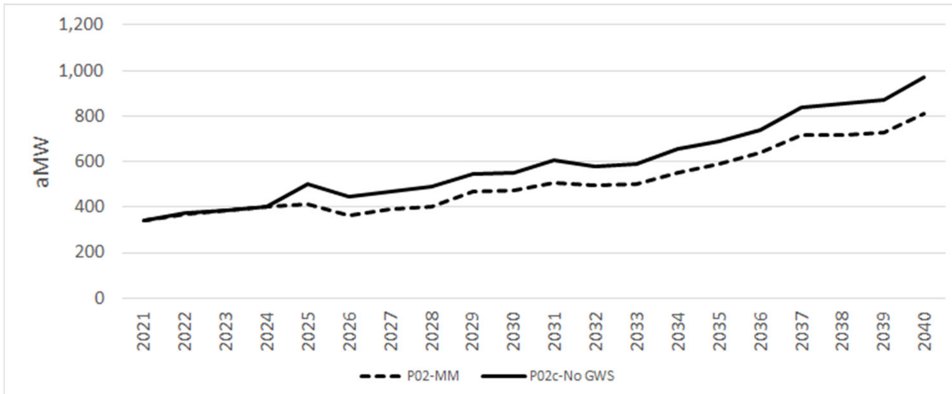
Figure 3. Changes in the Resource Portfolio without the Transmission Projects



Q. Does the removal of the Transmission Projects and associated wind resources increase the Company's reliance on market purchases?

A. Yes. Figure 4 shows how market purchases change when the Transmission Projects are removed from the portfolio under the MM price-policy scenario. With fewer resources, market purchases increase by nearly 20 percent on an annual basis. This creates higher risk as the Company is forced to rely on market purchases at a time when there are increasing resource adequacy concerns throughout the western interconnect. This increased market and reliability risk is not reflected in the PVRR(d) results.

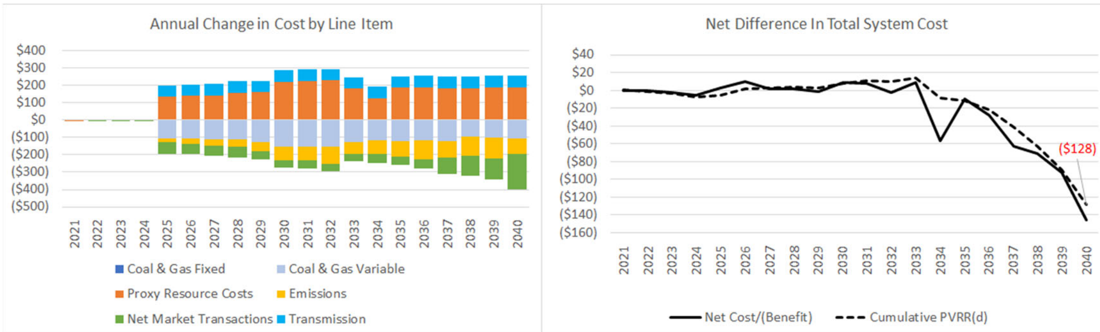
Figure 4. Changes in Market Purchases without the Transmission Projects



Q. How do system costs change with and without the Transmission Projects?

A. Figure 5 summarizes changes in system costs (conservatively assuming the cost for a 230-kV alternative is unavoidable), based on ST model results using MM price-policy assumptions, when the Transmission Projects are eliminated from the portfolio. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2040, the PVRR(d) shows that the portfolio without the Transmission Projects is $128 million higher cost than the portfolio with the Transmission Projects. On a risk-adjusted basis, which factors in the risk associated with low-probability, high-cost events through stochastic simulations, the portfolio without the Transmission Projects is $260 million higher cost than the portfolio with the Transmission Projects. The risk-adjusted results indicate that the Transmission Projects add significant risk mitigation benefits associated with volatility in market prices, loads, hydro generation, and unplanned outages.

Figure 5. Increase/(Decrease) in System Costs when the Transmission Projects are Removed from the Portfolio



Q. Is there incremental customer upside to the PVRR(d) results?

A. Yes. The PVRR(d) results presented in Table 4 do not reflect the potential value of RECs generated by the incremental energy output from the renewable projects enabled by the Transmission Projects. Customer benefits for all price-policy scenarios would improve by approximately $42 million for every dollar assigned to the incremental RECs that will be generated through 2040. Beyond potential REC-revenue benefits, the economic analysis of the Transmission Projects does not reflect the reliability benefits that these investments will provide to the transmission system, which are described by Company witness Vail.

Q. How do the risk-adjusted PVRR(d) results compare to the stochastic-mean PVRR(d) results?

A. The risk-adjusted PVRR(d) results show an increase in the benefits of the Transmission Projects when compared to the reported ST-model PVRR(d) results. This indicates that the Transmission Projects provide stochastic risk benefits by making the system less susceptible to low-probability combinations of load, market price, hydro generation, and thermal outage volatility that can increase system costs.

Q. Have you calculated how changes in the capital cost for the Transmission Projects might affect customer benefits?

A. Yes. A one percent increase in the initial capital costs associated with the Transmission Projects would reduce PVRR benefits by $4.8 million. This estimate conservatively assumes that there is no change in transmission costs that will be avoided with the construction of the Transmission Projects. In the MM price-policy scenario, capital costs for the Transmission Projects would need to increase by 54 percent to eliminate customer benefits on a risk-adjusted basis. This demonstrates that the projected customer benefits are robust to potential variations in capital costs for the Transmission Projects, particularly when considering that the cost estimates used in the economic analysis of the Transmission Projects reflect PacifiCorp's experience with the recent construction of Gateway West Segment D.2 and the associated 230-kV network upgrades reflecting current market conditions.

F. <u>Post-Construction Economic Review</u>

Q. Did you continue to revisit your economic analysis of the Transmission Projects after initiating construction?

A. Yes.

Q. Why did you continue to revisit your economic analysis?

A. After PacifiCorp provided its notice to proceed to begin constructing the Transmission Projects, the Company continued to negotiate contracts for the wind resources that are dependent on the Transmission Projects. During the pendency of those negotiations, there were two significant developments that affected the cost of the wind resources. Considering that the cost of the wind resources affects the economic analysis of the Transmission Projects, I continued to check that changes to costs did not erode customer benefits.

Q. Please describe the two developments that affected the cost of the wind resources dependent upon the Transmission Projects.

A. First, as the Company finalized contracts with resources selected to the 2020AS RFP final shortlist, national tariff policies, global supply-chain challenges, and inflationary pressures required that bidders secure higher prices than originally offered into the 2020AS RFP. Second, Congress passed the IRA that, among other things, provided an opportunity for the wind projects dependent upon the Transmission Projects to qualify for a 110 percent PTC, which is substantially higher than the 60 percent PTC assumed in my economic analysis that supported the Company's decision to begin constructing the Transmission Projects.

Q. How did you evaluate the impact of these developments on the economic analysis of the Transmission Projects?

A. As the Company finalized the wind resource contracts to capture price changes and new provisions related to the IRA, MM price-policy results were revisited so that we could understand how the economic analysis was being impacted. The updated analysis captured price changes in the contracts and incorporated updated energy values for projected wind energy using more current market price assumptions (*i.e.,* June 2022).

Q. Did your post-construction economic review capture other updates?

A. Yes. Due to the price pressures I discussed above, some of the 2020AS RFP final shortlist bidders were unwilling to offer any form of price update. These projects were removed from consideration. While this did not include any of the wind projects dependent on the Transmission Projects, the removal of bids increases the overall need for new resources. The updated analysis also included any new contracts that were executed outside of the 2020AS RFP process and incorporated the most current load forecast, which was developed in May 2022. The updated analysis also accounted for the potential impact of the OTR.

Q. What did you find when you prepared this post-construction economic review of the Transmission Projects?

A. This on-going review continued to show that the Transmission Projects are expected to generate customer benefits. The last of these reviews, prepared in September 2022, reflected updated pricing for all wind resource PPAs dependent upon the Transmission Projects and showed risk-adjusted customer benefits totaling $247 million in the MM price-policy scenario. This is similar to the comparable risk-adjusted customer benefits totaling $260 million from the economic analysis in place when the Company initiated construction of the Transmission Projects.

IV. CONCLUSION

Q. Please summarize the conclusions of your Gateway South and Gateway West testimony.

A. PacifiCorp's analysis shows that the Transmission Projects are necessary and in the public interest. Under the MM price-policy scenario, the Transmission Projects produce significantly lower total system costs—ranging from $128 to $260 million when using the most conservating assumptions for avoided transmission and ranging from $610 million to $742 million when assuming the Transmission Projects are unavoidable. The Transmission Projects are also lower risk than alternative scenarios without the resources. Most notably, without the Transmission Projects and accompanying wind resources, the Company is forced to rely heavily on market purchases to serve load, which increases risk related to market volatility and creates reliability concerns given the region's well established resource adequacy concerns. By proactively constructing the Transmission Projects the Company can not only save customers money (as evidenced by the savings in the MM price-policy scenario) but also reduce customer risk, which is a non-quantifiable benefit that strongly favors the Transmission Projects. The updated economic analysis of the Transmission Projects demonstrates that net benefits more than outweigh net project costs.

Q. What do you recommend?

A. As supported by PacifiCorp's economic analysis, I recommend that the Commission determine that Company's decisions to invest in the Transmission Projects are prudent and reasonable.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 433
Exhibit PAC/801
Witness: Rick T. Link

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Rick T. Link

Transmission Projects Analysis

February 2024

Estimated Annual Revenue Requirement Results ($ million)

Medium Gas, Medium CO2

(Benefit) /Cost	*PVRR(d)*	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Cost of Project	$1,837	$0	$0	$0	$0	$193	$194	$199	$214	$217	$225	$231	$234	$240	$238	$298	$301	$298	$300	$304	$309
New Wind Capital Cost	$397	$0	$0	$0	$0	$33	$34	$34	$40	$40	$42	$45	$45	$47	$51	$93	$94	$94	$95	$97	$99
Wind Run-Rate Fixed Costs	$327	$0	$0	$0	$0	$51	$51	$54	$53	$55	$56	$57	$59	$59	$56	$16	$17	$17	$17	$17	$17
PPA	$1,332	$0	$0	$0	($0)	$180	$181	$188	$197	$202	$208	$215	$220	$224	$220	$130	$132	$129	$129	$132	$134
PTC Credits	($748)	$0	$0	$0	$0	($130)	($130)	($135)	($134)	($139)	($140)	($143)	($148)	($148)	($148)	$0	$0	$0	$0	$0	$0
Wind Tax	$14	$0	$0	$0	$0	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2
Transmission GWS	$1,261	$0	$0	$0	$0	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138
Transmission D.1	$185	$0	$0	$0	$0	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20
Avoided Transmission - Base 230 kV	($843)	$0	$0	$0	$0	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)
Transmisison Network Wind	$41	$0	$0	$0	$0	$5	$5	$5	$5	$4	$4	$4	$4	$4	$4	$5	$4	$4	$4	$4	$4
Transmission OATT Credit	($129)	$0	$0	$0	($0)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)
Change in NPC	($1,345)	($0)	$0	($1)	($2)	($170)	($158)	($166)	($175)	($175)	($189)	($198)	($193)	($163)	($169)	($171)	($171)	($212)	($211)	($222)	($306)
Change in Emissions	($488)	$0	$0	$0	$0	($25)	($32)	($36)	($41)	($49)	($82)	($80)	($99)	($71)	($76)	($87)	($107)	($95)	($105)	($120)	($91)
Change in VOM & Driver Adjustments	($40)	($0)	$0	$0	($0)	($5)	($5)	($5)	($3)	($3)	($3)	($3)	($3)	$34	($16)	($16)	($16)	($16)	($16)	($16)	($17)
Change in DSM	($41)	$0	($1)	($2)	($3)	($3)	($3)	($4)	($5)	($5)	($5)	($5)	($6)	($5)	($5)	($5)	($6)	($6)	($6)	($6)	($6)
Change in Deficiency	($4)	($0)	$0	$0	($1)	($3)	$0	($1)	($2)	($0)	$0	$0	$0	$0	$0	$0	$1	($0)	$0	$0	$0
Change in System Fixed Cost	($48)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	$48	$49	$49	($40)	($41)	($42)	($43)	($45)	($46)	($48)	($49)
Net (Benefit) /Cost	($128)	($0)	($1)	($2)	($6)	($12)	($4)	($12)	($12)	($16)	($5)	($6)	($17)	($5)	($70)	($24)	($42)	($76)	($85)	($107)	($160)
Risk Adjustment	($132)																				
Net (Benefit) /Cost with Risk Adjustment	($260)																				

Medium Gas, No CO2

(Benefit) /Cost	*PVRR(d)*	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Cost of Project	$1,811	$0	$0	$0	$0	$194	$195	$201	$215	$217	$225	$231	$234	$240	$167	$297	$301	$298	$300	$304	$309
New Wind Capital Cost	$398	$0	$0	$0	$0	$34	$35	$34	$40	$40	$42	$45	$45	$47	$51	$93	$94	$94	$95	$97	$99
Wind Run-Rate Fixed Costs	$326	$0	$0	$0	$0	$50	$50	$54	$52	$55	$56	$57	$59	$59	$56	$16	$17	$17	$17	$17	$17
PPA	$1,304	$0	$0	$0	($0)	$180	$181	$188	$197	$202	$208	$215	$220	$224	$149	$130	$132	$129	$129	$132	$134
PTC Credits	($746)	$0	$0	$0	$0	($129)	($129)	($134)	($134)	($139)	($140)	($143)	($148)	($148)	($148)	$0	$0	$0	$0	$0	$0
Wind Tax	$14	$0	$0	$0	$0	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2
Transmission GWS	$1,261	$0	$0	$0	$0	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138
Transmission D.1	$185	$0	$0	$0	$0	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20
Avoided Transmission - Base 230 kV	($843)	$0	$0	$0	$0	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)
Transmisison Network Wind [1]	$41	$0	$0	$0	$0	$5	$5	$5	$5	$4	$4	$4	$4	$4	$4	$5	$4	$4	$4	$4	$4
Transmission OATT Credit	($129)	$0	$0	$0	($0)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)
Change in NPC	($1,305)	$1	$0	($1)	($1)	($163)	($163)	($168)	($171)	($172)	($202)	($197)	($203)	($150)	($152)	($153)	($167)	($190)	($202)	($215)	($251)
Change in Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in VOM & Driver Adjustments	($49)	($0)	($0)	$0	($0)	($7)	($8)	($8)	($4)	($4)	($4)	($4)	($4)	$34	($16)	($17)	($17)	($17)	($17)	($17)	($16)
Change in DSM	($41)	$0	($1)	($2)	($3)	($3)	($3)	($4)	($5)	($5)	($5)	($5)	($6)	($5)	($5)	($5)	($6)	($6)	($6)	($6)	($6)
Change in Deficiency	($4)	($0)	$0	$0	($1)	($3)	($0)	($1)	($1)	$0	($0)	$0	$0	($0)	$0	$0	($1)	$0	$0	$0	$0
Change in System Fixed Cost	($20)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	$48	$49	$49	($40)	$30	($42)	($43)	($45)	($46)	($48)	($49)
Net (Benefit) /Cost	$393	$0	($1)	($2)	($5)	$18	$21	$19	$33	$36	$62	$74	$70	$80	$23	$80	$68	$39	$28	$20	($12)
Risk Adjustment	($104)																				
Net (Benefit) /Cost with Risk Adjustment	$289																				

Estimated Annual Revenue Requirement Results ($ million)

High Gas, High CO2

(Benefit) /Cost	*PVRR(d)*	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Cost of Project	$1,808	$0	$0	$0	$0	$193	$194	$199	$214	$217	$225	$231	$234	$240	$167	$298	$301	$298	$300	$304	$309
New Wind Capital Cost	$396	$0	$0	$0	$0	$33	$34	$34	$40	$40	$42	$45	$45	$47	$51	$93	$94	$94	$95	$97	$99
Wind Run-Rate Fixed Costs	$327	$0	$0	$0	$0	$51	$51	$54	$53	$55	$56	$57	$59	$59	$56	$16	$17	$17	$17	$17	$17
PPA	$1,304	$0	$0	$0	($0)	$180	$181	$188	$197	$202	$208	$215	$220	$224	$149	$130	$132	$129	$129	$132	$134
PTC Credits	($749)	$0	$0	$0	$0	($131)	($131)	($135)	($134)	($139)	($140)	($143)	($148)	($148)	($148)	$0	$0	$0	$0	$0	$0
Wind Tax	$14	$0	$0	$0	$0	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2
Transmission GWS	$1,261	$0	$0	$0	$0	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138
Transmission D.1	$185	$0	$0	$0	$0	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20
Avoided Transmission - Base 230 kV	($843)	$0	$0	$0	$0	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)
Transmisison Network Wind	$41	$0	$0	$0	$0	$5	$5	$5	$5	$4	$4	$4	$4	$4	$4	$5	$4	$4	$4	$4	$4
Transmission OATT Credit	($129)	$0	$0	$0	($0)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)
Change in NPC	($1,697)	$0	$1	$1	($4)	($185)	($183)	($199)	($217)	($206)	($232)	($241)	($259)	($217)	($211)	($237)	($233)	($269)	($346)	($349)	($339)

Change in Emissions	($936)	$0	$0	$0	$0	($71)	($79)	($86)	($84)	($109)	($160)	($161)	($169)	($125)	($153)	($150)	($186)	($188)	($130)	($170)	($203)
Change in VOM & Driver Adjustments	($37)	($0)	$0	$0	$0	($3)	($3)	($3)	($3)	($3)	($2)	($2)	($3)	$34	($16)	($16)	($16)	($17)	($17)	($19)	($18)
Change in DSM	($41)	$0	($1)	($2)	($3)	($3)	($3)	($4)	($5)	($5)	($5)	($5)	($6)	($5)	($5)	($5)	($6)	($6)	($6)	($6)	($6)
Change in Deficiency	($8)	($3)	$0	$0	($1)	($3)	$0	($1)	($3)	$0	($0)	($0)	($2)	($0)	($0)	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	($20)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	$48	$49	$49	($40)	$30	($42)	($43)	($45)	($46)	($48)	($49)
Net (Benefit) /Cost	($932)	($3)	($1)	($1)	($8)	($72)	($75)	($95)	($98)	($106)	($125)	($130)	($154)	($113)	($189)	($154)	($183)	($227)	($246)	($287)	($306)
Risk Adjustment	($168)																				
Net (Benefit) /Cost with Risk Adjustment	($1,100)																				

Low Gas, No CO2

(Benefit) /Cost	*PVRR(d)*	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Cost of Project	$1,838	$0	$0	$0	$0	$194	$195	$200	$214	$217	$225	$231	$234	$240	$238	$298	$301	$298	$300	$304	$309
New Wind Capital Cost	$397	$0	$0	$0	$0	$34	$34	$34	$40	$40	$42	$45	$45	$47	$51	$93	$94	$94	$95	$97	$99
Wind Run-Rate Fixed Costs	$326	$0	$0	$0	$0	$51	$51	$54	$53	$55	$56	$57	$59	$59	$56	$16	$17	$17	$17	$17	$17
PPA	$1,332	$0	$0	$0	($0)	$180	$181	$188	$197	$202	$208	$215	$220	$224	$220	$130	$132	$129	$129	$132	$134
PTC Credits	($748)	$0	$0	$0	$0	($130)	($130)	($134)	($134)	($139)	($140)	($143)	($148)	($148)	($148)	$0	$0	$0	$0	$0	$0
Wind Tax	$14	$0	$0	$0	$0	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2
Transmission GWS	$1,261	$0	$0	$0	$0	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138
Transmission D.1	$185	$0	$0	$0	$0	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20
Avoided Transmission - Base 230 kV	($843)	$0	$0	$0	$0	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)
Transmisison Network Wind [1]	$41	$0	$0	$0	$0	$5	$5	$5	$5	$4	$4	$4	$4	$4	$4	$5	$4	$4	$4	$4	$4
Transmission OATT Credit	($128.78)	$0.00	$0.00	$0.00	($0.07)	($14.19)	($14.17)	($14.14)	($14.13)	($14.11)	($14.10)	($14.08)	($14.06)	($14.05)	($14.04)	($14.14)	($14.12)	($14.10)	($14.08)	($14.07)	($14.06)
Change in NPC	($948)	($0)	$0	$0	($2)	($105)	($109)	($115)	($120)	($119)	($141)	($141)	($147)	($118)	($123)	($122)	($130)	($151)	($159)	($165)	($200)
Change in Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in VOM & Driver Adjustments	($40)	$0	$0	$0	$0	($4)	($5)	($6)	($3)	($2)	($2)	($3)	($3)	$34	($17)	($17)	($17)	($17)	($17)	($17)	($17)
Change in DSM	($41)	$0	($1)	($2)	($3)	($3)	($3)	($4)	($5)	($5)	($5)	($5)	($6)	($5)	($5)	($5)	($6)	($6)	($6)	($6)	($6)
Change in Deficiency	($5)	($0)	$0	$0	($2)	($3)	($0)	($1)	($2)	($0)	($0)	$0	$0	($0)	$0	($0)	($0)	$0	$0	$0	$0
Change in System Fixed Cost	($48)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	$48	$49	$49	($40)	($41)	($42)	($43)	($45)	($46)	($48)	($49)
Net (Benefit) /Cost	$755	($0)	($1)	($2)	($6)	$79	$77	$74	$84	$90	$125	$132	$128	$111	$52	$111	$105	$79	$72	$69	$38
Risk Adjustment	($85)																				
Net (Benefit) /Cost with Risk Adjustment	$670																				

SC-GHG

(Benefit) /Cost	*PVRR(d)*	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Cost of Project	$1,836	$0	$0	$0	$0	$192	$194	$199	$214	$217	$225	$231	$234	$240	$238	$298	$301	$298	$300	$304	$309
New Wind Capital Cost	$396	$0	$0	$0	$0	$33	$34	$34	$40	$40	$42	$45	$45	$47	$51	$93	$94	$94	$95	$97	$99
Wind Run-Rate Fixed Costs	$328	$0	$0	$0	$0	$51	$52	$54	$53	$55	$56	$57	$59	$59	$56	$16	$17	$17	$17	$17	$17
PPA	$1,332	$0	$0	$0	($0)	$180	$181	$188	$197	$202	$208	$215	$220	$224	$220	$130	$132	$129	$129	$132	$134
PTC Credits	($750)	$0	$0	$0	$0	($131)	($131)	($135)	($134)	($139)	($140)	($143)	($148)	($148)	($148)	$0	$0	$0	$0	$0	$0
Wind Tax	$14	$0	$0	$0	$0	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2
Transmission GWS	$1,261	$0	$0	$0	$0	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138	$138
Transmission D.1	$185	$0	$0	$0	$0	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20
Avoided Transmission - Base 230 kV	($843)	$0	$0	$0	$0	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)	($92)
Transmisison Network Wind	$41	$0	$0	$0	$0	$5	$5	$5	$5	$4	$4	$4	$4	$4	$4	$5	$4	$4	$4	$4	$4
Transmission OATT Credit	($129)	$0	$0	$0	($0)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)	($14)
Change in NPC	($2,129)	$0	($1)	($6)	($4)	($217)	($230)	($243)	($260)	($296)	($363)	($350)	($357)	($286)	($288)	($292)	($304)	($380)	($270)	($291)	($359)
Change in Emissions	($1,919)	($0)	$3	$5	($3)	($317)	($264)	($266)	($245)	($246)	($286)	($286)	($296)	($198)	($218)	($229)	($260)	($257)	($274)	($274)	($260)
Change in VOM	($30)	$0	($0)	$0	$0	($1)	($1)	($2)	($2)	($2)	($1)	($2)	($2)	$35	($16)	($16)	($15)	($22)	($15)	($14)	($17)
Change in DSM	($41)	$0	($1)	($2)	($3)	($3)	($3)	($4)	($5)	($5)	($5)	($5)	($6)	($5)	($5)	($5)	($6)	($6)	($6)	($6)	($6)
Change in Deficiency	($236)	($0)	$0	($15)	($3)	($67)	($38)	($16)	($25)	($4)	($126)	$0	$0	$0	($0)	$0	($1)	($233)	$0	$0	$69
Change in System Fixed Cost	($48)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	$48	$49	$49	($40)	($41)	($42)	($43)	($45)	($46)	($48)	($49)
Net (Benefit) /Cost	($2,568)	($1)	$1	($18)	($13)	($412)	($343)	($331)	($322)	($336)	($508)	($363)	($377)	($254)	($331)	($287)	($328)	($646)	($312)	($328)	($312)
Risk Adjustment	($251)																				
Net (Benefit) /Cost with Risk Adjustment	($2,819)																				

REDACTED
Docket No. UE 433
Exhibit PAC/900
Witness: Thomas R. Burns

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Direct Testimony of Thomas R. Burns

February 2024

TABLE OF CONTENTS

ATTACHED EXHIBITS

I. INTRODUCTION AND QUALIFICATIONS

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

A. My name is Thomas R. Burns, my business address is 825 NE Multnomah Street, Suite LCT 600, Portland, Oregon 97232. I am currently employed as Vice President of Resource Planning and Acquisitions for PacifiCorp.

Q. Please describe your education and professional experience.

A. I graduated from Illinois State University with a Bachelor of Science degree in Economics. I joined PacifiCorp in 2007 and assumed the responsibilities of my current position in September 2022. Over this period, I held several operational, analytical and leadership positions within the Company. My previous role with PacifiCorp was Director of Energy Supply Management, Operations, and Reliability. In that role I was instrumental in the design and implementation of the Western Energy Imbalance Market.

Q. Briefly describe the responsibilities of your current position.

A. I am responsible for aspects of PacifiCorp's resource planning and procurement functions, which include the integrated resource plan (IRP), structured commercial business and valuation activities, and long-term load forecasts. Most relevant to this general rate case, I oversee the planning, analysis, and outreach processes that are used to develop PacifiCorp's IRP, and the economic analysis that helps guide the Company's resource acquisitions.

II. PURPOSE OF TESTIMONY

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

A. I provide economic analysis that supports PacifiCorp's decisions to:

- Convert Jim Bridger Units 1 and 2 to natural gas operations;
- Acquire the 190-megawatt (MW) Rock Creek I wind facility; and
- Acquire and repower the 49 MW Rock River I wind facility in Wyoming.

I also summarize PacifiCorp's assessment of the projects from the 2021 IRP and IRP Update, and discuss customer benefits that result from these projects.

Q. Please provide an overview of your testimony on Jim Bridger Units 1 and 2.

A. My economic analyses indicate that converting Jim Bridger Units 1 and 2 to natural gas is in the public interest and will generate benefits for Oregon customers. Compared to early retirement of Jim Bridger Units 1 and 2, natural gas conversion has a present-value revenue requirement differential (PVRR(d)) customer benefit ranging from $271.68 million to $656.41 million. The range of benefits depends on the timing and magnitude of early coal unit retirement assumptions.

These substantial customer benefits are expected because the conversion is anticipated to cost approximately $34.6 million on a total-Company basis, and $9.3 million Oregon-allocated. While the assumed operational life of a new gas peaking asset is longer than the assumed life of Jim Bridger Units 1 and 2 once converted to gas-fueled generating units, the upfront capital required to convert to natural gas is significantly less than installing a new gas-fired generating unit. The Jim Bridger gas conversions are a significant opportunity to maintain much needed system capacity at a very low cost, during a period when there are growing resource adequacy concerns throughout the region.

Q. Please provide an overview of your testimony for Rock Creek I.

A. My economic analyses indicate that the project is in the public interest and will generate benefits for Oregon customers, and that Rock Creek I is expected to provide customer benefits in all scenarios. Analysis prepared before the Inflation Reduction Act (IRA) showed $15 million of customer benefits, which increased to $20 million of benefits on a risk-adjusted basis under a medium natural gas prices paired with medium carbon dioxide (CO_2) prices (MM) price-policy scenario. The post-IRA analysis of both Rock Creek I and Rock Creek II, a co-located sister facility not included in this proceeding due to its later in-service date, yields customer benefits totaling $298 million, that rise to $318 million on a risk-adjusted basis under an MM price-policy scenario. Conservatively, these benefits do not assign any value to the renewable energy certificates (RECs) that will be generated by Rock Creek I, which can provide additional customer benefits if sold, transferred, or used to comply with relevant state requirements.

Q. Please provide an overview of your testimony for Rock River I.

A. My economic analyses indicate that the project is in the public interest and will generate benefits for Oregon customers. Customer benefits for Rock River I range from $30.15 million when using medium natural gas and medium CO_2 assumptions to $67.76 million for high natural gas and high CO_2 assumptions before adjusting for the IRA. When factoring in the IRA, these benefits increased to $54.09 million when using medium natural gas and medium CO_2 assumptions and $91.69 million for high natural gas and high CO_2 assumptions. Conservatively, these benefits do not assign any value to the RECs that will be generated by Rock River I, which can provide additional customer benefits if sold, transferred, or used to comply with relevant state requirements.

III. JIM BRIDGER UNITS 1 AND 2 NATURAL GAS CONVERSION

Q. Please describe the conversion of Jim Bridger Units 1 and 2 to natural gas.

A. As described in the testimony of Company witness Brad D. Richards, Exhibit PAC/1300, PacifiCorp is converting the Company's coal-fired Jim Bridger Units 1 and 2, located near Point of Rocks, Wyoming, to run on natural gas. The units were offline by January 2024, and are expected to be converted to natural gas and in service April 2024.

A. <u>Need</u>

Q. Please provide an overview of the Company's IRP process.

A. PacifiCorp's IRP process uses thorough analysis and modeling that measures cost and risk to develop the Company's plans to provide reliable and reasonably priced service for its customers. The primary objective of the IRP is to identify the least-cost, least--risk portfolio of resources to serve customers in the future. This "preferred portfolio" is the portfolio that can be delivered through specific action items at a reasonable cost and with manageable risks.

The Company completes an IRP cycle every two years (odd-numbered years), which includes preparing a full IRP every two years and an update to the full IRP in the off years (even-numbered years). The Company submits both its IRP and IRP Update to each of the six regulatory commissions in the states where the Company provides retail service. Each IRP is developed through an open and public process, with input from an active and diverse group of stakeholders, including state regulatory commissions, state consumer-advocacy departments, customer-sponsored advocacy groups, environmental-advocacy groups, resource-advocacy groups, independent-power producers, project developers, other utilities, and customers. During the public-input process, which typically spans at least a full year before the release of a full IRP, PacifiCorp holds regular meetings with stakeholders to solicit feedback on the Company's planning assumptions, methodologies, and model results.

Q. Did the Company's 2021 IRP identify a need for additional resources to serve PacifiCorp's customers?

A. Yes. The primary focus of any IRP is to forecast the need for resources and evaluate different strategies to meet that need over time. The Company's 2021 IRP shows that PacifiCorp has a capacity deficit in all years of the planning horizon—starting at 1,071 MW in 2021 and increasing to over 6,600 MW by 2040. In 2025, the resource need in the 2021 IRP is 1,627 MW. As described further below, this need has increased since the 2021 IRP was finalized.

Q. How does the 2021 IRP preferred portfolio address the need for new resources?

A. The 2021 IRP preferred portfolio represents PacifiCorp's least-cost, least-risk plan to reliably meet customer demand over a 20-year planning period. Using a range of cost and risk metrics to evaluate numerous resource portfolios, PacifiCorp selected a preferred portfolio that reflects a cost-conscious plan that includes near-term investments in renewable resources that can capture tax credits before they expire or decrease and new transmission infrastructure to facilitate the interconnection and delivery of these resources. These new resources and transmission investments are lower cost than other resource and transmission alternatives and are necessary to reliably serve our customers.

Q. Can you describe the methodology that PacifiCorp used in the 2021 IRP to analyze the economics of its coal units and derive the preferred portfolio?

A. Yes. PacifiCorp incorporated a new and more advanced optimization modeling system called PLEXOS. The PLEXOS modeling system provides three platforms (referred to as Long-term (LT), Medium-term (MT) and Short-term (ST)), which work on an integrated basis to inform the optimal combination of resources by type, timing, size, and location over PacifiCorp's 20-year planning horizon. Please refer to Company witness Rick T. Link's testimony for additional detail regarding PLEXOS and the LT, MT, and ST platforms.

Q. Has the Company prepared an update to the 2021 IRP?

A. Yes. On March 31, 2022, the Company issued its 2021 IRP Update.[1]

Q. What is the purpose of the 2021 IRP Update?

A. The IRP update is a checkpoint on the 2021 IRP action plan, and ensures that changes in the planning environment are considered between the two-year IRP planning cycle. The 2021 IRP Update assessed whether evolving trends and events impact customers and required changes to the action plan to deliver resources and transmission investments. Relevant here, the 2021 IRP Update reflects resource planning and procurement activities that occurred since the 2021 IRP, and present an updated load-and-resource balance and an updated resource portfolio.

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[1] PacifiCorp 2021 Integrated Resource Plan Update (Mar. 31, 2022) (https://www.pacificorp.com/energy/integrated-resource-plan.html).

Q. Did the 2021 IRP Update continue to show a need for additional generation resources?

A. Yes. As discussed in Company witness Link's testimony, the need increased due to an increase in forecast load. The 2021 IRP Update shows a resource need in all years of the planning horizon—starting at 1,584 MW in 2022 and increasing to 6,755 MW in 2040. In 2025, the resource need is 1,867 MW, an increase of 240 MW, or approximately 15 percent, relative to the resource need identified in the 2021 IRP. The higher load reflected in the 2021 IRP Update approaches the level analyzed in the high-load sensitivity conducted in the 2021 IRP. The most recent load forecast is even higher than that assumed in the 2021 IRP Update.

Moreover, now that the 2020 All-Source Request for Proposals (2020AS RFP) has ended, PacifiCorp was unable to execute firm contracts with all projects on the final shortlist. Due to national tariff policies, global supply-chain issues, and inflationary pressures, some projects on the 2020AS RFP final shortlist were unable to move forward. Consequently, PacifiCorp's procurement was reduced by 902 MW of solar resources and 497 MW of battery storage resources. This under-procurement adds to our need for new resources.

Q. Did PacifiCorp's preferred portfolio of resources in the Company's 2021 IRP include the Jim Bridger conversion?

A. Yes. In the 2021 IRP, the Company evaluated a number of scenarios specific to the valuation of Jim Bridger Units 1 and 2 that excluded and included the conversion of these units to natural gas fueled operation. The Company concluded that the portfolio that eliminated gas conversion of Jim Bridger Units 1 and 2 was significantly higher cost than the portfolio that included its inclusion across each of the price-policy scenarios,[2] and included the resources as part of the least-cost, least-risk 2021 IRP preferred portfolio.[3]

Q. Please describe key factors for including the Jim Bridger conversion in the 2021 IRP preferred portfolio.

A. The Company evaluated several alternatives, including the addition of new renewable generation resources, alternative coal unit retirement timing, regional haze compliance operating limits, and gas conversions or installation of carbon capture, utilization and storage. On a risk-adjusted basis, the portfolio without natural gas conversion of Jim Bridger Units 1 and 2 results in approximately $469 million higher costs than the preferred portfolio.

Q. Did the Commission acknowledge the Jim Bridger conversion in the 2021 IRP?

A. Yes.[4]

Q. Was the Jim Bridger conversion included in the 2021 IRP Update?

A. Yes. The conversion of Jim Bridger Units 1 and 2 were included in the preferred portfolio identified in the 2021 IRP Update.[5] This is consistent with the substantial and increased need for additional generation resources first identified in the 2021 IRP, and then confirmed in the 2021 IRP Update.

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[2] PacifiCorp 2021 IRP, Vol. 1, at 270 (Sept. 1, 2021) (https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2021-irp/Volume%20I%20-%209.15.2021%20Final.pdf).
[3] *Id.* at Ch. 1 Action Plan, Action Item 1c, at 24.
[4] Order No. 22-178, at 7 (May 23, 2022).
[5] PacifiCorp 2021 IRP Update, Ch. 7 Action Plan Status update, Action Item 1c, at 98 (https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2021_IRP_Update.pdf).

B. Modeling Assumptions

Q. Please summarize the natural gas and CO_2 price assumptions used in the economic analysis for Jim Bridger.

A. The economic analysis of Jim Bridger included five different price policy-scenarios—medium natural gas prices paired with medium CO_2 prices (MM); low natural gas prices without a CO_2 price (LN); medium natural gas prices without a CO_2 price (MN); high natural gas prices paired with high CO_2 prices (HH); and under medium gas prices and the social cost of greenhouse gases (SCGHG). While the MM price-policy scenario represents the Company's "expected case" describing likely future conditions, the additional scenarios provide additional helpful analyses.

These assumptions can influence the value of system energy, the dispatch of system resources, and PacifiCorp's resource mix. Consequently, wholesale-power prices and CO_2 policy assumptions affect net-power cost (NPC) benefits, non-NPC variable-cost benefits, and system fixed-cost benefits associated with the natural-gas conversion. Because wholesale power prices and CO_2 policy outcomes are both uncertain and important drivers to the economic analysis, it is important to evaluate a range of assumptions for these variables. The natural gas and CO_2 price assumptions are summarized in Table 1.

Table 1. Jim Bridger Price-Policy Assumptions

Price-Policy Scenario	Henry Hub Natural Gas Price (Levelized $/MMBtu)*	CO_2 Price Description
MM	$4.44	$9.93/ton starting in 2025 rising to $57.94/ton in 2040
LN	$2.94	None
MN	$4.44	None
HH	$5.64	$22.57/ton starting in 2025 rising to $102.48/ton in 2040
SCGHG	$4.44	$74.10/ton starting 2021 rising to $150.38/ton in 2040
*Nominal levelized Henry Hub natural gas price from 2025 through 2040.		

Q. Please describe the natural-gas price assumptions used in the price-policy scenarios.

A. The medium natural gas price assumptions are from PacifiCorp's official forward price curve (OFPC) dated March 31, 2021, which was the most current OFPC available when the modeling inputs were developed. The first 36 months of the OFPC reflect market forwards at the close of a given trading day, April 2021 is the prompt month in this analysis. As such, these 36 months are market forwards as of May 2021. The blending period (months 37 through 48) is calculated by averaging the month-on-month market forwards from the prior year with the month-on-month fundamentals-based price from the subsequent year. The fundamentals portion of the natural gas OFPC reflects Aurora-forecast prices.

Q. Please describe the CO_2 price assumptions used in the price-policy scenarios.

A. PacifiCorp used four different CO_2 price scenarios—zero, medium, high, and a price forecast that aligns with the SCGHG. The medium and high scenarios are derived from a survey of third-party industry experts, including IHS CERA, and Wood

Mackenzie and the Energy Information Administration as well as CO_2 price assumptions used by peer utilities. Both scenarios apply a CO_2 price as a tax beginning 2025. PacifiCorp incorporated the SCGHG that is assumed to start in 2021, and the SCGHG price is reflected in market prices and dispatch costs for the purposes of developing each portfolio (i.e., incorporated into capacity expansion optimization modeling).

Q. How did PacifiCorp pair the natural gas and CO_2 price assumptions for purposes of its analysis of Jim Bridger?

A. Scenarios pairing medium gas prices with alternative CO_2 price assumptions reflect OFPC forwards through April 2024 before transitioning to a fundamentals forecast. Scenarios using high or low gas prices, regardless of CO_2 price assumptions, do not incorporate any market forwards because these scenarios are designed to reflect an alternative view to that of the market. As such, the low and high natural gas price scenarios are purely fundamental forecasts. Low and high natural gas price scenarios are also derived from expert third-party, multi-client "off-the-shelf" subscription services.

Q. Does including potential future CO_2 costs reflect prudent utility planning?

A. Yes. The Company's price-policy scenarios include varying levels of assumed CO_2 costs to reflect the fact it is more likely than not that some policy will exist that will drive reduced emissions over the life of Jim Bridger. When determining CO_2 costs used for planning purposes, the Company strives to ensure that it is not an outlier as discussed above, and the medium price is within a reasonable range used by the industry to assess risk and conduct prudent resource planning. The most recent example of this trend is the Environmental Protection Agency's (EPA) proposed Ozone Transport Rule (OTR) restricting nitrogen oxide (NO_X) emissions from power plants and other industrial sources. At the time the Company conducted its economic analyses for the, this rule would have imposed new environmental compliance obligations beginning in 2023 and 2024 on coal units in Utah and Wyoming, respectively, with more severe limitations applicable in both states by 2026.[6]

Q. Are the modeled CO_2 costs intended to represent a literal carbon tax?

A. No. The modeled CO_2 costs are not intended to explicitly account for a future tax on CO_2 emissions. Rather, these costs capture the effect of policies incentivizing reduced emissions through benefits or imposing costs through penalties or other costs resulting from market dynamics driving the need for zero-emission resources or customer preferences.

Q. How were these portfolios examined for economic viability?

A. The Company's five price-policy scenarios were analyzed to provide a deterministic PVRR(d), a risk-adjusted PVRR(d), and the levelized benefits or costs of Jim Bridger Units 1 and 2 on a dollar-per-megawatt-hour ($/MWh) basis. These price-policy scenarios are discussed below.

C. <u>Price-Policy Scenario Results</u>

Q. Please summarize the PVRR(d) and levelized results for Jim Bridger Units 1 and 2.

A. Table 2 summarizes the PVRR(d) between cases, with and without Jim Bridger Units

[6] While these requirements are now subject to further federal litigation and subsequent agency review (s*ee, e.g., Wyoming, et al., v. United States Environmental Protection Agency, et al.,* 78 F4th 1171 (10th Cir. 2023) (OTR vacated and remanded in part); *Utah, et al., v. United States Environmental Protection Agency, et al.,* No. 23-9509 (Jul. 27, 2023) (staying OTR until final resolution for Utah)), the Company's economic analyses reflects then-current assumptions that the OTR would be in effect.

1 and 2.[7]

Table 2. Jim Bridger Units 1 and 2 (Benefits)/Costs

Price-Policy Scenario	PVRR(d) Net (Benefit)/Cost	Net Benefit ($/MWh)
MM	($515.20)	$321.79
MN	($595.67)	$609.59
LN	($656.41)	$174.87
HH	($378.79)	$237.21
MM-SCGHG	($271.68)	$17.57

Converting Jim Bridger Units 1 and 2 to operate on natural gas is expected to deliver $515.20 million in present-value net customer benefits in the MM scenario, $378.79 million in the HH scenario, and $271.68 million in the MM-SCGHG scenario. Under the MM, HH and MM-SCGHG scenarios, nominal levelized net benefits are $321.79/MWh, $237.21/MWh, and $17.57/MWh, respectively. Company forecasting and the relative magnitude of benefits over costs across these scenarios, as well as near-term resource need and the ability of the project to reduce the Company's reliance, strongly support the conversion of Jim Bridger Units 1 and 2.

IV. ROCK CREEK I

Q. Please describe the acquisition of Rock Creek I.

A. As described in the testimony of Company witness Jeffrey M. Wagner, Confidential Exhibit PAC/1200, PacifiCorp is acquiring 190 MW Rock Creek I facility. This project will be built by Invenergy under a build-transfer agreement (BTA) and will be transferred to the Company on completion of the project. My testimony below provides the economic justification for the Company's decision to acquire the project.

[7] Exhibit PAC/901 Jim Bridger Analysis.

A. <u>Need</u>

Q. Does PacifiCorp have a need for Rock Creek I?

A. Yes. As discussed above, PacifiCorp's 2021 IRP identifies a significant need for new resources over the near term. This need grew when the Company prepared its 2021 IRP Update. And this need has grown further due to an updated load forecast, and due to an under procurement of new solar and battery resources from the 2020AS RFP.

Q. Is Rock Creek I part of the 2021 preferred portfolio?

A. Yes. As discussed above, the 2021 IRP preferred portfolio includes 1,792 MW of new wind generation resulting from the 2020AS RFP, which includes 190 MW from Rock Creek I.[8]

Q. Please describe key factors that support including Rock Creek I in PacifiCorp's 2021 IRP preferred portfolio.

A. Rock Creek I is expected to meet the Company's near-term resource need and provide significant customer benefits by providing zero-fuel cost generation and substantial production tax credit (PTC) benefits, while mitigating risks associated with future regulation of carbon-emitting resources.

Q. Please describe the reliability benefits of projects like Rock Creek I.

A. Acquiring Rock Creek I reduces the Company's exposure to price and volume volatility by reducing the need for market purchases. Increased reliance on the market exposes customers to price volatility and price spikes that occur when the region experiences severe weather events or system disruptions. Such events increase net

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[8] *Id.* at Vol. I, Ch. 9.

power costs, and the magnitude of increase is directly proportional to the volume of purchases needed. In short, there is no guarantee that there will be a seller when PacifiCorp needs to make a short-term purchase to serve its load. This risk also exists for firm forward market purchases, where the seller could cut scheduled deliveries and accept liquidated damages if they do not have sufficient supply to meet their contractual obligations of the sale. As discussed in Company witness Link's testimony, Western Electricity Coordinating Counsel and North American Electric Reliability Corporation (NERC) reliability studies highlight the risks of resource shortfalls across the region in the coming years.

Q. How do these studies relate to Rock Creek I?

A. Each of these studies confirm the generally accepted understanding that the west is facing increasing resource adequacy risks in the near term. More recently, NERC further confirmed these findings and warned in its 2022 Summer Reliability Assessment that several regions in North America were at high or elevated risk of power outages this past summer due to above-normal temperatures and drought conditions, particularly in the western half of Canada and the United States.[9]

Rock Creek I will help mitigate the risk that there may be inadequate supply to support market purchases and reduce exposure to price spikes in periods where demand threatens to exceed supply for market purchases.

Q. Was Rock Creek I selected in the 2020AS RFP?

A. Yes. As discussed in Company witness Link's testimony, the 2020AS RFP final shortlist included six final shortlist bids representing over 1,600 MW of wind

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[9] 2022 Summer Reliability Assessment, North American Electric Reliability Corporation (May 2022) (https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2022.pdf).

generation that seek to interconnect to PacifiCorp's transmission system. These bids include Rock Creek I, which together with Rock Creek II, were the only two bids that were not power purchase agreements.

Q. Following their selection to the 2020AS RFP final shortlist, did the Company begin negotiating BTAs for the Rock Creek Projects?

A. Yes. Both Rock Creek I and Rock Creek II were proposed by the same developer (Invenergy) and, as discussed by Company witness Wagner, the Company engaged in BTA negotiations with Invenergy for Rock Creek I. Because Rock Creek I and II have the same counterparty and are being developed simultaneously subject to materially identical BTAs, the Company's economic analysis has largely analyzed the projects together.

Q. Were negotiations impacted by current economic conditions?

A. Yes. Bidder development efforts were challenged by importation restrictions related to China, COVID-19 international impacts, and hostilities in Ukraine that created significant logistics and supply chain challenges associated with solar panels, wind turbines, lithium batteries, transformers, and many balance-of-plant materials. As a result, many developers have been forced to abandon established supply chains and revert to new suppliers (if available), which has materially impacted overall renewable power plant pricing and commitments toward project in-service dates.

Given PacifiCorp's need for generation resources, PacifiCorp allowed pricing adjustments from all final shortlist projects from the 2020AS RFP, as well as limited extensions to commercial operations dates. Despite this additional flexibility, some of the bids from the final shortlist were unable to provide firm prices and were not available for selection. As noted earlier, this contributed to an under procurement of 902 MW of solar capacity and 497 MW of battery capacity.

Q. Have current economic conditions impacted costs for Rock Creek I relative to the costs offered in the initial bid that was used to establish the final shortlist?

A. Yes. Given the market dynamics discussed above, the overall costs for Rock Creek I has increased from the bid in the 2020AS RFP. The economic analysis below is based on updated project costs.

Q. Were there any additional benefits associated with Rock Creek I that offset the increased costs?

A. Yes. PacifiCorp's original economic analysis in the 2020AS RFP assumed that Rock Creek I qualified for a 60 percent PTC through the first 10 years of operation. As a result of the IRA, the economic analysis in this case reflects the value of the 110 percent PTC, in addition to the updated project costs. These updates cause a significant and positive change in the economic benefits of Rock Creek I.

Q. Have current economic drivers also impacted the Company's resource needs?

A. Yes. While the costs of 2020AS RFP bids have increased, the Company's resource needs have also increased. It is also important to consider the broader regional capacity need that aligns with the Company's need, and expected in-service date for Rock Creek I. The 2020AS RFP included virtually every potential non-market resource in the region capable of achieving commercial operation by 2025. Meeting this near-term need with physical assets that will provide incremental generation capacity effectively limits the Company's options to bidders in the 2020AS RFP.

Therefore, the 2020AS RFP bids and Rock Creek I remain necessary to reliably serve customers, including customers in Wyoming, and Rock Creek I's selection in the RFP confirms it is part of the least-cost, least-risk resources available to meet the Company's need.

Q. Was Rock Creek I included in the Company's 2021 IRP Update preferred portfolio?

A. Yes.[10]

Q. Where there any important modeling updates in the 2021 IRP Update?

A. As discussed in Chapter 5 of the 2021 IRP Update, key updates in addition to the load-and-resource balance include the resource changes due to 2020AS RFP activity, which is discussed further below. Importantly, the EPA's pre-publication version of the OTR, released on March 11, 2022, was not modeled in the 2021 IRP Update.

Q. Does the 2021 IRP Update consider the reliability issues related to reliance on market purchases?

A. Yes. Given near-term concerns over resource adequacy, and because of the acquisition of additional resources including Rock Creek I, the 2021 IRP Update's preferred portfolio shows generally lower market purchases in the first five years relative to the 2021 IRP preferred portfolio.[11]

B. <u>Modeling Assumptions and Methods</u>

Q. Did the Company analyze Rock Creek I and Rock Creek II together?

A. Yes, for the most part. As stated above, there were two BTA wind facilities in the Company's final shortlist of projects: Rock Creek I and Rock Creek II. The second

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[10] PacifiCorp 2021 IRP Update, Ch. 7, Action Item 2e, at 103 (Mar. 31, 2022).
[11] *Id.* at Figure 1.11.

facility is a much larger wind facility, at 400 MW compared to Rock Creek I at 190 MW. In previous regulatory proceedings, the Company analyzed the wind projects together to determine whether acquiring the projects would provide net benefits to customers. This was reasonable, because the projects are co-located with each other and share the same modeling assumptions.

That is contrasted with this proceeding, where the Company is only requesting rate recovery of Rock Creek I, because Rock Creek II has an in-service date that falls outside the test period of this rate case. Nonetheless, several of the analyses below include combined results from both wind projects, as well as Rock Creek I specific analyses. This allows the Commission to examine both the additive benefits that will occur when wind projects are interconnected to PacifiCorp's system, but also the Rock Creek I specific customer benefits that inform the Company's revenue requirement in this proceeding.

Q. Please summarize the natural gas and CO_2 price assumptions used in the economic analysis of Rock Creek I.

A. The economic analysis of Rock Creek I included three price-policy scenarios—the MM, MN, and LN price-policy scenarios.[12] These assumptions can influence the value of system energy, the dispatch of system resources, and PacifiCorp's resource mix. Consequently, wholesale-power prices and CO_2 policy assumptions affect NPC benefits, non-NPC variable-cost benefits, and system fixed-cost benefits associated

[12] The Company did not include a high gas price/no CO_2, high gas/medium CO_2, or medium gas/SCGHG price policy as these analyses would be less insightful. All scenarios have either higher avoided natural gas fuel costs or carbon prices, that each result in procuring more alternative resources, and greater savings and customer benefits from Rock Creek. This is intuitive, because higher natural gas costs or carbon prices decrease the demand for natural gas, but alternative emitting resources would still have a higher cost than Rock Creek, resulting in more incremental savings from resources like Rock Creek that have no variable fuel costs.

with Rock Creek I. Because wholesale power prices and CO_2 policy outcomes are both uncertain and important drivers to the economic analysis, it is important to evaluate a range of assumptions for these variables. Table 3 summarizes the price-policy scenarios used to analyze Rock Creek I.

Table 3. Price-Policy Scenario Assumption Overview

Price-Policy Scenario	Henry Hub Natural Gas Price (Levelized $/MMBtu)*	CO_2 Price Description
MM	$4.52	$12.10/ton starting 2025 rising to $51.40/ton in 2040
MN	$4.52	None
LN	$2.92	None
*Nominal levelized Henry Hub natural gas price from 2025 through 2040.		

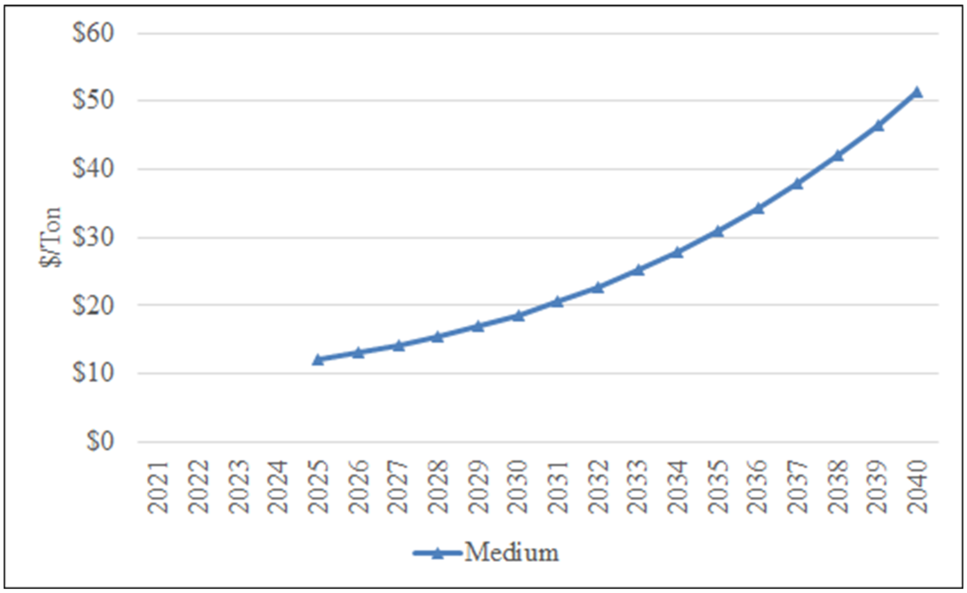
Q. Please describe the natural-gas price assumptions used in the price-policy scenarios.

A. The medium natural gas price assumptions are from PacifiCorp's OFPC dated June 30, 2022, which was the most current OFPC available when PacifiCorp prepared its modeling inputs for the 2020AS RFP. The first 36 months of the OFPC reflect market forwards at the close of a given trading day (June 30, 2022, in this case). As such, these 36 months are market forwards as of June 2022. The blending period (months 37 through 48) is calculated by averaging the month-on-month market forwards from the prior year with the month-on-month fundamentals-based price from the subsequent year. The fundamentals portion of the natural gas OFPC reflects Aurora-forecast prices.

Q. Please describe the CO_2 price assumptions used in the price-policy scenarios.

A. PacifiCorp used two different CO_2 price scenarios—zero and medium. The medium scenario is derived from a survey of third-party industry experts, including IHS CERA, and Wood Mackenzie and the Energy Information Administration as well as CO_2 price assumptions used by peer utilities. The resulting CO_2 price is applied as a tax beginning in 2025, as shown in Figure 1.

Figure 1. CO2 Price Assumptions



Q. Did PacifiCorp update its load forecast in its analysis of Rock Creek I?

A. Yes. The Company used a sales and load forecast that was completed in May 2022.

Q. How does the May 2022 forecast compare to the load forecast used in the 2021 IRP?

A. Figures 2 and 3 show PacifiCorp's May 2022 load and peak forecast relative to the 2021 IRP before incremental energy efficiency savings. A higher load forecast is being driven by new industrial and commercial customer growth, increased air conditioning saturations and miscellaneous devices and electric vehicle adoption expectations. The updated load forecast also accounts for updates to weather, temperature, and line losses to account for the progression of historical data since the load forecast that informed the 2021 IRP.

On average, over the 2023 through 2040 timeframe, forecast system load is up 13.6 percent per year and forecast coincident system peak is up 14.1 percent per year when compared to the 2021 IRP. Over that same timeframe, the average annual growth rate for the May 2022 forecast, before accounting for incremental energy efficiency improvements, is 2.04 percent for load and 1.66 percent for peak.

Figure 2. Forecast Annual System Load

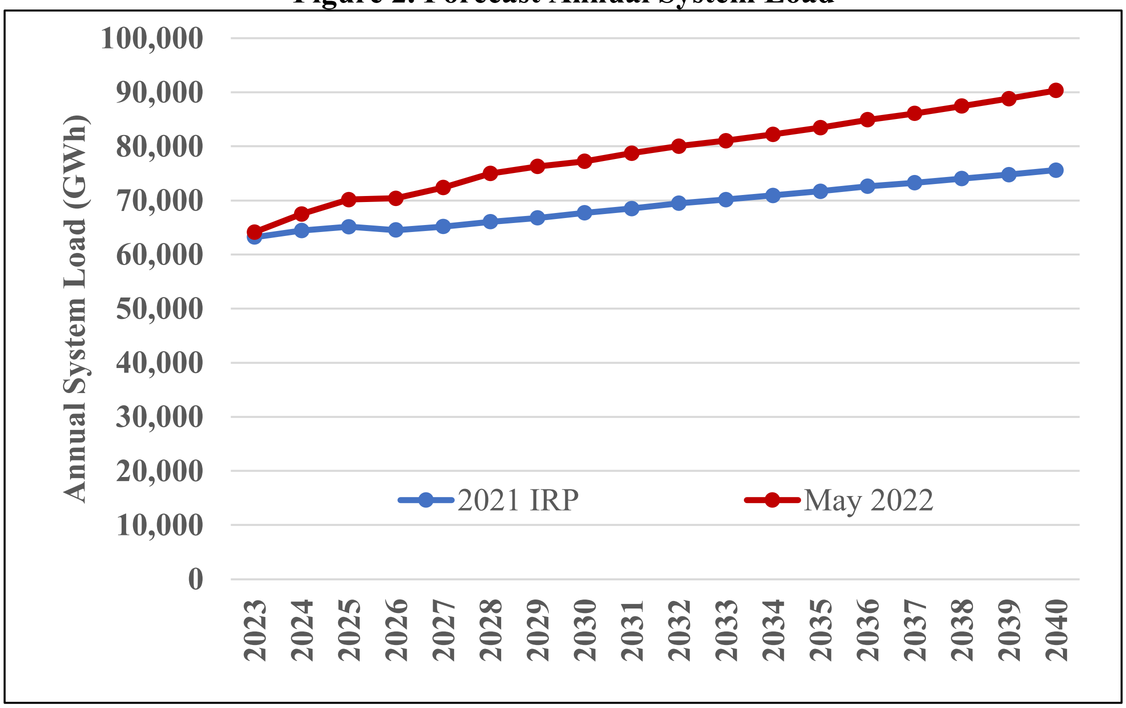
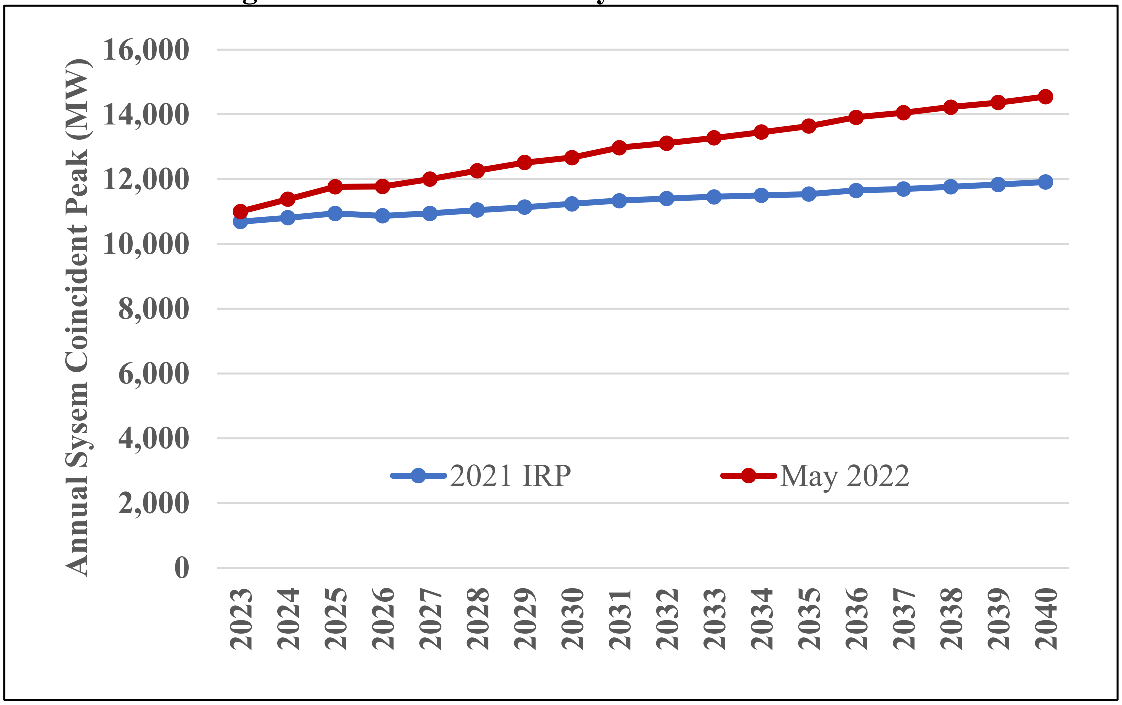


Figure 3. Forecast Annual System Coincident Peak



Q. Has PacifiCorp incorporated the EPA's proposed OTR in its analysis of Rock Creek I?

A. Yes. PacifiCorp modeled two primary components to reflect the OTR: NO_X allowance requirements for each of its units including penalties for units with high emissions rates, and a dispatch target or shadow price for NO_X allowances, which is used to avoid producing NO_X emissions during periods when the economic benefits are relatively low. After running the model, PacifiCorp compared the results to forecasts of its annual allocation of NO_X allowances for Utah and Wyoming.

Q. Please describe how the annual allocation of NO_X allowances would work under the proposed rule.

A. The proposed rule calls for dynamic budgeting of NO_X allowances in 2025 and beyond, with available allowances allocated among resources within a state based on the recent historical heat input and emissions rates of each resource. Under the EPA's proposed rule, the forecast allocation of NO_X allowances drops significantly in 2026, as the EPA assumed that selective catalytic reduction (SCR) installations at eligible facilities would significantly reduce emissions by that year. PacifiCorp's thermal facilities in Utah would be covered by the rule beginning 2023 and thermal facilities in Wyoming could be covered by the rule beginning 2024.

While trading of NO_X allowances among participating states is allowed, the proposed OTR includes significant penalties if a state's emissions exceed 121 percent of its annual allocation. Limited banking of NO_X allowances is also allowed, but emissions met via banked allowances may also be subject to penalties if a state's emissions exceed 121 percent of its annual allocation. To avoid such penalties, PacifiCorp's NO_X emissions during the ozone season (May-September) in each state cannot exceed 121 percent of PacifiCorp's forecast allocation of NO_X allowances for that state.

Q. Please describe how PacifiCorp developed NO_X allowance requirements for each of its units.

A. In general, an allowance for one ton of NO_X emissions would allow the holder of the allowance to emit one ton of NO_X. However, starting in 2027,[13] the proposed OTR also imposes a daily NO_X emissions rate limit of 0.14 pounds-per-million British thermal units (lb/MMBtu) for each coal-fired facility, and requires emitters to provide an equivalent of triple allowances for any emissions that exceed that rate. For example, a resource with an emissions rate of 0.20 lb/MMBtu would have an

[13] Coal units that currently have SCR installed must meet the daily backstop limit in 2024. Coal units that do not currently have SCR installed must meet the daily backstop limit in 2027.

effective allowance requirement of 0.32 lb/MMBtu.[14] To calculate PacifiCorp's NO_X allowance requirements under the OTR, starting in 2027 the modeled emission rates for coal resources whose emissions exceed 0.14 lb/MMBTU were grossed up to account for the additional surrender of allowances.

Q. Please describe how PacifiCorp developed a dispatch target to manage its NO_X allowance requirements.

A. While trading is allowed under the EPA's proposed OTR, the restrictions on inter-state transfers limit the number of potential counterparties. PacifiCorp's generation fleet is an appreciable portion of the electric generating units in both Utah and Wyoming, so the potential counterparties that could have allowances available for sale within those states is quite limited. With that in mind, PacifiCorp's current planning assumes that it will comply with the OTR using only its own combined allocation of NO_X allowances, and is meant to ensure that its annual allowance requirements do not exceed 100 percent of the sum of its Utah and Wyoming allowance allocations. When combined with state-specific limits previously described, while either PacifiCorp's Utah or Wyoming NO_X allowance requirements could be up to 121 percent of that state's allocation, any increase in one state would have to be accompanied by a reduction in emissions allowance requirements from PacifiCorp resources in the other state.

PacifiCorp's primary production cost analysis relies upon PLEXOS ST modeling that identifies system costs for a single deterministic set of expected or normal input conditions. In reality, and in stochastic modeling the Company performs

[14] Effective allowance requirement for resource with emissions rate of 0.20 lb/MMBTU: 100% * 0.20 lb/MMBtu + 200% * (0.20 – 0.14) lb/MMBtu = 100% *0.20 + 200% * 0.06 = 0.32 lb/MMBtu.

using the PLEXOS MT model, significant variations in inputs such as load, hydro generation, and thermal availability are a normal course of operations. Each of these inputs can unexpectedly increase PacifiCorp's need for NO_X emission allowances. Because banking and trading are limited under the OTR, variations in NO_X emissions that might otherwise average out over time must comply in every year and under every set of conditions. As a result, the NO_X allowances used under "normal" input conditions will likely need to be somewhat below the forecast limit to ensure sufficient allowances are available to meet unexpected input conditions.

PacifiCorp's analysis indicated that using a NO_X allowance dispatch target of [redacted] in the ST model would result in NO_X allowance requirements that were under PacifiCorp's forecast allocation and would leave sufficient allowances to meet a range of potential "above-normal" conditions. Whenever the incremental value of using a high NO_X emitting resources exceeds the dispatch target price, the model will deploy the high NO_X resource, rather than lower NO_X alternatives, which are typically gas-fired resources or market transactions. For a coal-fired resource with a NO_X emissions rate of 0.20 lb/MMBtu, the NO_X dispatch target price means that the resource would not be dispatched unless it provides at least [redacted] in incremental value relative to no NO_X alternatives, or a proportional amount of incremental value relative to lower NO_X alternatives.[15]

The dispatch target price is used to direct the model to avoid emissions, and is not a direct cost, as the Company would receive its allowance allocation free of

[15] A 0.20 lb/MMBTU coal-fired resource would have a NO_X credit requirement of 0.32 lb/MMBTU in 2027 and beyond, as detailed in footnote 22. A typical average heat rate for a coal-fired resource is 11 MMBtu/MWh. [redacted] ÷ 2,000 lb/ton * 0.32 lb/MMBtu * 11 MMBtu/MWh = [redacted].

charge under the proposed rule. While the Company could potentially sell allowances, there is little indication what market prices may prevail, and market prices may be below this target. As a result, no direct costs or revenues for allowances are included in the analysis. The allowance requirements resulting from this dispatch target price vary over time as the OTR requirements take full effect and as the Company's portfolio evolves. The Company's load forecast and other modeling inputs also play a role in the resulting volumes. A comparison of the allowance requirements for the scenarios relative and forecast allowance allocations is discussed in the Price-Policy Scenario Results section later in my testimony.

Q. Please describe the modeling methodology PacifiCorp used in its analysis of Rock Creek I.

A. Consistent with IRP modeling practices, the Company calculated a system PVRR by identifying least-cost resource portfolios and dispatching system resources through 2040, which aligns with the 20-year forecast period used in the 2021 IRP and 2021 IRP Update. Net customer benefits are calculated as the PVRR(d) between different simulations of PacifiCorp's system. One simulation includes both Rock Creek I and Rock Creek II, and the other simulation excludes them. The simulation that includes both projects includes transmission interconnection costs. When the two simulations are compared, changes to system costs are attributable to both projects. These also include simulations before passage of the IRA, and after to reflect the value of increased PTCs.

PacifiCorp also calculated a PVRR(d) based on one simulation that includes only Rock Creek I and compares it to a simulation that excludes both Rock Creek projects and one simulation that includes only Rock Creek II and compares it to a simulation that excludes both Rock Creek projects. In all studies, the Gateway West and Gateway South transmission projects discussed in Company witness Link's testimony were assumed to be in-service, and beyond 2025 proxy resource options from the 2021 IRP are available to meet system needs.

Customers are expected to realize benefits when the system present-value revenue requirement (PVRR) from the simulation with the projects is lower than the system PVRR without. Conversely, customers would experience increased costs if the system PVRR with the projects is higher than the system PVRR without.

Q. What portfolios did you analyze using the PLEXOS model in this case?

A. Portfolios were analyzed with and without both projects, with and without Rock Creek I, and with and without Rock Creek II, including certain results pre-IRA and post-IRA.

Q. Did PacifiCorp analyze how other assumptions affect its economic analysis of the wind projects?

A. Yes. PacifiCorp analyzed sensitivities that quantify how changes in capital costs and PTC values influence projected customer benefits.

C. <u>Price-Policy Scenario Results</u>

Q. Please summarize the pre-IRA results for the simulations that focused on each Rock Creek project individually.

A. Tables 4 and 5 summarize the PVRR(d) results for each price-policy scenario for the scenarios that examined each of the Rock Creek projects prior to passage of the IRA.

Table 4. Pre-IRA (Benefit)/Cost of Rock Creek I ($ million)

Price-Policy Scenario	PVRR(d)	Risk-Adjusted PVRR(d)
MM	(15)	(20)
MN	(9)	(15)
LN	3	(2)

Table 5. Pre-IRA (Benefit)/Cost of Rock Creek II ($ million)

Price-Policy Scenario	PVRR(d)	Risk-Adjusted PVRR(d)
MM	(24)	(33)
MN	(14)	(24)
LN	8	(3)

Rock Creek II generally provides a larger benefit, because it is approximately twice the size of Rock Creek I. All the same, under the MM price-policy scenario, Rock Creek I lowers total-system costs by $15 million, and adjusted for risk these benefits increase to a $20 million reduction in system costs. System benefits generally mirror the results seen in Table 5 when both projects were considered together, with a slight cost for Rock Creek I and Rock Creek II in the LN scenario prior to adjusting for risk and benefits in each of the other scenarios. Both projects, when evaluated individually, yield benefits on a risk-adjusted basis among all three price-policy scenarios.

Q. Why did PacifiCorp decide to update its economic analysis after passage of the IRA?

A. Based on existing law, PacifiCorp's economic analysis assumed that Rock Creek I qualified for 60 percent of available PTCs through the first 10 years of operation. After passage of the IRA, the Company understands that both Rock Creek projects qualify for 110 percent of available PTCs. This provides a significant increase to the economic benefits from the projects, and the Company's updated analysis reflects those benefits. The Company also updated its analysis to reflect current project costs.

Q. Please summarize the PVRR(d) results post-IRA.

A. Table 6 summarizes the PVRR(d) results for each price-policy scenario from the combined projects after passage of the IRA.[16]

Table 6. Post-IRA (Benefit)/Cost of Both Wind Projects ($ million)

	(a)	(b)	(c)	(d)	(e) = (c) + (d)	(f) = (a) + (e)	(g) = (b) + (e)
Price-Policy Scenario	**PVRR(d)**	**Risk-Adjusted PVRR(d)**	**110% PTC Update**	**Project Cost Update**	**Total Update**	**Updated PVRR(d)**	**Updated Risk-Adjusted PVRR(d)**
MM	(143)	(163)	(197)	42	(155)	(298)	(318)
MN	(33)	(51)	(194)	42	(151)	(185)	(202)
LN	16	2	(195)	42	(153)	(137)	(151)

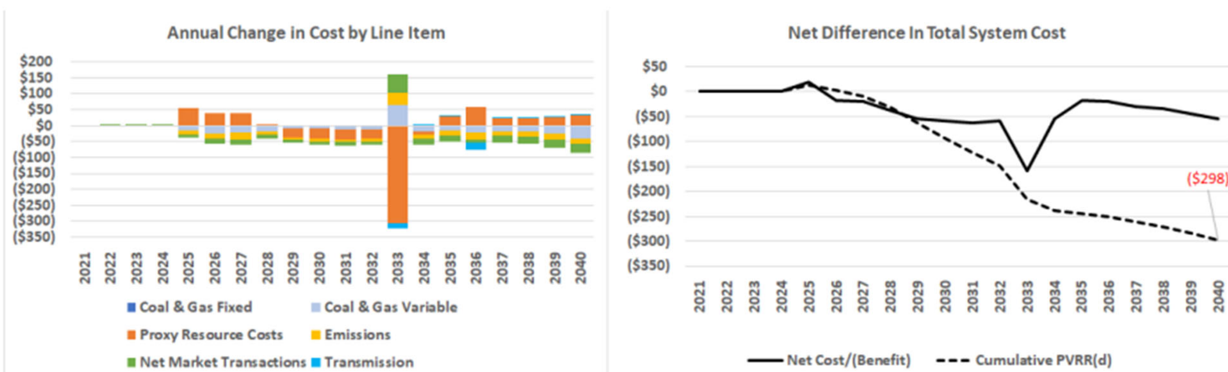
Before adjusting for risk (Column (g)), system costs are lower when the wind projects are included in the portfolio in all scenarios: ranging from a $137 million customer benefit under the LN scenario to $298 million in the MM scenario. When adjusting for risk (Column (g)), the benefits from the wind projects increase: ranging from $151 million in the LN scenario to $318 million in the MM scenario. The increase in customer benefits from the 110 percent PTC is substantial, even when accounting for the increase in project costs. This updated analysis supports the necessity of the wind projects, and indicates they will produce robust customer benefits. As discussed earlier, these benefits only increase under a high gas or a high CO_2 price-policy scenario.

[16] Confidential Exhibit PAC/902 Rock Creek Analysis.

Q. How do system costs change post-IRA with and without both projects?

A. Figure 6 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, when both projects are eliminated from the portfolio. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2040, the PVRR(d) shows that the portfolio that includes both projects is $298 million lower cost than the portfolio without both.

Figure 6. Increase/(Decrease) in System Costs when both Projects are Removed from the Portfolio ($ millions) Medium Gas/Medium CO2



Q. How do the risk-adjusted PVRR(d) results compare to the stochastic-mean PVRR(d) results?

A. For both projects, the risk-adjusted medium gas medium CO_2 PVRR(d) results show a benefit of $318 million, which is higher than the reported ST-model PVRR(d) results of $298 million prior to the risk adjustment. This indicates that the wind projects provide stochastic risk benefits by making the system less susceptible to low-probability combinations of load, market price, hydro generation, and thermal outage volatility that can increase system costs.

Q. How do the modeled OTR allowance requirements compare to PacifiCorp's forecast allowance allocation?

A. The annual allowance requirements in the ST-model results are generally slightly below a high estimate of PacifiCorp's allowance allocation. Based on the allocation methodology identified in the proposed rule, this high allowance allocation would likely require installation of SCR equipment at most of PacifiCorp's coal-fired generating units that are not equipped with that technology. In the absence of additional emission control equipment, PacifiCorp's allocation would be significantly lower, and well below the allowance requirements from the ST-model results. The high and low allocation forecasts and the ST-model results for the MM and MN price-policy scenarios are shown in Confidential Figure 7. As shown, allowance allocations could be significantly lower than what is assumed to be available in the current ST-model results, which would further increase the value of generation from resources without emissions, such as Rock Creek I.

[redacted]

[redacted]

Q. Would Rock Creek I provide customer benefits even if construction costs are higher than expected?

A. Yes. For both projects, a one percent increase in the initial capital costs would reduce PVRR benefits through 2040 by $9.1 million. To negate the $318 million in risk-adjusted, post-IRA benefits under the MM price-policy scenario, project costs would need to increase by 35 percent. To negate the $202 million in risk-adjusted, post-IRA benefits under the MN price-policy scenario, project costs would need to increase by 22 percent.

Q. Are the Company's economic analyses of the expected customer benefits from Rock Creek I conservative?

A. Yes. The PVRR(d) results for Rock Creek I do not reflect the potential value of RECs generated by the incremental energy output from the renewable project. Customer benefits for all price-policy scenarios would improve by approximately $14 million for every dollar assigned to the incremental RECs that will be generated through 2040.

Similarly, the Company's analyses understate forecast coal costs for certain system resources, including the Dave Johnston plant. If corrected to include the full costs of fuel supply for all plants, the Company's economic analysis would demonstrate even higher benefits for Rock Creek I. Additionally, the natural gas and electricity prices in the Company's September 2022 OFPC are higher than the values assumed in the June 2022 OFPC used in the Company's analysis, which would similarly result in higher benefits for Rock Creek I.

V. ROCK RIVER I

Q. Please describe the acquisition and repowering of the Rock River I wind facility.

A. As described in the testimony of Company witness Timothy J. Hemstreet, Confidential Exhibit PAC/1100, PacifiCorp is acquiring and repowering the 49 MW Rock River I wind facility. This involves installing approximately 19 wind turbine generators at the facility. These new turbines will increase the power generation from the previous capability, and extend the service life of the facility, and allow customers to benefit from this favorable wind site. My testimony below provides the economic justification for the Company's decision to acquire and repower Rock River I.

A. <u>Need</u>

Q. Did PacifiCorp's preferred portfolio of resources developed in the Company's 2021 IRP include Rock River I?

A. Yes.[17]

Q. Please describe the key factors for including Rock River I in the 2021 IRP preferred portfolio.

A. The project is anticipated to be fully online and serving customers by 2024. This timing enables the project to deliver needed energy and capacity for customers before the availability of either new proxy resources, or final shortlist project generation expected to be enabled by the Gateway South transmission line, as identified in the Company's 2020AS RFP. Without this project, the risk of shortfalls is increased as is the Company's reliance on energy markets. In its current state, the existing Rock River I facility is not operating as turbines have been removed pending the repowering of the sites. Repowering will allow the facility to once again provide energy and capacity to serve load and reduce market reliance, while allowing the newly installed turbines to qualify for substantial federal PTCs.

Q. Did the Commission acknowledge Rock River I as part of the 2021 IRP?

A. Yes.[18]

Q. Was Rock River I included in the Company's 2021 IRP Update?

A. Yes.[19]

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[17] *Id.* at Ch. 1 Action Plan, Action Item 2b, at 25.
[18] Order No. 22-178, at 6 (approving PacifiCorp's Action Plan generally).
[19] PacifiCorp 2021 IRP Update (Mar. 31, 2022).

B. Assumptions and Results

Q. Has the Company performed updated analyses of Rock River I after filing the 2021 IRP?

A. Yes. The Company performed a 30-year analysis of the project's economics through end-of-life using its PLEXOS modeling system, the same modeling system used for the 2021 IRP.

Q. Please summarize the natural gas and CO_2 price assumptions used in the economic analyses for Rock River I.

A. The economic analysis for each of the projects included four price-policy scenarios—representing low, medium, and high natural gas prices, and zero, medium, high, and the SCGHG CO_2 prices. The price-policy scenario that pairs medium natural gas prices with medium CO_2 prices is referred to as the "MM" scenario, the price-policy scenario that pairs low natural gas prices with a zero CO_2 price is referred to as the "LN" scenario, the price-policy scenario that pairs high natural gas prices with a high CO_2 price is referred to as the "HH" scenario, and the scenario that pairs medium natural gas prices with the SCGHG is referred to as the MM-SCGHG scenario. While the MM price-policy scenario represents the Company's "expected case" describing likely future conditions, the LN, HH, and MM-SCGHG scenarios provide informative analytical bookends scenarios.

Similar to the Company's Jim Bridger analyses, these assumptions can influence the value of system energy, the dispatch of system resources, and PacifiCorp's resource mix. Consequently, wholesale-power prices and CO_2 policy assumptions affect NPC, non-NPC variable-cost benefits, and system fixed-cost benefits associated with Rock River I. Because wholesale power prices and CO_2 policy outcomes are both uncertain and important drivers to the economic analysis, it is important to evaluate a range of assumptions for these variables. The natural gas and CO_2 price assumptions are summarized in Table 7.

Table 7. Price-Policy Assumptions

Price-Policy Scenario	Henry Hub Natural Gas Price (Levelized $/MMBtu)*	CO_2 Price Description
HH	$5.64	22.57/ton starting 2025 rising to 102.48/ton in 2040
MM	$4.44	$9.93/ton starting in 2025
LN	$2.94	None
MM-SCGHG	$4.44	$74.10/ton starting 2021 rising to $150.38/ton in 2040
*Nominal levelized Henry Hub natural gas price from 2025 through 2040.		

Q. Please describe the natural-gas price assumptions used in the price-policy scenarios.

A. The medium natural gas price assumptions are from PacifiCorp's OFPC dated March 31, 2021, which was the most recent OFPC available when the modeling inputs were developed. The first 36 months of the OFPC reflect market forwards at the close of a given trading day, May 2021 is the prompt month in this case. As such, these 36 months are market forwards as of May 2021. The blending period (months 37 through 48) is calculated by averaging the month-on-month market forwards from the prior year with the month-on-month fundamentals-based price from the subsequent year. The fundamentals portion of the natural gas OFPC reflects Aurora-forecast prices.

Q. Please describe the CO_2 price assumptions used in the price-policy scenarios.

A. PacifiCorp used four different CO_2 price scenarios—zero, medium, high, and the SCGHG. The medium scenario is derived from a survey of third-party industry experts, including IHS CERA, and Wood Mackenzie and the Energy Information Administration as well as CO_2 price assumptions used by peer utilities. Both the medium and high scenarios apply a CO_2 price as a tax beginning 2025. PacifiCorp also incorporated the SCGHG that is assumed to start in 2021 for Washington, and is applied such that the SCGHG is reflected in market prices and dispatch costs for the purposes of developing each portfolio (i.e., incorporated into capacity expansion optimization modeling).

Q. How did PacifiCorp pair the natural gas and CO_2 price assumptions for purposes of analyzing Rock River I?

A. Scenarios pairing medium gas prices with alternative CO_2 price assumptions reflect OFPC forwards through April 2024 before transitioning to a fundamentals forecast. Scenarios using high or low gas prices, regardless of CO_2 price assumptions, do not incorporate any market forwards because these scenarios are designed to reflect an alternative view to that of the market. As such, the low and high natural gas price scenarios are purely fundamental forecasts. Low and high natural gas price scenarios are also derived from expert third-party, multi-client, "off-the-shelf" subscription services.

Q. Please explain how you conducted your analyses.

A. The methodologies are consistent with the approach used to perform the economic analysis of portfolios in the 2021 IRP. The system value of incremental wind energy

Rock River I is calculated from two PLEXOS ST model simulations for a given price-policy scenario—one simulation with incremental wind energy and one simulation without incremental wind energy. The system value of incremental wind energy is then converted to a dollar-per-$/ MWh value by dividing the change in annual system cost by the change in incremental wind energy for both price-policy scenarios through 2040. The value of wind energy is extended out through 2050 by extrapolating the system values calculated from modeled data over the 2038-2040 timeframe. The assumed system value, expressed in dollars per$/ MWh, is applied to the incremental energy output associated with each of the wind repowering projects.

Q. Were your initial economic analyses of Rock River I conducted before passage of the IRA?

A. Yes.

Q. How does the IRA impact your analyses of Rock River I?

A. Based on existing law, PacifiCorp's initial economic analyses assumed that Rock River I qualified for 60 percent of available PTCs. After passage of the IRA, the Company understands that Rock River I now qualify for 110 percent of available PTCs.

Q. Has the Company updated its analysis of Rock River I after filing the 2021 IRP?

A. Yes. The Company updated its economic analysis in 2022 to support the Company's decision to acquire and repower Rock River I, and these results are reflected below. Table 8 summarizes the PVRR(d) between cases, with and without Rock River I acquisition and repowering, for customer benefits before and after passage of the IRA. This table also presents the same information on a levelized $/MWh basis.[20]

Table 8. Rock River I (Benefits)/Costs

Price-Policy Scenario	Pre-IRA PVRR(d) ($ million)	Pre-IRA Net Benefit ($/MWh)	Post-IRA PVRR(d) ($ million)	Post-IRA Net Benefit ($/MWh)
HH	($67.76)	($31/MWh)	($91.69)	($43/MWh)
MM	($30.15)	($14/MWh)	($54.09)	($25/MWh)
LN	$23.12	$11/MWh	($15.12)	($7/MWh)
MM-SCGHG	($143.42)	($67/MWh)	($167.35)	($78/MWh)

Before passage of the IRA, Rock River I was expected to deliver $30.15 million in present-value net customer benefits in the MM scenario, $67.76 million in the HH scenario, and $143.42 million in the MM-SCGHG scenario. This is contrasted with $23.12 million cost in the LN scenario. Under the MM-SCGHG, MM and HH scenarios, nominal levelized net benefits are $67/MWh, $14/MWh and $31/MWh, respectively. Under the LN scenario there is a nominal levelized net cost of $11/MWh. Company forecasting and the relative magnitude of benefits over costs across these scenarios, as well as near-term resource need and the ability of the project to reduce the Company's reliance on market purchases, all support acquiring and repowering Rock River I.

After passage of the IRA, customer benefits increased substantially: Rock River I will now deliver $54.09 million in present-value net customer benefits in the MM scenario and $91.69 million in the HH scenario. Importantly, the only scenario where Rock River I was expected to generate customer costs before passage of the

[20] Exhibit PAC/903 Rock River Analysis.

IRA—the LN scenario ($23.12 million)—has transformed to a $15.12 million customer benefit. These benefits only increase under a high gas or a high CO_2 price-policy scenario.

Q. Are the Company's economic analyses of the expected customer benefits from Rock River I conservative?

A. Yes. The PVRR(d) results for Rock River I do not reflect the potential value of RECs generated by the incremental energy output from the renewable project. Customer benefits for all price-policy scenarios would improve significantly for every dollar assigned to the incremental RECs that will be generated through 2040, and these RECs can also be sold to reduce the revenue requirement impact of this resource.

VI. CONCLUSION

Q. Please summarize the conclusions of your testimony.

A. PacifiCorp's analysis shows that the conversion of Jim Bridger Units 1 and 2 to natural gas, the acquisition of Rock Creek I, and the acquisition and repowering of Rock River I are necessary and will provide substantial customer benefits compared to anticipated project costs.

Q. What is your recommendation?

A. As supported by PacifiCorp's economic analysis, I recommend that the Commission determine that the Company's decisions to convert Jim Bridger 1 and 2, acquire Rock Creek I, and acquire and repower Rock River I are prudent.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 433
Exhibit PAC/901
Witness: Thomas R. Burns

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Thomas R. Burns

Jim Bridger Analysis

February 2024

Table 2 Jim Bridger 1&2 Gas Conversion

	PVRR(d) Net (Benefit)/Cost ($million)	Nom. Lev. Net Benefit ($/MWh of Incremental Energy)
Medium Natural Gas, Medium CO2	($515.20)	$321.79
Medium Natural Gas, No CO2	($595.67)	$609.59
Low Natural Gas, No CO2	($656.41)	$174.87
High Natural Gas, High CO2	($378.79)	$237.21
Medium Natural Gas, SCGHG	($271.68)	$17.57

Line No.	Nominal Discount Rate	6.88%																			
	Jim Bridger 1&2 Gas Conversion	**Formula**	**PVRR(d)**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
	Project Costs ($ millions)																				
	JB1 GC Capital Rev. Req.		$8.07	$0.00	$0.00	$0.00	$1.42	$1.36	$1.30	$1.25	$1.19	$1.14	$1.08	$1.03	$0.98	$0.93	$0.87	$0.82	$0.77	$0.71	$0.00
	JB1 GC Property Taxes		$0.40	$0.00	$0.00	$0.00	$0.00	$0.10	$0.09	$0.08	$0.08	$0.07	$0.06	$0.06	$0.05	$0.04	$0.04	$0.03	$0.02	$0.01	$0.00
	JB2 GC Capital Rev. Req.		$8.07	$0.00	$0.00	$0.00	$1.42	$1.36	$1.30	$1.25	$1.19	$1.14	$1.08	$1.03	$0.98	$0.93	$0.87	$0.82	$0.77	$0.71	$0.00
	JB2 GC Property Taxes		$0.40	$0.00	$0.00	$0.00	$0.00	$0.10	$0.09	$0.08	$0.08	$0.07	$0.06	$0.06	$0.05	$0.04	$0.04	$0.03	$0.02	$0.01	$0.00
(1)	**Project Costs ($ million)**		$16.94	$0.00	$0.00	$0.00	$2.83	$2.92	$2.79	$2.66	$2.54	$2.41	$2.29	$2.17	$2.05	$1.94	$1.82	$1.70	$1.58	$1.45	$0.00

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Line No.	**Medium Natural Gas, Medium CO_2**	**PVRR**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
	Total System Cost With JB 1&2 Gas Conversion ($ million)																			
(2)	TSC With JB 1&2 Gas Conversion	$21,723.3	$1,300.1	$1,342.1	$1,366.3	$1,413.9	$1,770.9	$2,001.6	$1,887.5	$2,092.5	$2,143.4	$2,360.3	$2,898.2	$3,084.6	$3,383.9	$3,563.2	$3,713.6	$3,917.3	$4,282.2	$0.0
(3)	Plus: Nominal Project Costs	$16.9	$0.0	$0.0	$0.0	$2.8	$2.9	$2.8	$2.7	$2.5	$2.4	$2.3	$2.2	$2.1	$1.9	$1.8	$1.7	$1.6	$1.5	$0.0
(4)	Less: Real Levelized Project Costs	($13.3)	$0.0	$0.0	$0.0	($1.6)	($1.7)	($1.7)	($1.7)	($1.8)	($1.8)	($1.9)	($1.9)	($1.9)	($2.0)	($2.0)	($2.1)	($2.1)	($2.2)	$0.0
(5)	TSC With JB 1&2 Gas Conversion	$21,727.0	$1,300.1	$1,342.1	$1,366.3	$1,415.1	$1,772.1	$2,002.7	$1,888.4	$2,093.2	$2,144.0	$2,360.8	$2,898.5	$3,084.7	$3,383.8	$3,563.0	$3,713.2	$3,916.8	$4,281.5	$0.0
(6)	**Total System Cost Without JB 1&2 Gas Conversion ($ million)**	$22,242.2	$1,296.9	$1,330.0	$1,357.9	$1,547.4	$1,844.6	$2,083.8	$1,966.6	$2,162.1	$2,212.3	$2,431.3	$2,939.5	$3,123.8	$3,455.9	$3,634.4	$3,784.0	$3,981.0	$4,345.9	$0.0
(7)	**Total System Cost / (Benefit) of JB 1&2 Gas Conversion ($ million)**	($515.2)	$3.2	$12.1	$8.5	($132.2)	($72.5)	($81.0)	($78.1)	($68.9)	($68.3)	($70.5)	($40.9)	($39.0)	($72.1)	($71.4)	($70.8)	($64.3)	($64.4)	$0.0

Line No.	**Medium Natural Gas, No CO_2**	**PVRR**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
	Total System Cost With JB 1&2 Gas Conversion ($ million)																			
(8)	TSC With JB 1&2 Gas Conversion	$18,754.5	$1,139.5	$1,206.4	$1,274.6	$1,335.8	$1,439.2	$1,677.8	$1,518.8	$1,760.8	$1,782.5	$1,983.4	$2,537.8	$2,688.7	$2,981.3	$3,110.0	$3,186.9	$3,295.9	$3,713.5	$0.0
(9)	Plus: Nominal Project Costs	$16.9	$0.0	$0.0	$0.0	$2.8	$2.9	$2.8	$2.7	$2.5	$2.4	$2.3	$2.2	$2.1	$1.9	$1.8	$1.7	$1.6	$1.5	$0.0
(10)	Less: Real Levelized Project Costs	($13.3)	$0.0	$0.0	$0.0	($1.6)	($1.7)	($1.7)	($1.7)	($1.8)	($1.8)	($1.9)	($1.9)	($1.9)	($2.0)	($2.0)	($2.1)	($2.1)	($2.2)	$0.0
(11)	TSC With JB 1&2 Gas Conversion	$18,758.1	$1,139.5	$1,206.4	$1,274.6	$1,337.0	$1,440.4	$1,678.9	$1,519.7	$1,761.5	$1,783.1	$1,983.9	$2,538.1	$2,688.8	$2,981.3	$3,109.8	$3,186.6	$3,295.4	$3,712.8	$0.0
(12)	**Total System Cost Without JB 1&2 Gas Conversion ($ million)**	$19,353.8	$1,135.3	$1,193.4	$1,266.0	$1,472.0	$1,527.9	$1,771.3	$1,612.6	$1,847.2	$1,874.1	$2,078.3	$2,587.6	$2,742.2	$3,055.3	$3,185.5	$3,262.8	$3,370.6	$3,774.5	$0.0
(13)	**Total System Cost / (Benefit) of JB 1&2 Gas Conversion ($ million)**	($595.7)	$4.2	$12.9	$8.6	($135.0)	($87.5)	($92.3)	($92.8)	($85.7)	($90.9)	($94.4)	($49.6)	($53.3)	($74.0)	($75.7)	($76.3)	($75.3)	($61.7)	$0.0

Line No.	**Low Natural Gas, No CO_2**	**PVRR**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
	Total System Cost With JB 1&2 Gas Conversion ($ million)																			
(14)	TSC With JB 1&2 Gas Conversion	$18,948.0	$1,239.8	$1,238.7	$1,284.2	$1,312.4	$1,412.6	$1,680.5	$1,532.7	$1,756.7	$1,783.3	$2,009.4	$2,571.7	$2,723.9	$3,012.1	$3,132.6	$3,225.6	$3,338.8	$3,699.6	$0.0
(15)	Plus: Nominal Project Costs	$16.9	$0.0	$0.0	$0.0	$2.8	$2.9	$2.8	$2.7	$2.5	$2.4	$2.3	$2.2	$2.1	$1.9	$1.8	$1.7	$1.6	$1.5	$0.0
(16)	Less: Real Levelized Project Costs	($13.3)	$0.0	$0.0	$0.0	($1.6)	($1.7)	($1.7)	($1.7)	($1.8)	($1.8)	($1.9)	($1.9)	($1.9)	($2.0)	($2.0)	($2.1)	($2.1)	($2.2)	$0.0
(17)	TSC With JB 1&2 Gas Conversion	$18,951.7	$1,239.8	$1,238.7	$1,284.2	$1,313.6	$1,413.9	$1,681.6	$1,533.6	$1,757.4	$1,783.9	$2,009.9	$2,571.9	$2,724.0	$3,012.1	$3,132.4	$3,225.2	$3,338.3	$3,698.9	$0.0
(18)	**Total System Cost Without JB 1&2 Gas Conversion ($ million)**	$19,608.1	$1,235.6	$1,225.6	$1,277.5	$1,452.9	$1,512.5	$1,788.3	$1,640.5	$1,860.0	$1,887.7	$2,112.5	$2,626.5	$2,778.6	$3,090.3	$3,212.0	$3,305.0	$3,415.6	$3,760.7	$0.0
(19)	**Total System Cost / (Benefit) of JB 1&2 Gas Conversion ($ million)**	($656.4)	$4.2	$13.2	$6.7	($139.3)	($98.7)	($106.7)	($106.9)	($102.6)	($103.7)	($102.6)	($54.6)	($54.6)	($78.3)	($79.7)	($79.8)	($77.3)	($61.8)	$0.0

Line No.	**High Natural Gas, High CO_2**	**PVRR**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
	Total System Cost With JB 1&2 Gas Conversion ($ million)																			
(20)	TSC With JB 1&2 Gas Conversion	$24,384.6	$1,324.1	$1,394.4	$1,445.8	$1,462.3	$2,163.8	$2,358.7	$2,266.5	$2,442.6	$2,501.9	$2,698.5	$3,248.7	$3,446.5	$3,750.2	$3,980.1	$4,167.9	$4,415.8	$4,796.6	$0.0
(21)	Plus: Nominal Project Costs	$16.9	$0.0	$0.0	$0.0	$2.8	$2.9	$2.8	$2.7	$2.5	$2.4	$2.3	$2.2	$2.1	$1.9	$1.8	$1.7	$1.6	$1.5	$0.0
(22)	Less: Real Levelized Project Costs	($13.3)	$0.0	$0.0	$0.0	($1.6)	($1.7)	($1.7)	($1.7)	($1.8)	($1.8)	($1.9)	($1.9)	($1.9)	($2.0)	($2.0)	($2.1)	($2.1)	($2.2)	$0.0
(23)	TSC With JB 1&2 Gas Conversion	$24,388.3	$1,324.1	$1,394.4	$1,445.8	$1,463.5	$2,165.0	$2,359.8	$2,267.4	$2,443.4	$2,502.5	$2,698.9	$3,248.9	$3,446.6	$3,750.1	$3,979.9	$4,167.5	$4,415.3	$4,795.9	$0.0
(24)	**Total System Cost Without JB 1&2 Gas Conversion ($ million)**	$24,767.1	$1,320.6	$1,380.8	$1,437.1	$1,585.8	$2,211.1	$2,411.3	$2,317.6	$2,487.5	$2,539.5	$2,737.7	$3,282.4	$3,476.0	$3,806.6	$4,041.1	$4,230.4	$4,468.9	$4,868.0	$0.0

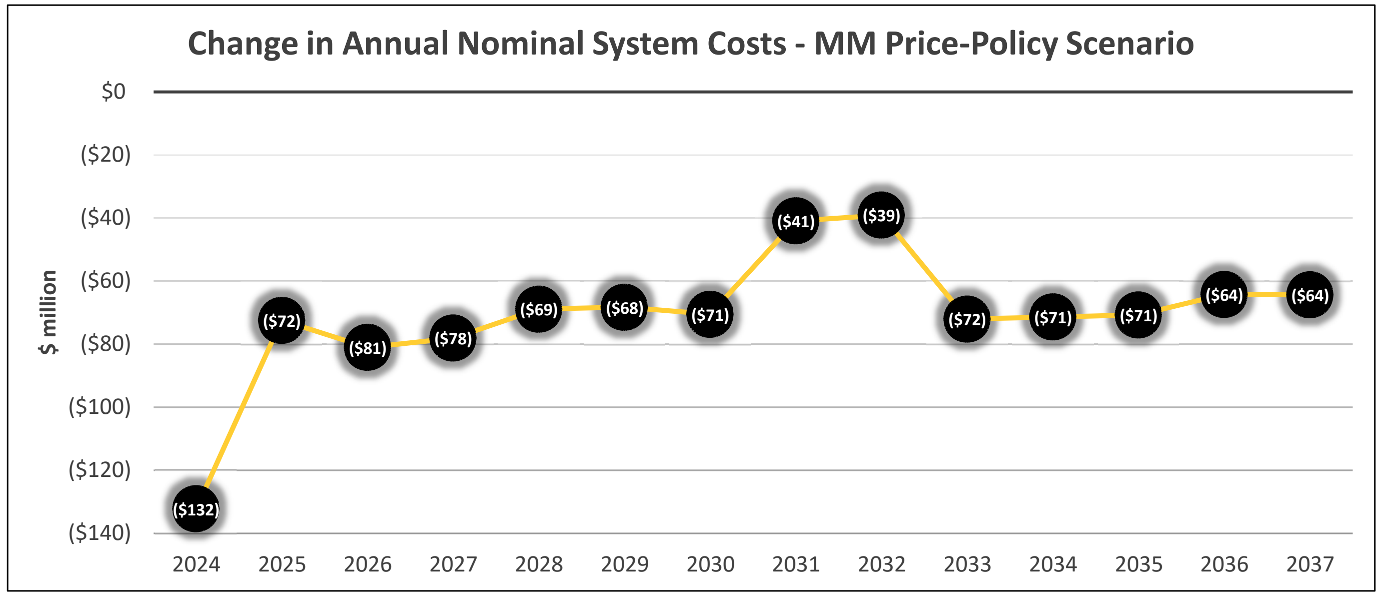
(25) **Total System Cost / (Benefit) of JB 1&2 Gas Conversion ($ million)**	($378.8)	$3.5	$13.6	$8.7	($122.3)	($46.0)	($51.5)	($50.2)	($44.1)	($37.1)	($38.8)	($33.5)	($29.4)	($56.5)	($61.2)	($62.9)	($53.5)	($72.0)	$0.0

Medium Natural Gas, SCGHG	**PVRR**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
Total System Cost With JB 1&2 Gas Conversion ($ million)																			
(26) TSC With JB 1&2 Gas Conversion	$35,083.0	$3,374.4	$3,528.6	$3,581.5	$3,413.6	$3,186.5	$3,134.4	$3,076.2	$3,121.7	$3,143.1	$3,267.4	$3,718.3	$3,853.9	$4,040.0	$4,231.8	$4,393.3	$4,661.3	$4,993.5	$0.0
(27) Plus: Nominal Project Costs	$16.9	$0.0	$0.0	$0.0	$2.8	$2.9	$2.8	$2.7	$2.5	$2.4	$2.3	$2.2	$2.1	$1.9	$1.8	$1.7	$1.6	$1.5	$0.0
(28) Less: Real Levelized Project Costs	($13.3)	$0.0	$0.0	$0.0	($1.6)	($1.7)	($1.7)	($1.7)	($1.8)	($1.8)	($1.9)	($1.9)	($1.9)	($2.0)	($2.0)	($2.1)	($2.1)	($2.2)	$0.0
(29) TSC With JB 1&2 Gas Conversion	$35,086.7	$3,374.4	$3,528.6	$3,581.5	$3,414.8	$3,187.8	$3,135.5	$3,077.1	$3,122.5	$3,143.7	$3,267.9	$3,718.6	$3,854.1	$4,039.9	$4,231.6	$4,392.9	$4,660.8	$4,992.8	$0.0
(30) **Total System Cost Without JB 1&2 Gas Conversion ($ million)**	$35,358.4	$3,370.9	$3,517.6	$3,588.0	$3,475.5	$3,204.1	$3,153.9	$3,091.7	$3,121.8	$3,145.4	$3,272.2	$3,760.4	$3,891.4	$4,096.5	$4,291.1	$4,454.4	$4,734.8	$5,192.8	$0.0
(31) **Total System Cost / (Benefit) of JB 1&2 Gas Conversion ($ million)**	($271.7)	$3.5	$11.0	($6.4)	($60.7)	($16.3)	($18.4)	($14.6)	$0.7	($1.7)	($4.3)	($41.8)	($37.4)	($56.6)	($59.4)	($61.5)	($74.0)	($200.0)	$0.0

Project Costs - Nominal 14 Yr																			
JB1 GC Capital Rev. Req.	$8,065,516	$0	$0	$0	$1,415,136	$1,360,683	$1,303,321	$1,246,994	$1,191,625	$1,137,143	$1,083,481	$1,030,578	$978,097	$925,678	$873,258	$820,838	$768,419	$711,565	$0
JB1 GC Property Taxes	$404,715	$0	$0	$0	$0	$99,500	$91,895	$84,431	$77,097	$69,885	$62,784	$55,787	$48,886	$42,000	$35,115	$28,229	$21,343	$14,458	$0
JB2 GC Capital Rev. Req.	$8,065,516	$0	$0	$0	$1,415,136	$1,360,683	$1,303,321	$1,246,994	$1,191,625	$1,137,143	$1,083,481	$1,030,578	$978,097	$925,678	$873,258	$820,838	$768,419	$711,565	$0
JB2 GC Property Taxes	$404,715	$0	$0	$0	$0	$99,500	$91,895	$84,431	$77,097	$69,885	$62,784	$55,787	$48,886	$42,000	$35,115	$28,229	$21,343	$14,458	$0
(32) **Project Costs ($ million)**	$16,940,461	$0	$0	$0	$2,830,272	$2,920,366	$2,790,430	$2,662,849	$2,537,445	$2,414,056	$2,292,531	$2,172,729	$2,053,966	$1,935,355	$1,816,745	$1,698,134	$1,579,524	$1,452,044	$0
Project Costs - Real Levelized 21 Yr																			
JB1 GC Capital Rev. Req.	$6,232,923	$0	$0	$0	$766,653	$783,174	$800,052	$817,293	$834,905	$852,898	$871,278	$890,054	$909,234	$928,828	$948,845	$969,292	$990,180	$1,011,519	$0
JB1 GC Property Taxes	$401,116	$0	$0	$0	$49,338	$50,401	$51,487	$52,596	$53,730	$54,888	$56,071	$57,279	$58,513	$59,774	$61,062	$62,378	$63,723	$65,096	$0
JB2 GC Capital Rev. Req.	$6,232,923	$0	$0	$0	$766,653	$783,174	$800,052	$817,293	$834,905	$852,898	$871,278	$890,054	$909,234	$928,828	$948,845	$969,292	$990,180	$1,011,519	$0
JB2 GC Property Taxes	$401,116	$0	$0	$0	$49,338	$50,401	$51,487	$52,596	$53,730	$54,888	$56,071	$57,279	$58,513	$59,774	$61,062	$62,378	$63,723	$65,096	$0
(33) **Project Costs ($ million)**	$13,268,079	$0	$0	$0	$1,631,981	$1,667,150	$1,703,077	$1,739,779	$1,777,271	$1,815,571	$1,854,697	$1,894,665	$1,935,495	$1,977,205	$2,019,814	$2,063,341	$2,107,806	$2,153,229	$0

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
MM				($132)	($72)	($81)	($78)	($69)	($68)	($71)	($41)	($39)	($72)	($71)	($71)	($64)	($64)

Figure 2 **Total-System Change in Annual Revenue Requirement Due to the Jim Bridger Unit 1&2 Gas Conversion ($ million)**



Discount Rate
6.88%

P02-MMGR ST Split Run Cost Data LT 5230 ST 19667

Total	Is FOM	Sample:	Mean

$ millions	NPV	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1 Coal VOM Costs																					
Retired Coal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EOL Coal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2 Coal Fixed Costs																					
Retired Coal FOM	426	77	94	79	67	63	30	30	32	13	13	13	13	14	13	13	14	17	0	0	0
Reclamation Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Retirement Costs	243	0	0	0	0	0	124	0	41	12	37	0	0	0	0	0	0	63	259	0	43
EOL Coal FOM	2,489	211	246	246	272	264	269	264	225	208	237	232	247	238	255	247	251	174	136	128	106
Total	3,158	289	339	325	339	327	423	294	299	234	287	245	260	252	268	260	265	254	395	128	149
3 Coal Fuel Costs																					
Retired Coal	404	174	95	104	23	12	5	7	12	6	5	7	6	9	9	9	15	14	0	0	0
Retired Coal Start Fuel	23	4	4	4	3	2	1	2	3	1	1	1	1	1	2	1	2	2	0	0	0
EOL Coal	3,345	401	433	427	528	419	360	354	315	316	265	238	208	194	179	168	180	172	43	39	52
EOL Coal Start Fuel	116	13	15	14	16	15	14	14	11	9	9	7	8	7	7	6	8	6	3	4	3
Total	3,887	592	546	549	569	448	380	376	341	333	280	254	224	210	196	184	205	194	47	43	56
4 Emission Cost (CO2)																					
Retired Coal	18	0	0	0	0	4	1	2	3	2	1	2	2	3	3	4	7	7	0	0	0
EOL Coal	1,510	0	0	0	0	242	231	249	218	227	215	204	191	196	193	198	238	244	88	90	125
Total	1,529	0	0	0	0	246	232	250	221	229	216	206	194	199	196	202	245	252	88	90	125
5 Proxy Generation Costs																					
Solar VOM	23	(4)	(2)	4	4	4	4	4	4	4	4	4	4	4	4	4	4	1	1	0	0
Wind VOM	(3,443)	(309)	(311)	(332)	(335)	(481)	(535)	(555)	(546)	(573)	(586)	(211)	(219)	(206)	(203)	(51)	14	14	15	15	15
Gas VOM	152	10	12	14	13	13	13	13	14	14	14	14	16	14	16	17	18	19	18	19	19
Battery VOM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LT Contract VOM	871	108	109	129	127	110	100	99	98	95	64	36	36	35	35	35	34	29	28	28	28
QFs VOM	2,054	275	266	252	233	231	228	210	208	194	190	189	174	148	145	143	112	31	23	9	6
Other VOM	(44)	1	1	1	1	1	1	1	(36)	(35)	(35)	(35)	(36)	(35)	15	15	15	15	43	43	44
Fuel	3,472	248	278	290	282	281	265	292	307	326	334	343	381	352	390	416	430	422	414	445	461
Start Fuel	77	9	6	5	9	9	8	9	10	8	7	6	7	6	7	7	7	5	4	5	5
Energy not Served	16	1	0	8	0	0	2	2	0	1	2	2	2	1	0	1	4	0	0	0	0
Dumped Energy	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Deficiency Cost	102	50	35	24	6	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0
Emissions Costs	843	0	0	0	0	52	54	65	71	78	86	97	119	117	143	169	191	203	209	241	263
Total	4,123	389	393	395	340	220	140	140	132	109	79	445	484	436	552	755	828	739	755	804	841
VOM Integration, Wind + Solar																					
6 Proxy Generation Resource Fixed Costs																					
Generator Fixed / Build Costs	5,089	8	8	8	15	15	218	218	352	352	537	704	765	1,035	1,035	1,035	1,035	1,237	1,601	1,601	1,849
Battery Fixed / Build Costs	453	0	0	0	0	0	0	0	0	74	74	74	74	74	74	74	74	162	162	162	162
Solar FOM	1,593	0	0	0	63	100	125	128	139	140	181	220	225	280	285	289	295	344	344	350	368
Wind FOM	4,893	160	163	191	198	467	523	539	559	572	604	620	678	679	613	603	616	623	638	646	656
Gas FOM	438	36	38	38	40	41	42	43	46	49	52	54	55	33	34	34	35	36	37	37	37
Battery FOM	62	0	0	0	1	(1)	(1)	(2)	(0)	12	10	10	9	9	9	9	9	23	18	30	31
Other FOM	667	12	5	5	6	5	7	7	85	86	80	81	83	85	86	88	90	92	280	286	336
Use of Service	(6)	0	0	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(2)	(2)	(2)	(2)
Total	13,189	215	213	241	322	628	915	933	1,181	1,284	1,538	1,763	1,889	2,193	2,135	2,132	2,153	2,515	3,078	3,110	3,436
Remove Portfolio Credits																					
7 DSM Costs																					
DR VOM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DR FOM	610	0	6	19	29	34	38	42	46	51	55	60	63	86	90	105	117	138	157	166	230
EE VOM	1,085	9	21	30	40	50	60	74	88	103	121	138	153	167	181	195	205	221	240	260	276
EE FOM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	1,695	9	27	49	70	84	98	115	134	154	176	198	216	253	271	300	322	359	397	427	506
8 Market Costs																					
System Market Sales	(4,142)	(273)	(247)	(267)	(302)	(336)	(376)	(417)	(426)	(426)	(449)	(478)	(476)	(470)	(458)	(476)	(479)	(484)	(477)	(457)	(597)
System Market Purchases	1,230	80	70	74	76	84	67	74	83	99	103	117	124	127	149	172	194	227	256	276	318
Total	(2,912)	(193)	(177)	(193)	(225)	(252)	(309)	(344)	(342)	(327)	(346)	(360)	(352)	(343)	(310)	(304)	(285)	(257)	(221)	(181)	(279)
9 Transmission Costs																					
Transmission Build / Reinforcement Costs	1,341	0	0	0	1	99	151	151	157	157	159	177	199	214	214	214	214	256	256	256	296
Total	1,341	0	0	0	1	99	151	151	157	157	159	177	199	214	214	214	214	256	256	256	296

11	Total System Cost	25,822	1,300	1,342	1,366	1,414	1,771	2,002	1,888	2,092	2,143	2,360	2,898	3,085	3,384	3,563	3,714	3,917	4,282	4,764	4,647	5,098
	Fixed	18,298	503	558	585	691	1,089	1,526	1,420	1,683	1,725	2,039	2,246	2,411	2,744	2,707	2,711	2,749	3,164	3,886	3,661	4,110
	Variable	7,711	797	784	781	723	711	504	496	439	447	351	682	703	670	815	1,033	1,198	1,148	908	1,016	1,018
	Adjustments	(187)	0	(0)	(0)	(0)	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(30)	(30)	41	(30)	(30)	(30)	(30)	(30)	(30)
12	Risk Adjusted PVRR	26,179		358																		
	Generation (GWH)																					
	Retired Coal	20,157	7,440	4,813	4,428	707	365	134	189	303	154	111	177	152	194	196	195	309	288	-	-	-
	EOL Coal	252,466	23,923	25,027	24,205	27,814	21,516	18,372	17,616	14,405	13,525	11,382	9,632	8,029	7,294	6,343	5,791	6,193	5,697	1,879	1,717	2,107
	DSM	147,142	2,431	2,919	3,424	3,991	4,488	4,947	5,516	6,127	6,731	7,359	7,909	8,411	8,828	9,290	9,733	9,986	10,423	11,033	11,570	12,027
	LT Contracts	32,363	1,441	1,685	2,597	3,063	2,434	2,264	2,229	2,213	2,149	1,656	1,204	1,185	1,172	1,160	1,145	1,132	925	914	904	891
	QFs	73,171	5,736	5,611	5,384	5,067	5,024	4,970	4,719	4,682	4,460	4,410	4,384	4,172	3,667	3,371	3,330	2,627	655	552	256	94
	Gas	225,862	10,129	11,701	13,173	11,326	11,369	10,702	11,328	11,178	11,119	11,034	11,088	11,976	10,567	11,480	12,000	12,129	11,574	10,582	10,869	10,536
	Solar	188,705	1,223	1,271	1,467	3,802	5,007	6,608	6,591	6,867	6,932	8,267	10,554	10,530	13,603	13,583	13,561	13,535	16,289	16,264	16,239	16,513
	Wind	362,823	9,172	9,225	9,695	10,006	15,849	18,275	18,282	18,392	18,345	20,175	20,181	21,718	21,616	21,637	21,646	21,752	21,662	21,660	21,661	21,874
	Other System	114,544	3,761	3,779	3,311	3,120	2,963	2,977	2,997	5,806	5,795	5,760	5,725	5,760	5,768	5,719	5,724	5,722	5,746	11,059	11,082	11,968
	Total	1,417,233	65,255	66,031	67,683	68,897	69,015	69,249	69,467	69,974	69,211	70,152	70,854	71,933	72,710	72,779	73,125	73,385	73,259	73,944	74,298	76,011
	Generation (GWH)																					
	JB12 GC	1,601	0	0	0	429	222	134	189	303	154	111	177	152	194	196	195	309	288	0	0	0

Discount Rate
6.88%

P02a-MMGR-BDG-GC ST Split Run Cost Data LT 9076 ST 19877

Total Is FOM Sample: Mean

$ millions	NPV	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1 Coal VOM Costs																					
Retired Coal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EOL Coal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2 Coal Fixed Costs																					
Retired Coal FOM	300	74	77	72	51	49	16	16	16	0	0	0	0	0	0	0	0	0	0	0	0
Reclamation Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Retirement Costs	243	0	0	0	52	0	124	0	41	12	37	0	0	0	0	0	0	63	128	0	43
EOL Coal FOM	2,489	211	246	246	272	264	269	264	225	208	237	232	247	238	255	247	251	174	136	128	106
Total	3,032	285	323	318	374	313	409	280	283	220	274	232	247	238	255	247	251	237	264	128	149
3 Coal Fuel Costs																					
Retired Coal	346	174	102	104	8	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Retired Coal Start Fuel	10	4	4	4	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EOL Coal	3,272	400	432	428	520	401	341	338	304	302	240	228	201	191	173	163	174	170	60	59	60
EOL Coal Start Fuel	115	13	15	14	16	14	13	14	11	8	8	7	7	7	7	6	8	7	4	5	4
Total	3,743	591	553	550	544	418	354	352	315	310	248	236	208	198	180	170	182	177	64	65	64
4 Emission Cost (CO2)																					
Retired Coal	1	0	0	0	0	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EOL Coal	1,472	0	0	0	0	231	218	235	209	216	194	197	185	191	186	192	230	242	122	132	146
Total	1,474	0	0	0	0	232	218	235	209	216	194	197	185	191	186	192	230	242	122	132	146
5 Proxy Generation Costs																					
Solar VOM	23	(4)	(2)	4	4	4	4	4	4	4	4	4	4	4	4	4	4	1	1	0	0
Wind VOM	(3,444)	(309)	(311)	(333)	(335)	(482)	(535)	(555)	(546)	(573)	(586)	(211)	(219)	(206)	(203)	(51)	14	14	15	15	15
Gas VOM	151	10	12	14	12	13	12	13	13	13	13	14	16	14	16	17	17	19	20	20	20
Battery VOM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LT Contract VOM	871	108	109	129	127	110	100	99	98	95	64	36	36	35	35	35	34	29	28	28	28
QFs VOM	2,054	275	266	252	233	231	228	210	208	194	190	189	174	148	145	143	112	31	23	9	6
Other VOM	(56)	1	1	1	1	1	1	1	(36)	(35)	(35)	(35)	(36)	(35)	15	15	15	15	29	28	32
Fuel	3,447	248	275	291	273	277	259	286	293	303	322	342	379	343	387	413	423	425	452	469	509
Start Fuel	72	9	6	5	7	7	7	8	9	6	6	6	8	6	7	7	6	5	4	5	5
Energy not Served	16	2	0	8	0	0	2	2	0	1	2	2	2	1	0	1	4	0	0	0	0
Dumped Energy	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Deficiency Cost	103	50	39	23	2	0	0	0	2	0	0	0	0	0	0	0	0	0	0	0	0
Emissions Costs	844	0	0	0	0	51	53	63	68	72	83	96	118	114	140	165	188	203	226	258	284
Total	4,083	390	395	395	325	214	131	129	113	79	63	443	481	424	547	749	818	742	799	834	900
VOM Integration, Wind + Solar																					
6 Proxy Generation Resource Fixed Costs																					
Generator Fixed / Build Costs	5,788	8	8	8	140	140	343	343	477	477	662	771	831	1,125	1,125	1,125	1,125	1,311	1,506	1,506	1,754
Battery Fixed / Build Costs	453	0	0	0	0	0	0	0	0	74	74	74	74	74	74	74	74	162	162	162	162
Solar FOM	1,762	0	0	0	92	129	154	157	168	169	211	234	239	293	299	303	310	349	350	355	374
Wind FOM	4,893	160	163	191	198	467	523	539	559	572	604	620	678	679	613	603	616	623	638	646	656
Gas FOM	438	36	38	38	40	41	42	43	46	49	52	54	55	33	34	34	35	36	37	37	37
Battery FOM	62	0	0	0	1	(1)	(1)	(2)	(0)	12	10	10	9	9	9	9	9	23	18	30	31
Other FOM	586	12	5	5	6	5	7	7	85	86	80	81	83	85	86	88	90	92	187	190	239
Use of Service	(6)	0	0	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(2)	(2)	(2)	(2)
Total	13,976	215	213	241	476	782	1,069	1,087	1,335	1,438	1,693	1,843	1,969	2,297	2,239	2,237	2,258	2,594	2,896	2,926	3,250
Remove Portfolio Credits																					
7 DSM Costs																					
DR VOM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DR FOM	610	0	6	19	29	34	38	42	46	51	55	60	63	86	90	105	117	138	157	166	230
EE VOM	1,085	9	21	30	40	50	60	74	88	103	121	138	153	167	181	195	205	221	240	260	276
EE FOM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	1,695	9	27	49	70	84	98	115	134	154	176	198	216	253	271	300	322	359	397	427	506
8 Market Costs																					
System Market Sales	(4,107)	(273)	(249)	(268)	(311)	(345)	(380)	(424)	(432)	(431)	(450)	(475)	(474)	(459)	(450)	(467)	(465)	(466)	(442)	(420)	(525)
System Market Purchases	1,250	80	68	74	68	77	64	69	77	97	103	118	122	130	151	173	200	235	291	316	368
Total	(2,857)	(193)	(181)	(194)	(243)	(268)	(316)	(355)	(354)	(333)	(348)	(357)	(352)	(329)	(299)	(294)	(265)	(231)	(151)	(104)	(157)
9 Transmission Costs																					
Transmission Build / Reinforcement Costs	1,341	0	0	0	1	99	151	151	157	157	159	177	199	214	214	214	214	256	256	256	296
Total	1,341	0	0	0	1	99	151	151	157	157	159	177	199	214	214	214	214	256	256	256	296

11	Total System Cost	26,299	1,297	1,330	1,358	1,547	1,845	2,084	1,967	2,162	2,212	2,431	2,939	3,124	3,456	3,634	3,784	3,981	4,346	4,618	4,633	5,123
	Fixed	19,202	500	542	578	932	1,228	1,790	1,561	1,863	1,879	2,218	2,312	2,478	2,834	2,798	2,802	2,841	3,288	3,701	3,477	3,967
	Variable	7,527	797	788	780	667	645	447	435	370	375	279	656	675	651	795	1,012	1,170	1,151	1,075	1,186	1,229
	Adjustments	(187)	0	(0)	(0)	(0)	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(30)	(30)	41	(30)	(30)	(30)	(30)	(30)	(30)
12	Risk Adjusted PVRR	26,648		349																		
	Generation (GWH)																					
	Retired Coal	17,392	7,447	5,204	4,374	277	89	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	EOL Coal	246,913	23,909	24,980	24,223	27,288	20,550	17,309	16,683	13,832	12,888	10,295	9,274	7,733	7,101	6,110	5,604	5,965	5,621	2,594	2,492	2,461
	DSM	147,019	2,430	2,918	3,429	3,976	4,465	4,918	5,483	6,103	6,731	7,359	7,908	8,410	8,829	9,289	9,733	9,986	10,423	11,033	11,570	12,027
	LT Contracts	32,363	1,441	1,685	2,597	3,063	2,434	2,264	2,229	2,213	2,149	1,656	1,204	1,185	1,172	1,160	1,145	1,132	925	914	904	891
	QFs	73,171	5,736	5,611	5,384	5,067	5,024	4,970	4,719	4,682	4,460	4,410	4,384	4,172	3,667	3,371	3,330	2,627	655	552	256	94
	Gas	224,627	10,112	11,549	13,232	11,011	11,263	10,448	11,086	10,708	10,393	10,655	11,009	11,866	10,301	11,249	11,754	11,921	11,589	11,444	11,669	11,368
	Solar	205,843	1,223	1,271	1,467	5,600	6,777	8,354	8,344	8,634	8,755	10,090	11,246	11,222	14,291	14,273	14,253	14,228	16,400	16,397	16,372	16,644
	Wind	362,823	9,171	9,224	9,704	10,016	15,855	18,280	18,289	18,387	18,345	20,171	20,179	21,711	21,609	21,630	21,641	21,751	21,662	21,661	21,660	21,875
	Other System	106,103	3,767	3,776	3,307	3,090	2,942	2,971	2,990	5,802	5,790	5,758	5,725	5,760	5,768	5,730	5,729	5,714	5,750	8,297	8,282	9,154
	Total	1,416,253	65,235	66,219	67,717	69,388	69,400	69,515	69,821	70,361	69,510	70,394	70,931	72,059	72,738	72,813	73,188	73,323	73,025	72,894	73,206	74,514

Discount Rate
6.88%

P02-MMGR-MN ST Split Run Cost Data LT 5230 ST 20612

Total Is FOM Sample: Mean

$ millions	NPV	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1 Coal VOM Costs																					
Retired Coal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EOL Coal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2 Coal Fixed Costs																					
Retired Coal FOM	426	77	94	79	67	63	30	30	32	13	13	13	13	14	13	13	14	17	0	0	0
Reclamation Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Retirement Costs	243	0	0	0	0	0	124	0	41	12	37	0	0	0	0	0	0	63	259	0	43
EOL Coal FOM	2,489	211	246	246	272	264	269	264	225	208	237	232	247	238	255	247	251	174	136	128	106
Total	3,158	289	339	325	339	327	423	294	299	234	287	245	260	252	268	260	265	254	395	128	149
3 Coal Fuel Costs																					
Retired Coal	374	173	96	101	24	18	4	5	10	2	1	0	0	0	0	0	0	5	0	0	0
Retired Coal Start Fuel	18	4	4	4	3	2	1	2	2	1	0	0	0	0	0	0	0	1	0	0	0
EOL Coal	4,570	403	420	421	514	510	475	484	439	458	426	433	437	424	438	443	463	371	208	213	184
EOL Coal Start Fuel	123	13	15	14	16	14	13	13	10	9	10	10	10	10	10	10	10	8	5	5	5
Total	5,085	593	534	540	557	544	494	504	461	470	436	443	447	434	448	453	474	385	213	218	188
4 Emission Cost (CO2)																					
Retired Coal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EOL Coal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5 Proxy Generation Costs																					
Solar VOM	23	(4)	(2)	4	4	4	4	4	4	4	4	4	4	4	4	4	4	1	1	0	0
Wind VOM	(3,441)	(309)	(311)	(332)	(335)	(480)	(534)	(553)	(545)	(573)	(586)	(211)	(219)	(206)	(203)	(52)	14	14	15	15	15
Gas VOM	111	11	14	16	15	10	8	8	9	8	8	7	6	5	6	6	7	13	14	14	16
Battery VOM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LT Contract VOM	871	108	109	129	127	110	100	99	98	95	64	36	36	35	35	35	34	29	28	28	28
QFs VOM	2,054	275	266	252	233	231	228	210	208	194	190	189	174	148	145	143	112	31	23	9	6
Other VOM	(45)	1	1	1	1	1	1	1	(36)	(35)	(35)	(35)	(36)	(35)	15	15	15	15	42	42	44
Fuel	2,498	271	305	309	301	221	175	187	215	210	191	167	159	134	150	157	176	283	301	324	385
Start Fuel	67	9	5	5	8	9	9	10	11	7	6	4	4	3	3	4	4	4	3	4	4
Energy not Served	15	1	0	8	0	0	2	2	0	1	2	2	2	1	0	1	3	0	0	0	0
Dumped Energy	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Deficiency Cost	103	50	35	26	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Emissions Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	2,255	413	421	416	360	106	(7)	(34)	(36)	(90)	(157)	162	130	88	155	313	368	390	427	436	498
VOM Integration, Wind + Solar																					
6 Proxy Generation Resource Fixed Costs																					
Generator Fixed / Build Costs	5,089	8	8	8	15	15	218	218	352	352	537	704	765	1,035	1,035	1,035	1,035	1,237	1,601	1,601	1,849
Battery Fixed / Build Costs	453	0	0	0	0	0	0	0	0	74	74	74	74	74	74	74	74	162	162	162	162
Solar FOM	1,593	0	0	0	63	100	125	128	139	140	181	220	225	280	285	289	295	344	344	350	368
Wind FOM	4,893	160	163	191	198	467	523	539	559	572	604	620	678	679	613	603	616	623	638	646	656
Gas FOM	438	36	38	38	40	41	42	43	46	49	52	54	55	33	34	34	35	36	37	37	37
Battery FOM	62	0	0	0	1	(1)	(1)	(2)	(0)	12	10	10	9	9	9	9	9	23	18	30	31
Other FOM	667	12	5	5	6	5	7	7	85	86	80	81	83	85	86	88	90	92	280	286	336
Use of Service	(6)	0	0	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(2)	(2)	(2)	(2)
Total	13,189	215	213	241	322	628	915	933	1,181	1,284	1,538	1,763	1,889	2,193	2,135	2,132	2,153	2,515	3,078	3,110	3,436
Remove Portfolio Credits																					
7 DSM Costs																					
DR VOM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DR FOM	610	0	6	19	29	34	38	42	46	51	55	60	63	86	90	105	117	138	157	166	230
EE VOM	1,085	9	21	30	40	50	60	74	88	103	121	138	153	167	181	195	205	221	240	260	276
EE FOM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	1,695	9	27	49	70	84	98	115	134	154	176	198	216	253	271	300	322	359	397	427	506
8 Market Costs																					
System Market Sales	(4,807)	(466)	(410)	(380)	(386)	(373)	(399)	(454)	(455)	(450)	(481)	(477)	(477)	(475)	(478)	(512)	(534)	(509)	(522)	(510)	(579)
System Market Purchases	720	88	82	83	74	52	33	38	49	54	55	56	53	53	57	57	64	93	105	107	157
Total	(4,087)	(378)	(328)	(297)	(312)	(320)	(366)	(416)	(405)	(396)	(426)	(421)	(424)	(422)	(421)	(454)	(471)	(416)	(417)	(404)	(422)
9 Transmission Costs																					
Transmission Build / Reinforcement Costs	1,341	0	0	0	1	99	151	151	157	157	159	177	199	214	214	214	214	256	256	256	296
Total	1,341	0	0	0	1	99	151	151	157	157	159	177	199	214	214	214	214	256	256	256	296

11 Total System Cost	22,449	1,140	1,206	1,275	1,336	1,439	1,678	1,519	1,761	1,783	1,983	2,538	2,689	2,981	3,110	3,187	3,296	3,714	4,319	4,142	4,620
Fixed	18,298	503	558	585	691	1,089	1,526	1,420	1,683	1,725	2,039	2,246	2,411	2,744	2,707	2,711	2,749	3,164	3,886	3,661	4,110
Variable	4,339	636	648	689	645	380	181	127	107	86	(26)	322	307	267	362	506	577	580	463	510	540
Adjustments	(187)	0	(0)	(0)	(0)	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(30)	(30)	41	(30)	(30)	(30)	(30)	(30)	(30)
12 Risk Adjusted PVRR	22,637		188																		
Generation (GWH)																					
Retired Coal	18,524	7,378	4,853	4,289	794	550	118	127	245	59	12	1	0	-	-	-	-	97	-	-	-
EOL Coal	383,064	24,043	24,239	23,774	27,179	26,640	24,844	24,749	20,624	20,396	19,070	18,728	18,505	17,514	17,567	17,886	18,385	14,065	8,786	8,848	7,219
DSM	147,207	2,446	2,942	3,447	3,994	4,479	4,955	5,524	6,127	6,731	7,358	7,907	8,411	8,827	9,289	9,733	9,986	10,423	11,033	11,570	12,026
LT Contracts	32,363	1,441	1,685	2,597	3,063	2,434	2,264	2,229	2,213	2,149	1,656	1,204	1,185	1,172	1,160	1,145	1,132	925	914	904	891
QFs	73,171	5,736	5,611	5,384	5,067	5,024	4,970	4,719	4,682	4,460	4,410	4,384	4,172	3,667	3,371	3,330	2,627	655	552	256	94
Gas	156,082	11,037	13,377	14,480	13,276	8,936	6,798	7,019	7,537	6,959	6,199	5,287	4,931	3,914	4,378	4,500	4,943	7,673	7,895	8,075	8,868
Solar	188,773	1,223	1,271	1,467	3,815	5,002	6,651	6,627	6,879	6,922	8,264	10,550	10,524	13,597	13,577	13,561	13,536	16,289	16,264	16,240	16,513
Wind	362,361	9,172	9,228	9,701	10,007	15,804	18,222	18,223	18,375	18,345	20,142	20,133	21,678	21,575	21,601	21,609	21,718	21,647	21,654	21,652	21,875
Other System	114,828	3,857	3,962	3,457	3,213	2,958	2,974	2,965	5,797	5,791	5,760	5,725	5,759	5,767	5,697	5,695	5,695	5,717	11,001	11,027	12,010
Total	1,476,373	66,333	67,168	68,596	70,409	71,828	71,797	72,182	72,479	71,811	72,872	73,919	75,165	76,034	76,641	77,459	78,021	77,491	78,100	78,571	79,496
Generation (GWH)																					
JB12 GC	977	0	0	0	525	281	118	127	245	59	12	1	0	0	0	0	0	97	0	0	0

Discount Rate
6.88%

P02a-MMGR-BDG-GC-MN ST Split Run Cost Data LT 9076 ST 20969

Total Is FOM Sample: Mean

$ millions	NPV	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1 Coal VOM Costs																					
Retired Coal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EOL Coal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2 Coal Fixed Costs																					
Retired Coal FOM	300	74	77	72	51	49	16	16	16	0	0	0	0	0	0	0	0	0	0	0	0
Reclamation Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Retirement Costs	243	0	0	0	52	0	124	0	41	12	37	0	0	0	0	0	0	63	128	0	43
EOL Coal FOM	2,489	211	246	246	272	264	269	264	225	208	237	232	247	238	255	247	251	174	136	128	106
Total	3,032	285	323	318	374	313	409	280	283	220	274	232	247	238	255	247	251	237	264	128	149
3 Coal Fuel Costs																					
Retired Coal	346	173	102	102	8	8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Retired Coal Start Fuel	11	4	4	4	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EOL Coal	4,514	403	416	421	503	497	463	475	431	449	416	424	435	417	428	435	459	370	220	226	194
EOL Coal Start Fuel	124	14	15	14	16	14	13	13	10	9	10	10	10	10	10	10	11	9	6	5	5
Total	4,995	593	537	541	528	519	476	489	440	457	426	434	445	428	438	445	469	379	226	231	199
4 Emission Cost (CO2)																					
Retired Coal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EOL Coal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5 Proxy Generation Costs																					
Solar VOM	23	(4)	(2)	4	4	4	4	4	4	4	4	4	4	4	4	4	4	1	1	0	0
Wind VOM	(3,441)	(309)	(311)	(333)	(335)	(481)	(534)	(554)	(545)	(573)	(586)	(211)	(219)	(206)	(203)	(52)	14	14	15	15	15
Gas VOM	108	11	14	16	15	10	7	7	8	7	7	6	6	5	6	6	6	13	16	16	18
Battery VOM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LT Contract VOM	871	108	109	129	127	110	100	99	98	95	64	36	36	35	35	35	34	29	28	28	28
QFs VOM	2,054	275	266	252	233	231	228	210	208	194	190	189	174	148	145	143	112	31	23	9	6
Other VOM	(57)	1	1	1	1	1	1	1	(36)	(36)	(35)	(35)	(36)	(35)	15	15	15	15	28	28	31
Fuel	2,439	271	304	309	298	208	156	165	194	181	161	161	150	126	145	150	167	283	348	370	436
Start Fuel	58	9	5	5	6	8	7	7	9	5	4	4	4	3	3	4	4	4	4	4	4
Energy not Served	15	1	0	8	0	0	2	2	0	1	2	2	2	1	0	1	3	0	0	0	0
Dumped Energy	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Deficiency Cost	103	50	39	24	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Emissions Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	2,173	412	424	414	352	91	(30)	(59)	(60)	(122)	(190)	155	121	80	149	306	359	389	463	470	538
VOM Integration, Wind + Solar																					
6 Proxy Generation Resource Fixed Costs																					
Generator Fixed / Build Costs	5,788	8	8	8	140	140	343	343	477	477	662	771	831	1,125	1,125	1,125	1,125	1,311	1,506	1,506	1,754
Battery Fixed / Build Costs	453	0	0	0	0	0	0	0	0	74	74	74	74	74	74	74	74	162	162	162	162
Solar FOM	1,762	0	0	0	92	129	154	157	168	169	211	234	239	293	299	303	310	349	350	355	374
Wind FOM	4,893	160	163	191	198	467	523	539	559	572	604	620	678	679	613	603	616	623	638	646	656
Gas FOM	438	36	38	38	40	41	42	43	46	49	52	54	55	33	34	34	35	36	37	37	37
Battery FOM	62	0	0	0	1	(1)	(1)	(2)	(0)	12	10	10	9	9	9	9	9	23	18	30	31
Other FOM	586	12	5	5	6	5	7	7	85	86	80	81	83	85	86	88	90	92	187	190	239
Use of Service	(6)	0	0	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(2)	(2)	(2)	(2)
Total	13,976	215	213	241	476	782	1,069	1,087	1,335	1,438	1,693	1,843	1,969	2,297	2,239	2,237	2,258	2,594	2,896	2,926	3,250
Remove Portfolio Credits																					
7 DSM Costs																					
DR VOM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DR FOM	610	0	6	19	29	34	38	42	46	51	55	60	63	86	90	105	117	138	157	166	230
EE VOM	1,085	9	21	30	40	50	60	74	88	103	121	138	153	167	181	195	205	221	240	260	276
EE FOM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	1,695	9	27	49	70	84	98	115	134	154	176	198	216	253	271	300	322	359	397	427	506
8 Market Costs																					
System Market Sales	(4,798)	(467)	(411)	(380)	(393)	(377)	(402)	(457)	(458)	(452)	(483)	(477)	(478)	(476)	(479)	(512)	(535)	(505)	(498)	(482)	(533)
System Market Purchases	718	88	80	83	65	46	30	34	44	50	52	55	52	51	56	57	62	95	128	134	188
Total	(4,080)	(379)	(331)	(296)	(328)	(331)	(372)	(422)	(413)	(402)	(431)	(422)	(426)	(424)	(422)	(455)	(473)	(410)	(370)	(349)	(345)
9 Transmission Costs																					
Transmission Build / Reinforcement Costs	1,341	0	0	0	1	99	151	151	157	157	159	177	199	214	214	214	214	256	256	256	296
Total	1,341	0	0	0	1	99	151	151	157	157	159	177	199	214	214	214	214	256	256	256	296

11	Total System Cost	22,944	1,135	1,193	1,266	1,472	1,528	1,771	1,613	1,847	1,874	2,078	2,588	2,742	3,055	3,186	3,263	3,371	3,775	4,101	4,060	4,561
	Fixed	18,959	500	542	578	881	1,228	1,666	1,561	1,822	1,867	2,181	2,312	2,478	2,834	2,798	2,802	2,841	3,225	3,573	3,477	3,924
	Variable	4,172	636	652	688	592	329	134	81	55	37	(74)	305	293	250	346	491	560	580	558	613	667
	Adjustments	(187)	0	(0)	(0)	(0)	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(30)	(30)	41	(30)	(30)	(30)	(30)	(30)	(30)
12	Risk Adjusted PVRR	23,123		179																		
	Generation (GWH)																					
	Retired Coal	17,366	7,374	5,213	4,234	275	270	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	EOL Coal	378,667	24,073	24,063	23,837	26,488	25,973	24,174	24,230	20,205	19,957	18,627	18,401	18,280	17,242	17,181	17,498	18,146	14,010	9,324	9,350	7,608
	DSM	147,104	2,446	2,936	3,450	3,985	4,452	4,930	5,500	6,116	6,731	7,357	7,907	8,409	8,826	9,288	9,733	9,986	10,423	11,033	11,570	12,027
	LT Contracts	32,362	1,441	1,685	2,597	3,063	2,434	2,264	2,229	2,213	2,149	1,656	1,204	1,185	1,172	1,160	1,145	1,132	925	914	904	891
	QFs	73,167	5,736	5,611	5,380	5,067	5,024	4,970	4,719	4,682	4,460	4,410	4,384	4,172	3,667	3,371	3,330	2,627	655	552	256	94
	Gas	153,630	11,013	13,361	14,471	13,220	8,481	6,144	6,258	6,813	6,046	5,256	5,092	4,650	3,687	4,235	4,318	4,681	7,656	9,124	9,220	9,902
	Solar	205,916	1,223	1,271	1,466	5,625	6,772	8,411	8,377	8,651	8,732	10,078	11,241	11,216	14,286	14,269	14,253	14,229	16,400	16,397	16,372	16,645
	Wind	362,281	9,171	9,219	9,709	10,018	15,818	18,228	18,232	18,372	18,345	20,122	20,118	21,660	21,559	21,586	21,598	21,710	21,646	21,651	21,644	21,875
	Other System	106,320	3,860	3,946	3,457	3,171	2,944	2,940	2,945	5,789	5,778	5,758	5,724	5,758	5,766	5,692	5,688	5,689	5,718	8,237	8,257	9,205
	Total	1,476,814	66,337	67,304	68,602	70,911	72,168	72,064	72,489	72,842	72,198	73,264	74,071	75,330	76,206	76,783	77,564	78,200	77,432	77,231	77,573	78,246

Discount Rate
6.88%

P02-MMGR-LN ST Split Run Cost Data LT 5230 ST 20591

Total Is FOM Sample: Mean

$ millions	NPV	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1 Coal VOM Costs																					
Retired Coal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EOL Coal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2 Coal Fixed Costs																					
Retired Coal FOM	426	77	94	79	67	63	30	30	32	13	13	13	13	14	13	13	14	17	0	0	0
Reclamation Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Retirement Costs	243	0	0	0	0	0	124	0	41	12	37	0	0	0	0	0	0	63	259	0	43
EOL Coal FOM	2,489	211	246	246	272	264	269	264	225	208	237	232	247	238	255	247	251	174	136	128	106
Total	3,158	289	339	325	339	327	423	294	299	234	287	245	260	252	268	260	265	254	395	128	149
3 Coal Fuel Costs																					
Retired Coal	396	170	88	100	29	24	13	10	13	8	11	5	4	0	0	0	0	5	0	0	0
Retired Coal Start Fuel	18	3	3	4	3	2	1	1	2	1	2	1	1	0	0	0	0	1	0	0	0
EOL Coal	3,312	325	358	355	396	338	310	336	297	286	232	235	235	289	317	359	397	321	180	187	162
EOL Coal Start Fuel	109	13	13	13	14	14	12	12	9	8	8	6	7	7	8	8	9	7	5	5	3
Total	3,834	511	463	472	442	378	336	359	321	302	253	248	247	296	325	367	406	334	184	192	165
4 Emission Cost (CO2)																					
Retired Coal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EOL Coal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5 Proxy Generation Costs																					
Solar VOM	23	(4)	(2)	4	4	4	4	4	4	4	4	4	4	4	4	4	4	1	1	0	0
Wind VOM	(3,444)	(310)	(312)	(333)	(335)	(481)	(535)	(554)	(545)	(573)	(586)	(211)	(219)	(206)	(203)	(52)	14	14	15	15	15
Gas VOM	166	14	17	18	19	17	16	15	16	17	17	16	16	12	12	10	10	16	15	16	18
Battery VOM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LT Contract VOM	871	108	109	129	127	110	100	99	98	95	64	36	36	35	35	35	34	29	28	28	28
QFs VOM	2,054	275	266	252	233	231	228	210	208	194	190	189	174	148	145	143	112	31	23	9	6
Other VOM	(46)	1	1	1	1	1	1	1	(36)	(35)	(35)	(35)	(36)	(35)	15	15	15	15	41	41	44
Fuel	2,407	216	220	241	236	221	209	213	218	241	241	236	244	197	201	181	180	249	243	252	297
Start Fuel	43	5	2	2	3	4	5	6	6	5	4	4	5	4	4	4	4	3	3	3	3
Energy not Served	16	3	0	8	0	0	1	2	0	1	2	2	2	1	0	1	3	0	0	0	0
Dumped Energy	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Deficiency Cost	111	50	36	25	13	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Emissions Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	2,201	358	337	346	301	109	29	(5)	(31)	(54)	(100)	240	226	160	213	342	377	357	370	364	410
VOM Integration, Wind + Solar																					
6 Proxy Generation Resource Fixed Costs																					
Generator Fixed / Build Costs	5,089	8	8	8	15	15	218	218	352	352	537	704	765	1,035	1,035	1,035	1,035	1,237	1,601	1,601	1,849
Battery Fixed / Build Costs	453	0	0	0	0	0	0	0	0	74	74	74	74	74	74	74	74	162	162	162	162
Solar FOM	1,593	0	0	0	63	100	125	128	139	140	181	220	225	280	285	289	295	344	344	350	368
Wind FOM	4,893	160	163	191	198	467	523	539	559	572	604	620	678	679	613	603	616	623	638	646	656
Gas FOM	438	36	38	38	40	41	42	43	46	49	52	54	55	33	34	34	35	36	37	37	37
Battery FOM	62	0	0	0	1	(1)	(1)	(2)	(0)	12	10	10	9	9	9	9	9	23	18	30	31
Other FOM	667	12	5	5	6	5	7	7	85	86	80	81	83	85	86	88	90	92	280	286	336
Use of Service	(6)	0	0	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(2)	(2)	(2)	(2)
Total	13,189	215	213	241	322	628	915	933	1,181	1,284	1,538	1,763	1,889	2,193	2,135	2,132	2,153	2,515	3,078	3,110	3,436
Remove Portfolio Credits																					
7 DSM Costs																					
DR VOM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DR FOM	610	0	6	19	29	34	38	42	46	51	55	60	63	86	90	105	117	138	157	166	230
EE VOM	1,085	9	21	30	40	50	60	74	88	103	121	138	153	167	181	195	205	221	240	260	276
EE FOM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	1,695	9	27	49	70	84	98	115	134	154	176	198	216	253	271	300	322	359	397	427	506
8 Market Costs																					
System Market Sales	(3,157)	(210)	(192)	(208)	(214)	(230)	(272)	(317)	(313)	(310)	(322)	(318)	(330)	(366)	(378)	(403)	(415)	(412)	(412)	(394)	(479)
System Market Purchases	545	69	52	60	52	46	30	31	38	45	48	48	46	41	44	44	47	65	70	73	107
Total	(2,612)	(142)	(140)	(148)	(162)	(184)	(242)	(286)	(276)	(265)	(274)	(270)	(284)	(325)	(334)	(359)	(368)	(347)	(341)	(321)	(371)
9 Transmission Costs																					
Transmission Build / Reinforcement Costs	1,341	0	0	0	1	99	151	151	157	157	159	177	199	214	214	214	214	256	256	256	296
Total	1,341	0	0	0	1	99	151	151	157	157	159	177	199	214	214	214	214	256	256	256	296

11 Total System Cost	22,620	1,240	1,239	1,284	1,312	1,413	1,681	1,533	1,757	1,783	2,009	2,572	2,724	3,012	3,133	3,226	3,339	3,700	4,309	4,127	4,560
Fixed	18,298	503	558	585	691	1,089	1,526	1,420	1,683	1,725	2,039	2,246	2,411	2,744	2,707	2,711	2,749	3,164	3,886	3,661	4,110
Variable	4,509	737	680	699	622	353	183	141	103	87	(0)	356	342	298	385	545	620	566	453	496	480
Adjustments	(187)	0	(0)	(0)	(0)	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(30)	(30)	41	(30)	(30)	(30)	(30)	(30)	(30)
12 Risk Adjusted PVRR	22,821		201																		
Generation (GWH)																					
Retired Coal	21,697	7,132	4,403	4,212	1,652	1,286	681	456	584	327	449	213	160	3	0	0	-	138	-	-	-
EOL Coal	274,282	19,324	20,501	19,888	20,347	17,450	16,069	17,143	13,637	12,243	10,136	9,807	9,520	11,697	12,593	14,348	15,565	12,117	7,687	7,807	6,404
DSM	147,261	2,454	2,954	3,447	3,996	4,486	4,960	5,530	6,138	6,731	7,359	7,908	8,411	8,828	9,289	9,733	9,986	10,423	11,033	11,570	12,026
LT Contracts	32,361	1,441	1,684	2,597	3,063	2,434	2,264	2,229	2,213	2,149	1,656	1,204	1,185	1,172	1,160	1,145	1,132	925	914	904	891
QFs	73,171	5,736	5,611	5,384	5,067	5,024	4,970	4,719	4,682	4,460	4,410	4,384	4,172	3,667	3,371	3,330	2,627	655	552	256	94
Gas	239,634	13,840	15,935	16,743	16,967	15,096	13,656	13,212	13,054	13,477	13,196	12,474	12,470	9,058	8,708	7,509	7,188	9,331	8,904	8,984	9,832
Solar	188,802	1,223	1,271	1,467	3,821	4,990	6,648	6,629	6,885	6,931	8,267	10,554	10,530	13,601	13,582	13,562	13,536	16,289	16,264	16,240	16,513
Wind	362,654	9,187	9,248	9,720	10,021	15,831	18,256	18,253	18,385	18,345	20,155	20,161	21,697	21,594	21,621	21,617	21,729	21,650	21,656	21,653	21,875
Other System	116,576	4,016	4,198	3,638	3,482	3,400	3,188	3,097	5,900	5,903	5,758	5,726	5,761	5,768	5,707	5,682	5,679	5,719	10,971	10,994	11,988
Total	1,456,439	64,352	65,805	67,095	68,415	69,998	70,693	71,267	71,477	70,567	71,387	72,431	73,906	75,388	76,031	76,925	77,442	77,246	77,982	78,408	79,623
Generation (GWH)																					
JB12 GC	3,754	0	0	0	1,501	1,236	681	456	584	327	449	213	160	3	0	0	0	138	0	0	0

Discount Rate
6.88%

P02a-MMGR-BDG-GC-LN ST Split Run Cost Data LT 9076 ST 23132

Total | Is FOM | Sample: | Mean

$ millions	NPV	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1 Coal VOM Costs																					
Retired Coal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EOL Coal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2 Coal Fixed Costs																					
Retired Coal FOM	300	74	77	72	51	49	16	16	16	0	0	0	0	0	0	0	0	0	0	0	0
Reclamation Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Retirement Costs	243	0	0	0	52	0	124	0	41	12	37	0	0	0	0	0	0	63	128	0	43
EOL Coal FOM	2,489	211	246	246	272	264	269	264	225	208	237	232	247	238	255	247	251	174	136	128	106
Total	3,032	285	323	318	374	313	409	280	283	220	274	232	247	238	255	247	251	237	264	128	149
3 Coal Fuel Costs																					
Retired Coal	328	170	96	98	4	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Retired Coal Start Fuel	9	3	3	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EOL Coal	3,250	324	350	357	391	334	300	323	286	269	211	230	229	281	314	354	389	320	189	198	168
EOL Coal Start Fuel	107	13	13	13	14	12	12	12	9	7	7	7	7	7	7	8	9	7	5	5	4
Total	3,694	511	463	471	409	347	312	335	295	276	218	237	236	288	321	363	398	327	193	203	172
4 Emission Cost (CO2)																					
Retired Coal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EOL Coal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5 Proxy Generation Costs																					
Solar VOM	23	(4)	(2)	4	4	4	4	4	4	4	4	4	4	4	4	4	4	1	1	0	0
Wind VOM	(3,444)	(310)	(312)	(332)	(336)	(481)	(535)	(554)	(545)	(573)	(586)	(211)	(219)	(206)	(203)	(52)	14	14	15	15	15
Gas VOM	166	14	17	18	19	17	15	15	15	16	16	16	16	12	12	10	10	16	18	18	20
Battery VOM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LT Contract VOM	870	108	109	129	127	110	100	99	98	95	64	36	36	35	35	35	34	29	28	28	28
QFs VOM	2,054	275	266	252	233	231	228	210	208	194	190	189	174	148	145	143	112	31	23	9	6
Other VOM	(57)	1	1	1	1	1	1	1	(36)	(35)	(35)	(35)	(36)	(35)	15	15	15	15	28	28	31
Fuel	2,419	216	220	241	238	221	206	210	214	234	237	234	242	194	194	176	177	248	279	289	339
Start Fuel	41	5	2	2	3	4	4	5	5	4	4	4	5	4	4	4	4	3	3	3	4
Energy not Served	16	2	0	8	0	0	1	2	0	1	2	2	2	1	0	1	3	0	0	0	0
Dumped Energy	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Deficiency Cost	106	51	40	24	3	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Emissions Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	2,194	357	341	346	292	108	25	(10)	(36)	(62)	(104)	238	223	156	206	336	372	357	395	390	441
VOM Integration, Wind + Solar																					
6 Proxy Generation Resource Fixed Costs																					
Generator Fixed / Build Costs	5,788	8	8	8	140	140	343	343	477	477	662	771	831	1,125	1,125	1,125	1,125	1,311	1,506	1,506	1,754
Battery Fixed / Build Costs	453	0	0	0	0	0	0	0	0	74	74	74	74	74	74	74	74	162	162	162	162
Solar FOM	1,762	0	0	0	92	129	154	157	168	169	211	234	239	293	299	303	310	349	350	355	374
Wind FOM	4,893	160	163	191	198	467	523	539	559	572	604	620	678	679	613	603	616	623	638	646	656
Gas FOM	438	36	38	38	40	41	42	43	46	49	52	54	55	33	34	34	35	36	37	37	37
Battery FOM	62	0	0	0	1	(1)	(1)	(2)	(0)	12	10	10	9	9	9	9	9	23	18	30	31
Other FOM	586	12	5	5	6	5	7	7	85	86	80	81	83	85	86	88	90	92	187	190	239
Use of Service	(6)	0	0	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(2)	(2)	(2)	(2)
Total	13,976	215	213	241	476	782	1,069	1,087	1,335	1,438	1,693	1,843	1,969	2,297	2,239	2,237	2,258	2,594	2,896	2,926	3,250
Remove Portfolio Credits																					
7 DSM Costs																					
DR VOM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DR FOM	610	0	6	19	29	34	38	42	46	51	55	60	63	86	90	105	117	138	157	166	230
EE VOM	1,085	9	21	30	40	50	60	74	88	103	121	138	153	167	181	195	205	221	240	260	276
EE FOM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	1,695	9	27	49	70	84	98	115	134	154	176	198	216	253	271	300	322	359	397	427	506
8 Market Costs																					
System Market Sales	(3,142)	(210)	(193)	(208)	(217)	(232)	(274)	(320)	(315)	(311)	(323)	(316)	(329)	(367)	(379)	(404)	(416)	(407)	(391)	(373)	(441)
System Market Purchases	551	69	51	60	48	41	28	30	35	44	48	48	46	41	43	43	46	68	88	92	133
Total	(2,591)	(141)	(141)	(147)	(169)	(191)	(246)	(290)	(279)	(267)	(274)	(269)	(283)	(326)	(335)	(361)	(370)	(340)	(303)	(281)	(308)
9 Transmission Costs																					
Transmission Build / Reinforcement Costs	1,341	0	0	0	1	99	151	151	157	157	159	177	199	214	214	214	214	256	256	256	296
Total	1,341	0	0	0	1	99	151	151	157	157	159	177	199	214	214	214	214	256	256	256	296

11	Total System Cost	23,154	1,236	1,226	1,278	1,453	1,513	1,788	1,641	1,860	1,888	2,112	2,627	2,779	3,090	3,212	3,305	3,416	3,761	4,068	4,019	4,475
	Fixed	18,959	500	542	578	881	1,228	1,666	1,561	1,822	1,867	2,181	2,312	2,478	2,834	2,798	2,802	2,841	3,225	3,573	3,477	3,924
	Variable	4,382	736	684	700	572	313	151	109	68	50	(40)	344	330	286	373	533	605	566	525	572	581
	Adjustments	(187)	0	(0)	(0)	(0)	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(30)	(30)	41	(30)	(30)	(30)	(30)	(30)	(30)
12	Risk Adjusted PVRR	23,350		196																		
	Generation (GWH)																					
	Retired Coal	16,231	7,158	4,782	4,092	161	38	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	EOL Coal	269,101	19,306	20,147	19,970	20,096	17,236	15,420	16,361	13,056	11,440	9,226	9,526	9,255	11,349	12,370	14,058	15,231	12,075	8,090	8,226	6,661
	DSM	147,172	2,454	2,956	3,449	3,991	4,463	4,942	5,510	6,112	6,731	7,359	7,908	8,409	8,828	9,289	9,733	9,986	10,423	11,033	11,570	12,027
	LT Contracts	32,356	1,440	1,684	2,592	3,063	2,434	2,264	2,229	2,213	2,149	1,656	1,204	1,185	1,172	1,160	1,145	1,132	925	914	904	891
	QFs	73,169	5,736	5,611	5,382	5,067	5,024	4,970	4,719	4,682	4,460	4,410	4,384	4,172	3,667	3,371	3,330	2,627	655	552	256	94
	Gas	240,715	13,830	15,949	16,757	16,965	14,991	13,426	12,904	12,693	13,079	12,957	12,366	12,332	8,882	8,430	7,284	7,047	9,301	10,228	10,291	11,004
	Solar	205,986	1,223	1,271	1,467	5,635	6,760	8,410	8,385	8,664	8,753	10,089	11,246	11,223	14,291	14,273	14,253	14,229	16,400	16,397	16,372	16,645
	Wind	362,583	9,187	9,250	9,681	10,042	15,843	18,269	18,267	18,382	18,345	20,151	20,152	21,681	21,579	21,607	21,601	21,720	21,647	21,654	21,650	21,875
	Other System	108,433	4,020	4,184	3,645	3,552	3,445	3,184	3,132	5,945	5,903	5,758	5,725	5,760	5,769	5,700	5,670	5,671	5,719	8,222	8,238	9,190
	Total	1,455,748	64,354	65,835	67,036	68,571	70,234	70,887	71,507	71,746	70,860	71,606	72,512	74,017	75,537	76,200	77,074	77,642	77,144	77,091	77,507	78,386

Discount Rate
6.88%

P02-MMGR-HH ST Split Run Cost Data LT 5230 ST 20570

Total Is FOM Sample: Mean

$ millions	NPV	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1 Coal VOM Costs																					
Retired Coal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EOL Coal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2 Coal Fixed Costs																					
Retired Coal FOM	426	77	94	79	67	63	30	30	32	13	13	13	13	14	13	13	14	17	0	0	0
Reclamation Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Retirement Costs	243	0	0	0	0	0	124	0	41	12	37	0	0	0	0	0	0	63	259	0	43
EOL Coal FOM	2,489	211	246	246	272	264	269	264	225	208	237	232	247	238	255	247	251	174	136	128	106
Total	3,158	289	339	325	339	327	423	294	299	234	287	245	260	252	268	260	265	254	395	128	149
3 Coal Fuel Costs																					
Retired Coal	431	171	97	117	24	17	7	9	12	7	2	11	8	9	17	14	19	23	0	0	0
Retired Coal Start Fuel	26	4	4	4	3	3	2	2	3	1	1	2	2	1	2	2	2	2	0	0	0
EOL Coal	3,119	422	459	469	538	366	318	319	285	257	183	163	160	154	147	141	150	138	34	32	26
EOL Coal Start Fuel	126	13	15	15	15	17	16	17	14	11	13	8	7	7	7	6	8	7	3	3	3
Total	3,703	610	575	605	580	403	342	347	314	277	200	184	178	171	173	164	180	171	37	35	29
4 Emission Cost (CO2)																					
Retired Coal	39	0	0	0	0	10	3	4	5	3	1	5	4	5	9	8	12	16	0	0	0
EOL Coal	2,478	0	0	0	0	460	433	467	420	377	300	275	286	295	300	309	364	353	123	124	106
Total	2,517	0	0	0	0	470	436	471	425	380	301	280	290	300	309	317	376	369	123	124	106
5 Proxy Generation Costs																					
Solar VOM	23	(4)	(2)	4	4	4	4	4	4	4	4	4	4	4	4	4	4	1	1	0	0
Wind VOM	(3,443)	(309)	(310)	(332)	(334)	(482)	(536)	(555)	(546)	(573)	(586)	(211)	(219)	(206)	(203)	(51)	14	14	15	15	15
Gas VOM	149	10	11	12	11	14	14	14	14	15	17	16	16	15	15	16	17	18	16	17	17
Battery VOM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LT Contract VOM	871	108	109	129	127	110	100	99	98	95	64	36	36	35	35	35	34	29	28	28	28
QFs VOM	2,054	275	266	252	233	231	228	210	208	194	190	189	174	148	145	143	112	31	23	9	6
Other VOM	(44)	1	1	1	1	1	1	1	(36)	(35)	(35)	(35)	(36)	(35)	15	15	15	15	43	43	46
Fuel	4,380	267	322	350	320	371	360	393	390	437	474	470	487	471	512	537	558	539	495	517	544
Start Fuel	100	11	9	9	11	9	9	10	12	9	8	8	10	9	10	11	9	7	6	6	6
Energy not Served	15	1	0	8	0	0	2	2	0	1	1	2	2	1	0	1	3	0	0	0	0
Dumped Energy	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Deficiency Cost	102	50	35	25	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Emissions Costs	1,653	0	0	0	0	127	130	148	155	181	209	219	241	235	268	304	343	353	341	388	412
Total	5,860	410	439	458	378	387	311	325	300	326	346	698	715	676	801	1,015	1,109	1,007	968	1,024	1,074
VOM Integration, Wind + Solar																					
6 Proxy Generation Resource Fixed Costs																					
Generator Fixed / Build Costs	5,089	8	8	8	15	15	218	218	352	352	537	704	765	1,035	1,035	1,035	1,035	1,237	1,601	1,601	1,849
Battery Fixed / Build Costs	453	0	0	0	0	0	0	0	0	74	74	74	74	74	74	74	74	162	162	162	162
Solar FOM	1,593	0	0	0	63	100	125	128	139	140	181	220	225	280	285	289	295	344	344	350	368
Wind FOM	4,893	160	163	191	198	467	523	539	559	572	604	620	678	679	613	603	616	623	638	646	656
Gas FOM	438	36	38	38	40	41	42	43	46	49	52	54	55	33	34	34	35	36	37	37	37
Battery FOM	62	0	0	0	1	(1)	(1)	(2)	(0)	12	10	10	9	9	9	9	9	23	18	30	31
Other FOM	667	12	5	5	6	5	7	7	85	86	80	81	83	85	86	88	90	92	280	286	336
Use of Service	(6)	0	0	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(2)	(2)	(2)	(2)
Total	13,189	215	213	241	322	628	915	933	1,181	1,284	1,538	1,763	1,889	2,193	2,135	2,132	2,153	2,515	3,078	3,110	3,436
Remove Portfolio Credits																					
7 DSM Costs																					
DR VOM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DR FOM	610	0	6	19	29	34	38	42	46	51	55	60	63	86	90	105	117	138	157	166	230
EE VOM	1,085	9	21	30	40	50	60	74	88	103	121	138	153	167	181	195	205	221	240	260	276
EE FOM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	1,695	9	27	49	70	84	98	115	134	154	176	198	216	253	271	300	322	359	397	427	506
8 Market Costs																					
System Market Sales	(4,553)	(292)	(290)	(326)	(325)	(357)	(423)	(481)	(487)	(473)	(485)	(494)	(507)	(523)	(518)	(517)	(529)	(507)	(509)	(502)	(576)
System Market Purchases	2,085	84	91	93	98	152	136	139	150	193	206	227	236	245	286	314	355	401	415	446	521
Total	(2,468)	(208)	(199)	(232)	(227)	(205)	(288)	(341)	(337)	(280)	(279)	(267)	(271)	(277)	(232)	(203)	(173)	(106)	(93)	(56)	(56)
9 Transmission Costs																					
Transmission Build / Reinforcement Costs	1,341	0	0	0	1	99	151	151	157	157	159	177	199	214	214	214	214	256	256	256	296
Total	1,341	0	0	0	1	99	151	151	157	157	159	177	199	214	214	214	214	256	256	256	296

11 Total System Cost	28,807	1,324	1,394	1,446	1,462	2,164	2,359	2,266	2,443	2,502	2,698	3,249	3,446	3,750	3,980	4,168	4,416	4,797	5,131	5,019	5,509
Fixed	18,298	503	558	585	691	1,089	1,526	1,420	1,683	1,725	2,039	2,246	2,411	2,744	2,707	2,711	2,749	3,164	3,886	3,661	4,110
Variable	10,697	821	836	861	771	1,104	861	875	789	806	689	1,033	1,065	1,036	1,232	1,487	1,697	1,663	1,275	1,388	1,429
Adjustments	(187)	0	(0)	(0)	(0)	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(30)	(30)	41	(30)	(30)	(30)	(30)	(30)	(30)
12 Risk Adjusted PVRR	29,308		501																		
Generation (GWH)																					
Retired Coal	20,814	7,279	4,902	5,126	639	432	154	187	253	135	48	213	150	151	270	222	296	358	-	-	-
EOL Coal	226,056	24,948	26,322	26,175	28,375	18,162	15,526	15,223	12,787	10,542	7,524	6,281	5,902	5,472	5,025	4,672	4,971	4,380	1,440	1,314	1,015
DSM	146,998	2,413	2,908	3,365	3,980	4,484	4,931	5,500	6,115	6,732	7,359	7,909	8,411	8,829	9,290	9,733	9,986	10,423	11,033	11,570	12,027
LT Contracts	32,363	1,441	1,685	2,597	3,063	2,434	2,264	2,229	2,213	2,149	1,656	1,204	1,185	1,172	1,160	1,145	1,132	925	914	904	891
QFs	73,171	5,736	5,611	5,384	5,067	5,024	4,970	4,719	4,682	4,460	4,410	4,384	4,172	3,667	3,371	3,330	2,627	655	552	256	94
Gas	221,263	9,517	10,511	11,061	10,276	12,353	11,480	11,908	11,284	12,164	12,827	12,180	12,054	10,650	10,935	11,256	11,493	10,814	9,462	9,718	9,321
Solar	188,589	1,223	1,271	1,467	3,787	4,993	6,573	6,564	6,844	6,932	8,266	10,554	10,529	13,603	13,584	13,560	13,535	16,289	16,264	16,239	16,513
Wind	362,853	9,162	9,209	9,686	9,989	15,878	18,300	18,304	18,393	18,345	20,176	20,183	21,718	21,617	21,636	21,646	21,752	21,662	21,661	21,661	21,874
Other System	114,063	3,683	3,651	3,161	3,087	2,958	2,980	2,965	5,790	5,802	5,756	5,722	5,759	5,766	5,720	5,729	5,723	5,746	11,061	11,082	11,922
Total	1,386,170	65,402	66,071	68,023	68,262	66,719	67,179	67,599	68,362	67,259	68,021	68,631	69,880	70,926	70,990	71,294	71,514	71,251	72,387	72,744	73,656
Generation (GWH)																					
JB12 GC	1,597	0	0	0	360	298	154	187	253	135	48	213	150	151	270	222	296	358	0	0	0

Discount Rate
6.88%

P02a-MMGR-BDG-GC-HH ST Split Run Cost Data LT 9076 ST 20927

Total Is FOM Sample: Mean

$ millions	NPV	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1 Coal VOM Costs																					
Retired Coal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EOL Coal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2 Coal Fixed Costs																					
Retired Coal FOM	300	74	77	72	51	49	16	16	16	0	0	0	0	0	0	0	0	0	0	0	0
Reclamation Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Retirement Costs	243	0	0	0	52	0	124	0	41	12	37	0	0	0	0	0	0	63	128	0	43
EOL Coal FOM	2,489	211	246	246	272	264	269	264	225	208	237	232	247	238	255	247	251	174	136	128	106
Total	3,032	285	323	318	374	313	409	280	283	220	274	232	247	238	255	247	251	237	264	128	149
3 Coal Fuel Costs																					
Retired Coal	352	170	104	115	8	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Retired Coal Start Fuel	11	4	4	4	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EOL Coal	3,051	422	452	471	531	354	301	301	272	239	161	159	156	150	145	136	144	137	50	43	36
EOL Coal Start Fuel	121	14	15	15	16	16	15	15	11	9	10	7	7	7	7	6	8	8	4	4	3
Total	3,535	609	575	606	555	372	316	316	284	248	171	167	163	156	152	143	152	145	54	47	39
4 Emission Cost (CO2)																					
Retired Coal	2	0	0	0	0	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EOL Coal	2,397	0	0	0	0	441	408	437	399	349	260	266	277	285	295	299	347	349	182	168	150
Total	2,400	0	0	0	0	445	408	437	399	349	260	266	277	285	295	299	347	349	182	168	150
5 Proxy Generation Costs																					
Solar VOM	23	(4)	(2)	4	4	4	4	4	4	4	4	4	4	4	4	4	4	1	1	0	0
Wind VOM	(3,443)	(309)	(310)	(332)	(334)	(482)	(536)	(555)	(546)	(573)	(586)	(211)	(219)	(206)	(203)	(51)	14	14	15	15	15
Gas VOM	149	10	11	12	11	14	13	14	13	14	16	16	16	14	15	16	16	18	18	19	18
Battery VOM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LT Contract VOM	871	108	109	129	127	110	100	99	98	95	64	36	36	35	35	35	34	29	28	28	28
QFs VOM	2,054	275	266	252	233	231	228	210	208	194	190	189	174	148	145	143	112	31	23	9	6
Other VOM	(53)	1	1	1	1	1	1	1	(36)	(35)	(35)	(35)	(36)	(35)	15	15	15	16	29	31	36
Fuel	4,385	267	321	351	307	365	352	386	375	417	458	470	482	458	505	530	550	549	554	597	651
Start Fuel	96	11	9	9	9	8	8	9	11	8	8	9	10	9	10	10	9	7	6	7	8
Energy not Served	18	2	0	8	0	0	1	2	0	1	2	2	2	1	0	10	3	0	0	0	0
Dumped Energy	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Deficiency Cost	103	50	39	24	2	1	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0
Emissions Costs	1,659	0	0	0	0	124	126	145	148	172	202	219	238	228	261	297	336	353	381	431	457
Total	5,862	410	443	457	361	377	299	314	277	296	322	698	707	656	787	1,008	1,095	1,018	1,056	1,137	1,219
VOM Integration, Wind + Solar																					
6 Proxy Generation Resource Fixed Costs																					
Generator Fixed / Build Costs	5,788	8	8	8	140	140	343	343	477	477	662	771	831	1,125	1,125	1,125	1,125	1,311	1,506	1,506	1,754
Battery Fixed / Build Costs	453	0	0	0	0	0	0	0	0	74	74	74	74	74	74	74	74	162	162	162	162
Solar FOM	1,762	0	0	0	92	129	154	157	168	169	211	234	239	293	299	303	310	349	350	355	374
Wind FOM	4,893	160	163	191	198	467	523	539	559	572	604	620	678	679	613	603	616	623	638	646	656
Gas FOM	438	36	38	38	40	41	42	43	46	49	52	54	55	33	34	34	35	36	37	37	37
Battery FOM	62	0	0	0	1	(1)	(1)	(2)	(0)	12	10	10	9	9	9	9	9	23	18	30	31
Other FOM	586	12	5	5	6	5	7	7	85	86	80	81	83	85	86	88	90	92	187	190	239
Use of Service	(6)	0	0	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(2)	(2)	(2)	(2)
Total	13,976	215	213	241	476	782	1,069	1,087	1,335	1,438	1,693	1,843	1,969	2,297	2,239	2,237	2,258	2,594	2,896	2,926	3,250
Remove Portfolio Credits																					
7 DSM Costs																					
DR VOM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DR FOM	610	0	6	19	29	34	38	42	46	51	55	60	63	86	90	105	117	138	157	166	230
EE VOM	1,085	9	21	30	40	50	60	74	88	103	121	138	153	167	181	195	205	221	240	260	276
EE FOM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	1,695	9	27	49	70	84	98	115	134	154	176	198	216	253	271	300	322	359	397	427	506
8 Market Costs																					
System Market Sales	(4,513)	(292)	(291)	(326)	(337)	(370)	(433)	(487)	(492)	(479)	(489)	(492)	(506)	(512)	(504)	(506)	(506)	(477)	(475)	(443)	(505)
System Market Purchases	2,086	84	89	94	86	138	123	131	141	184	201	224	233	250	290	319	365	417	450	496	563
Total	(2,427)	(207)	(201)	(233)	(251)	(232)	(310)	(356)	(352)	(294)	(287)	(269)	(273)	(263)	(213)	(186)	(141)	(60)	(25)	53	59
9 Transmission Costs																					
Transmission Build / Reinforcement Costs	1,341	0	0	0	1	99	151	151	157	157	159	177	199	214	214	214	214	256	256	256	296
Total	1,341	0	0	0	1	99	151	151	157	157	159	177	199	214	214	214	214	256	256	256	296

11	Total System Cost	29,226	1,321	1,381	1,437	1,586	2,211	2,411	2,318	2,487	2,540	2,738	3,282	3,476	3,807	4,041	4,230	4,469	4,868	5,051	5,112	5,637
	Fixed	18,959	500	542	578	881	1,228	1,666	1,561	1,822	1,867	2,181	2,312	2,478	2,834	2,798	2,802	2,841	3,225	3,573	3,477	3,924
	Variable	10,454	821	839	860	705	1,012	774	786	695	702	586	999	1,027	1,002	1,202	1,458	1,658	1,673	1,508	1,665	1,743
	Adjustments	(187)	0	(0)	(0)	(0)	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(30)	(30)	41	(30)	(30)	(30)	(30)	(30)	(30)
12	Risk Adjusted PVRR	29,712		487																		
	Generation (GWH)																					
	Retired Coal	17,938	7,264	5,293	5,022	277	81	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	EOL Coal	220,966	24,973	26,003	26,278	27,924	17,482	14,671	14,279	12,158	9,758	6,536	6,075	5,710	5,282	4,932	4,509	4,726	4,324	2,131	1,775	1,439
	DSM	146,867	2,413	2,910	3,369	3,958	4,451	4,905	5,473	6,091	6,731	7,359	7,908	8,409	8,828	9,289	9,733	9,986	10,423	11,033	11,570	12,027
	LT Contracts	32,363	1,441	1,685	2,597	3,063	2,434	2,264	2,229	2,213	2,149	1,656	1,204	1,185	1,172	1,160	1,145	1,132	925	914	904	891
	QFs	73,171	5,736	5,611	5,384	5,067	5,024	4,970	4,719	4,682	4,460	4,410	4,384	4,172	3,667	3,371	3,330	2,627	655	552	256	94
	Gas	220,686	9,499	10,508	11,088	9,924	12,185	11,256	11,694	10,803	11,643	12,384	12,094	11,874	10,345	10,656	10,981	11,278	10,809	10,560	10,768	10,338
	Solar	205,721	1,223	1,271	1,467	5,576	6,754	8,333	8,317	8,608	8,755	10,090	11,246	11,221	14,292	14,275	14,252	14,228	16,400	16,397	16,372	16,644
	Wind	362,832	9,162	9,201	9,692	9,998	15,885	18,301	18,305	18,388	18,345	20,173	20,180	21,711	21,610	21,629	21,642	21,751	21,662	21,661	21,661	21,875
	Other System	105,893	3,681	3,649	3,162	3,059	2,951	2,962	2,965	5,805	5,798	5,756	5,724	5,759	5,767	5,734	5,736	5,725	5,771	8,291	8,354	9,244
	Total	1,386,438	65,391	66,132	68,059	68,846	67,246	67,664	67,982	68,749	67,639	68,363	68,816	70,042	70,963	71,046	71,328	71,452	70,969	71,540	71,660	72,551

Discount Rate
6.88%

P02-MMGR-SC ST Split Run Cost Data LT 5230 ST 20633

Total | Is FOM | Sample: | Mean

$ millions	NPV	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1 Coal VOM Costs																					
Retired Coal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EOL Coal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2 Coal Fixed Costs																					
Retired Coal FOM	426	77	94	79	67	63	30	30	32	13	13	13	13	14	13	13	14	17	0	0	0
Reclamation Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Retirement Costs	243	0	0	0	0	0	124	0	41	12	37	0	0	0	0	0	0	63	259	0	43
EOL Coal FOM	2,489	211	246	246	272	264	269	264	225	208	237	232	247	238	255	247	251	174	136	128	106
Total	3,158	289	339	325	339	327	423	294	299	234	287	245	260	252	268	260	265	254	395	128	149
3 Coal Fuel Costs																					
Retired Coal	756	82	53	49	116	122	90	91	66	75	69	66	58	52	57	64	85	86	0	0	0
Retired Coal Start Fuel	59	7	7	9	4	5	6	6	5	5	6	5	5	5	5	6	8	6	0	0	0
EOL Coal	816	197	199	196	132	76	41	45	33	31	19	12	10	7	9	12	15	18	9	9	15
EOL Coal Start Fuel	216	33	35	36	49	37	21	20	22	11	7	4	4	2	2	3	4	3	1	1	2
Total	1,846	319	293	290	301	240	158	162	126	122	101	87	77	66	74	84	112	113	10	10	17
4 Emission Cost (CO2)																					
Retired Coal	1,547	286	223	185	188	198	145	148	104	112	104	98	88	78	87	99	134	137	0	0	0
EOL Coal	3,902	901	926	929	667	374	197	218	169	142	87	58	49	34	46	62	82	85	54	54	90
Total	5,449	1,188	1,149	1,114	854	573	342	366	273	254	191	156	136	112	133	161	215	222	54	54	90
5 Proxy Generation Costs																					
Solar VOM	23	(4)	(2)	4	4	4	4	4	4	4	4	4	4	4	4	4	4	1	1	0	0
Wind VOM	(3,457)	(314)	(314)	(336)	(338)	(482)	(536)	(555)	(546)	(573)	(586)	(211)	(219)	(206)	(203)	(51)	14	14	15	15	15
Gas VOM	181	15	17	18	18	17	16	17	17	17	17	17	17	16	17	17	18	19	16	17	17
Battery VOM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LT Contract VOM	871	108	109	129	127	110	100	99	98	95	64	36	36	35	35	35	34	29	28	28	28
QFs VOM	2,054	275	266	252	233	231	228	210	208	194	190	189	174	148	145	143	112	31	23	9	6
Other VOM	(41)	1	1	1	1	1	1	1	(36)	(35)	(35)	(35)	(36)	(35)	15	15	15	15	46	48	47
Fuel	4,376	364	409	396	435	414	386	404	401	430	416	412	424	400	409	418	430	415	403	458	455
Start Fuel	78	8	5	5	6	8	8	9	11	8	8	8	8	7	8	8	7	5	5	6	6
Energy not Served	43	11	0	8	2	0	1	2	0	1	0	2	2	0	0	1	3	0	0	0	69
Dumped Energy	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Deficiency Cost	184	73	52	42	20	11	5	11	4	0	0	0	0	0	0	0	0	0	0	0	1
Emissions Costs	6,744	545	640	692	682	650	619	649	627	632	615	610	638	591	621	650	679	658	562	603	615
Total	11,055	1,082	1,182	1,211	1,192	964	831	848	789	771	693	1,031	1,048	961	1,050	1,240	1,316	1,188	1,100	1,185	1,258
VOM Integration, Wind + Solar																					
6 Proxy Generation Resource Fixed Costs																					
Generator Fixed / Build Costs	5,089	8	8	8	15	15	218	218	352	352	537	704	765	1,035	1,035	1,035	1,035	1,237	1,601	1,601	1,849
Battery Fixed / Build Costs	453	0	0	0	0	0	0	0	0	74	74	74	74	74	74	74	74	162	162	162	162
Solar FOM	1,593	0	0	0	63	100	125	128	139	140	181	220	225	280	285	289	295	344	344	350	368
Wind FOM	4,893	160	163	191	198	467	523	539	559	572	604	620	678	679	613	603	616	623	638	646	656
Gas FOM	438	36	38	38	40	41	42	43	46	49	52	54	55	33	34	34	35	36	37	37	37
Battery FOM	62	0	0	0	1	(1)	(1)	(2)	(0)	12	10	10	9	9	9	9	9	23	18	30	31
Other FOM	667	12	5	5	6	5	7	7	85	86	80	81	83	85	86	88	90	92	280	286	336
Use of Service	(6)	0	0	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(2)	(2)	(2)	(2)
Total	13,189	215	213	241	322	628	915	933	1,181	1,284	1,538	1,763	1,889	2,193	2,135	2,132	2,153	2,515	3,078	3,110	3,436
Remove Portfolio Credits																					
7 DSM Costs																					
DR VOM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DR FOM	610	0	6	19	29	34	38	42	46	51	55	60	63	86	90	105	117	138	157	166	230
EE VOM	1,085	9	21	30	40	50	60	74	88	103	121	138	153	167	181	195	205	221	240	260	276
EE FOM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	1,695	9	27	49	70	84	98	115	134	154	176	198	216	253	271	300	322	359	397	427	506
8 Market Costs																					
System Market Sales	(3,004)	(154)	(159)	(144)	(164)	(180)	(229)	(243)	(278)	(299)	(316)	(360)	(388)	(411)	(410)	(431)	(425)	(423)	(464)	(455)	(599)
System Market Purchases	5,126	428	485	497	499	481	474	478	470	495	468	450	446	431	455	464	519	538	517	533	576
Total	2,122	274	326	352	335	300	245	235	192	196	151	90	58	20	46	33	94	115	52	78	(23)
9 Transmission Costs																					
Transmission Build / Reinforcement Costs	1,341	0	0	0	1	99	151	151	157	157	159	177	199	214	214	214	214	256	256	256	296
Total	1,341	0	0	0	1	99	151	151	157	157	159	177	199	214	214	214	214	256	256	256	296

11 Total System Cost	39,667	3,374	3,529	3,582	3,414	3,187	3,134	3,076	3,122	3,143	3,267	3,718	3,854	4,040	4,232	4,393	4,661	4,994	5,312	5,218	5,698
Fixed	18,298	503	558	585	691	1,089	1,526	1,420	1,683	1,725	2,039	2,246	2,411	2,744	2,707	2,711	2,749	3,164	3,886	3,661	4,110
Variable	21,556	2,871	2,970	2,996	2,723	2,127	1,637	1,685	1,468	1,447	1,258	1,502	1,472	1,326	1,484	1,713	1,942	1,860	1,456	1,587	1,618
Adjustments	(187)	0	(0)	(0)	(0)	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(30)	(30)	41	(30)	(30)	(30)	(30)	(30)	(30)
12 Risk Adjusted PVRR	40,693		1027																		
Generation (GWH)																					
Retired Coal	35,165	3,254	2,517	1,932	3,691	3,602	2,596	2,557	1,745	1,836	1,631	1,501	1,294	1,104	1,190	1,301	1,702	1,712	-	-	-
EOL Coal	53,398	10,650	10,468	10,102	6,857	3,570	1,815	1,969	1,452	1,263	745	493	394	279	361	471	596	589	377	361	586
DSM	147,065	2,447	2,947	3,433	3,982	4,456	4,917	5,482	6,100	6,731	7,359	7,909	8,411	8,828	9,291	9,733	9,986	10,423	11,033	11,570	12,028
LT Contracts	32,375	1,445	1,689	2,601	3,063	2,434	2,264	2,229	2,213	2,149	1,656	1,204	1,185	1,172	1,160	1,145	1,132	925	914	904	891
QFs	73,171	5,736	5,611	5,384	5,067	5,024	4,970	4,719	4,682	4,460	4,410	4,384	4,172	3,667	3,371	3,330	2,627	655	552	256	94
Gas	262,036	14,480	16,231	16,732	16,762	15,177	14,299	14,580	13,849	13,917	13,286	12,764	12,847	11,640	11,784	11,909	12,039	11,334	9,321	9,623	9,462
Solar	188,262	1,223	1,271	1,467	3,774	4,903	6,498	6,467	6,796	6,931	8,266	10,554	10,529	13,601	13,581	13,560	13,535	16,289	16,264	16,239	16,513
Wind	363,594	9,370	9,388	9,843	10,154	15,897	18,310	18,309	18,385	18,345	20,177	20,184	21,719	21,618	21,638	21,647	21,752	21,662	21,660	21,661	21,874
Other System	119,330	4,407	4,602	4,198	3,705	3,563	3,321	3,296	6,001	5,951	5,758	5,725	5,762	5,769	5,723	5,727	5,728	5,745	11,151	11,237	11,961
Total	1,274,397	53,013	54,724	55,692	57,056	58,626	58,990	59,607	61,224	61,583	63,288	64,719	66,311	67,680	68,099	68,823	69,096	69,333	71,273	71,852	73,408
Generation (GWH)																					
JB12 GC	15,467	0	0	0	3,688	3,579	2,596	2,557	1,745	1,836	1,631	1,501	1,294	1,104	1,190	1,301	1,702	1,712	0	0	0

Discount Rate
6.88%

P02a-MMGR-BDG-GC-SC ST Split Run Cost Data LT 9076 ST 20990

Total Is FOM Sample: Mean

$ millions	NPV	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1 Coal VOM Costs																					
Retired Coal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EOL Coal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2 Coal Fixed Costs																					
Retired Coal FOM	300	74	77	72	51	49	16	16	16	0	0	0	0	0	0	0	0	0	0	0	0
Reclamation Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Retirement Costs	243	0	0	0	52	0	124	0	41	12	37	0	0	0	0	0	0	63	128	0	43
EOL Coal FOM	2,489	211	246	246	272	264	269	264	225	208	237	232	247	238	255	247	251	174	136	128	106
Total	3,032	285	323	318	374	313	409	280	283	220	274	232	247	238	255	247	251	237	264	128	149
3 Coal Fuel Costs																					
Retired Coal	164	84	53	47	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Retired Coal Start Fuel	20	7	7	9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EOL Coal	968	196	199	196	164	103	57	63	44	46	36	31	27	24	27	31	45	40	19	17	20
EOL Coal Start Fuel	201	33	34	37	37	32	18	17	18	8	7	6	6	5	5	6	8	5	2	3	3
Total	1,353	319	293	288	201	136	75	80	62	54	43	37	33	29	32	37	53	45	21	20	23
4 Emission Cost (CO2)																					
Retired Coal	617	289	226	177	0	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EOL Coal	4,604	899	923	930	793	498	272	297	216	204	161	146	132	118	135	161	230	200	115	114	130
Total	5,221	1,189	1,149	1,107	794	502	272	297	216	204	161	146	132	118	135	161	230	200	115	114	130
5 Proxy Generation Costs																					
Solar VOM	23	(4)	(2)	4	4	4	4	4	4	4	4	4	4	4	4	4	4	1	1	0	0
Wind VOM	(3,457)	(314)	(314)	(336)	(338)	(482)	(536)	(555)	(546)	(573)	(586)	(211)	(219)	(206)	(203)	(51)	14	14	15	15	15
Gas VOM	181	15	17	18	18	17	16	17	16	17	16	16	17	16	17	17	17	19	18	19	19
Battery VOM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LT Contract VOM	871	108	109	129	127	110	100	99	98	95	64	36	36	35	35	35	34	29	28	28	28
QFs VOM	2,054	275	266	252	233	231	228	210	208	194	190	189	174	148	145	143	112	31	23	9	6
Other VOM	(45)	1	1	1	1	1	1	1	(36)	(35)	(35)	(35)	(36)	(35)	15	15	15	25	37	38	39
Fuel	4,526	363	408	397	447	428	396	414	400	431	406	415	423	392	401	411	424	549	511	551	568
Start Fuel	78	8	5	5	6	8	8	8	10	8	8	8	9	7	7	8	7	7	6	7	7
Energy not Served	26	10	0	9	0	0	1	2	0	1	0	2	1	0	0	1	3	4	0	0	6
Dumped Energy	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Deficiency Cost	194	74	58	52	14	10	5	11	5	0	0	0	0	0	0	0	0	1	0	0	0
Emissions Costs	6,817	544	639	693	699	671	633	663	623	633	599	614	637	579	609	638	669	658	629	669	681
Total	11,268	1,081	1,186	1,223	1,212	997	857	872	783	774	667	1,038	1,046	940	1,030	1,220	1,300	1,338	1,269	1,335	1,370
VOM Integration, Wind + Solar																					
6 Proxy Generation Resource Fixed Costs																					
Generator Fixed / Build Costs	5,788	8	8	8	140	140	343	343	477	477	662	771	831	1,125	1,125	1,125	1,125	1,311	1,506	1,506	1,754
Battery Fixed / Build Costs	453	0	0	0	0	0	0	0	0	74	74	74	74	74	74	74	74	162	162	162	162
Solar FOM	1,762	0	0	0	92	129	154	157	168	169	211	234	239	293	299	303	310	349	350	355	374
Wind FOM	4,893	160	163	191	198	467	523	539	559	572	604	620	678	679	613	603	616	623	638	646	656
Gas FOM	438	36	38	38	40	41	42	43	46	49	52	54	55	33	34	34	35	36	37	37	37
Battery FOM	62	0	0	0	1	(1)	(1)	(2)	(0)	12	10	10	9	9	9	9	9	23	18	30	31
Other FOM	586	12	5	5	6	5	7	7	85	86	80	81	83	85	86	88	90	92	187	190	239
Use of Service	(6)	0	0	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(2)	(2)	(2)	(2)
Total	13,976	215	213	241	476	782	1,069	1,087	1,335	1,438	1,693	1,843	1,969	2,297	2,239	2,237	2,258	2,594	2,896	2,926	3,250
Remove Portfolio Credits																					
7 DSM Costs																					
DR VOM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DR FOM	610	0	6	19	29	34	38	42	46	51	55	60	63	86	90	105	117	138	157	166	230
EE VOM	1,085	9	21	30	40	50	60	74	88	103	121	138	153	167	181	195	205	221	240	260	276
EE FOM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	1,695	9	27	49	70	84	98	115	134	154	176	198	216	253	271	300	322	359	397	427	506
8 Market Costs																					
System Market Sales	(2,876)	(154)	(159)	(135)	(152)	(168)	(224)	(241)	(282)	(306)	(326)	(342)	(374)	(400)	(393)	(410)	(403)	(376)	(425)	(400)	(508)
System Market Purchases	5,197	428	486	497	500	488	476	478	463	479	455	460	453	437	466	479	539	569	564	590	631
Total	2,321	274	327	362	348	320	252	238	181	173	129	119	79	37	73	69	136	193	139	190	123
9 Transmission Costs																					
Transmission Build / Reinforcement Costs	1,341	0	0	0	1	99	151	151	157	157	159	177	199	214	214	214	214	256	256	256	296
Total	1,341	0	0	0	1	99	151	151	157	157	159	177	199	214	214	214	214	256	256	256	296

11 Total System Cost	40,019	3,371	3,518	3,588	3,475	3,204	3,154	3,092	3,122	3,145	3,272	3,760	3,891	4,096	4,291	4,454	4,735	5,193	5,327	5,366	5,815
Fixed	18,959	500	542	578	881	1,228	1,666	1,561	1,822	1,867	2,181	2,312	2,478	2,834	2,798	2,802	2,841	3,225	3,573	3,477	3,924
Variable	21,248	2,871	2,976	3,010	2,595	2,005	1,517	1,560	1,329	1,308	1,120	1,477	1,443	1,292	1,452	1,682	1,924	1,998	1,784	1,919	1,921
Adjustments	(187)	0	(0)	(0)	(0)	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(30)	(30)	41	(30)	(30)	(30)	(30)	(30)	(30)
12 Risk Adjusted PVRR	41,028		1009																		
Generation (GWH)																					
Retired Coal	7,757	3,289	2,548	1,892	3	25	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
EOL Coal	66,003	10,633	10,443	10,064	8,370	4,926	2,607	2,775	1,942	1,870	1,413	1,241	1,076	955	1,034	1,199	1,651	1,393	808	761	842
DSM	146,968	2,447	2,947	3,429	3,974	4,447	4,890	5,457	6,081	6,731	7,359	7,907	8,410	8,828	9,290	9,733	9,986	10,423	11,033	11,570	12,027
LT Contracts	32,375	1,445	1,689	2,601	3,063	2,434	2,264	2,229	2,213	2,149	1,656	1,204	1,185	1,172	1,160	1,145	1,132	925	914	904	891
QFs	73,171	5,736	5,611	5,384	5,067	5,024	4,970	4,719	4,682	4,460	4,410	4,384	4,172	3,667	3,371	3,330	2,627	655	552	256	94
Gas	263,280	14,480	16,206	16,716	16,913	15,285	14,219	14,468	13,582	13,632	12,897	12,747	12,744	11,402	11,559	11,686	11,854	11,332	10,414	10,667	10,475
Solar	205,470	1,223	1,271	1,467	5,583	6,694	8,267	8,237	8,560	8,755	10,089	11,245	11,220	14,292	14,273	14,252	14,227	16,400	16,397	16,372	16,644
Wind	363,528	9,370	9,388	9,842	10,153	15,894	18,300	18,297	18,380	18,345	20,173	20,181	21,713	21,610	21,630	21,641	21,751	21,662	21,661	21,661	21,875
Other System	113,015	4,397	4,600	4,214	3,921	3,819	3,595	3,565	6,102	6,112	5,758	5,725	5,761	5,768	5,719	5,719	5,722	6,080	8,538	8,573	9,326
Total	1,271,567	53,021	54,704	55,610	57,046	58,548	59,112	59,747	61,542	62,053	63,755	64,636	66,282	67,695	68,036	68,705	68,950	68,870	70,317	70,764	72,174

REDACTED
Docket No. UE 433
Exhibit PAC/902
Witness: Thomas R. Burns

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Exhibit Accompanying Direct Testimony of Thomas R. Burns

Rock Creek I Analysis

February 2024

REDACTED

Estimated Annual Revenue Requirement Results ($ million)

Medium Gas, Medium CO2

(Benefit) /Cost	*PVRR(d)*	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Cost of Project	$611	$0	$0	$0	$0	$73	$67	$70	$70	$67	$66	$66	$68	$70	$71	$104	$128	$130	$133	$135	$138
[redacted]																					
Change in NPC	($171)	$0	$0	$0	$0	($27)	($38)	($39)	($31)	($18)	($18)	($22)	($22)	$122	($34)	($34)	($32)	($38)	($42)	($51)	($71)
Change in Emissions	($75)	$0	$0	$0	$0	($11)	($17)	($20)	($10)	($6)	($8)	($8)	($9)	$39	($15)	($16)	($22)	($14)	($16)	($18)	($16)
Change in VOM & Driver Adjustments	$8	$0	$0	$0	$0	$0	$0	($0)	($1)	($1)	($1)	($1)	($1)	$37	($1)	($1)	($2)	($2)	($3)	($3)	($5)
Change in DSM	($20)	$0	$0	($0)	($0)	($0)	($0)	($1)	($2)	($2)	($2)	($2)	($1)	($1)	($4)	($6)	($6)	($6)	($7)	($7)	($7)
Change in Deficiency	$5	$0	$0	$0	($0)	($4)	($0)	($0)	($2)	$1	$0	$0	$2	$15	$0	($0)	$0	$0	$0	$0	$5
Change in System Fixed Cost	($502)	$0	$0	$0	$0	$0	$0	$0	($28)	($63)	($63)	($63)	($64)	($407)	($38)	($38)	($94)	($108)	($108)	($109)	($109)
Net (Benefit) /Cost	($143)	$0	$0	$0	$0	$32	$11	$9	($5)	($22)	($26)	($30)	($27)	($125)	($21)	$7	($28)	($39)	($43)	($52)	($64)
Risk Adjustment	($20)																				
Net (Benefit) /Cost with Risk Adjustment	($163)																				

Medium Gas, No CO2

(Benefit) /Cost	*PVRR(d)*	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Cost of Project	$615	$0	$0	$0	$0	$75	$68	$72	$70	$67	$66	$66	$68	$70	$71	$104	$127	$130	$132	$135	$138
[redacted]																					
Change in NPC	($104)	$0	($0)	$0	($0)	($35)	($29)	($28)	($26)	$18	$15	$12	($16)	($56)	$1	$3	($0)	($321)	$82	$89	$125
Change in Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in VOM & Driver Adjustments	$44	$0	$0	($0)	($0)	$0	$10	$9	$9	$10	$10	$10	$10	$9	$10	$10	($1)	$8	($11)	($11)	($8)
Change in DSM	($19)	$0	$0	($0)	($0)	($1)	($1)	($1)	($2)	($3)	($4)	($4)	($3)	($3)	($3)	($3)	($3)	($3)	($3)	($3)	($3)
Change in Deficiency	($1)	$0	$0	$0	$0	($3)	($0)	($0)	$1	$28	$10	$8	$3	($41)	$0	$0	$1	($22)	$0	$0	$2
Change in System Fixed Cost	($568)	$0	$0	$0	$0	$0	($29)	($30)	($34)	($176)	($177)	($178)	($72)	$76	($151)	($152)	($153)	$406	($233)	($234)	($237)
Net (Benefit) /Cost	($33)	$0	($0)	$0	($0)	$35	$18	$22	$18	($56)	($79)	($85)	($11)	$54	($71)	($38)	($28)	$197	($33)	($25)	$17
Risk Adjustment	($18)																				
Net (Benefit) /Cost with Risk Adjustment	($51)																				

Low Gas, No CO2

(Benefit) /Cost	*PVRR(d)*	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Cost of Project	$613	$0	$0	$0	$0	$74	$67	$71	$70	$67	$66	$66	$68	$70	$71	$104	$128	$130	$133	$135	$138
[redacted]																					
Change in NPC	($65)	$0	$0	$0	($0)	($19)	($28)	($31)	($2)	($2)	($3)	($3)	($2)	($3)	($3)	($3)	($3)	($1)	$2	($4)	($2)
Change in Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in VOM & Driver Adjustments	($8)	$0	$0	$0	$0	$0	$0	($0)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($2)	($1)	($2)	($2)
Change in DSM	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in Deficiency	($6)	$0	$0	$0	$0	($7)	($0)	($1)	($0)	$0	($0)	$0	$0	$0	$0	$0	$0	$0	$0	($0)	$1
Change in System Fixed Cost	($519)	$0	$0	$0	$0	$0	$0	$0	($96)	($96)	($97)	($97)	($98)	($98)	($99)	($99)	($99)	($100)	($100)	($101)	($101)
Net (Benefit) /Cost	$16	$0	$0	$0	($0)	$48	$39	$38	($30)	($33)	($35)	($36)	($33)	($32)	($32)	$1	$24	$28	$32	$28	$34
Risk Adjustment	($14)																				
Net (Benefit) /Cost with Risk Adjustment	$2																				

Docket No. UE 433
Exhibit PAC/903
Witness: Thomas R. Burns

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Thomas R. Burns

Rock River I Analysis

February 2024

Table 7 Rock River 1 110%PTC

	PVRR(d) Net (Benefit)/Cost ($million)	**Nom. Lev. Net Benefit ($/MWh of Incremental Energy)**
High Natural Gas, High CO_2	($91.69)	($43/MWh)
Medium Natural Gas, Medium CO_2	($54.09)	($25/MWh)
Low Natural Gas, No CO_2	($15.12)	($7/MWh)
Medium Natural Gas, SCGHG	($167.35)	($78/MWh)

Table 1 Rock River 1 60%PTC

	PVRR(d) Net (Benefit)/Cost ($million)	**Nom. Lev. Net Benefit ($/MWh of Incremental Energy)**
High Natural Gas, High CO_2	($67.76)	($31/MWh)
Medium Natural Gas, Medium CO_2	($30.15)	($14/MWh)
Low Natural Gas, No CO_2	$23.12	$11/MWh
Medium Natural Gas, SCGHG	($143.42)	($67/MWh)

Table 1 Rock River 1 110% vs 60%PTC

	PVRR(d) Net (Benefit)/Cost ($million)	**Nom. Lev. Net Benefit ($/MWh of Incremental Energy)**
High Natural Gas, High CO2	($23.94)	($11/MWh)
Medium Natural Gas, Medium CO2	($23.94)	($11/MWh)
Low Natural Gas, No CO2	($38.24)	($18/MWh)
Medium Natural Gas, SCGHG	($23.94)	($11/MWh)

Nominal Discount Rate	6.88%	
Inflation Rate	2.155%	
Real Discount Rate	4.63%	
Project Size (MW)	53.58	45.5%

Line No.	Rock River I	Formula	PVRR(d)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054
(1)	**Generation (GWh)**		2,153	50	213	213	213	214	213	213	213	214	213	213	213	214	213	213	213	214	213	213	213	214	213	213	213	214	213	213	213	214	201	123
	Project Costs																																	
	Capital Rev. Req.		$85.7	$2.1	$11.1	$10.4	$9.9	$9.5	$9.2	$8.9	$8.8	$8.6	$8.4	$8.2	$8.1	$8.0	$7.9	$7.8	$7.7	$7.6	$7.5	$7.5	$7.4	$7.3	$7.3	$7.2	$7.2	$7.2	$7.2	$7.3	$7.5	$7.7	$7.7	($12.0)
	PTCs		($52.7)	($2.0)	($8.7)	($8.7)	($9.0)	($9.1)	($9.3)	($9.3)	($9.6)	($10.0)	($10.0)	($7.9)	$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	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
	O&M		$13.6	$0.3	$1.4	$1.4	$1.5	$1.6	$1.2	$1.2	$1.0	$1.0	$1.0	$1.0	$1.3	$1.3	$1.3	$1.3	$1.4	$1.4	$1.4	$1.4	$1.5	$1.5	$1.5	$1.6	$1.6	$1.6	$1.7	$1.7	$1.7	$1.8	$1.8	$1.2
	Gen Tax		$1.7	$0.0	$0.0	$0.0	$0.0	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.1
	Property Tax		$3.8	$0.0	$0.6	$0.6	$0.5	$0.5	$0.5	$0.4	$0.4	$0.4	$0.4	$0.4	$0.4	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2	$0.1	$0.1	$0.1	$0.1	$0.0	($0.0)
	Transmission Upgrades		$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	$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	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
(2)	**Project Costs ($ million)**		$52.1	$0.4	$4.3	$3.7	$3.0	$2.7	$1.7	$1.5	$0.7	$0.3	$0.0	$2.0	$10.0	$9.9	$9.8	$9.7	$9.6	$9.5	$9.4	$9.4	$9.3	$9.3	$9.2	$9.2	$9.2	$9.2	$9.2	$9.3	$9.5	$9.7	$9.7	($10.7)
(3)	**Project Cost ($/MWh)**	(2) / (1)	$24.19	$8.58	$20.36	$17.14	$13.96	$12.74	$8.15	$6.88	$3.47	$1.20	$0.10	$9.15	$46.76	$46.17	$45.84	$45.45	$45.08	$44.39	$44.21	$43.89	$43.61	$43.21	$43.18	$43.04	$42.99	$42.88	$43.24	$43.70	$44.59	$45.43	$48.50	($87.13)

Line No.	Medium Natural Gas, Medium CO_2	Formula	PVRR	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054
(4)	System (Benefit)/Cost (2024-2040)			($29.20)	($29.20)	($26.75)	($30.97)	($35.62)	($35.65)	($39.72)	($36.37)	($41.40)	($39.58)	($43.38)	($48.97)	($47.20)	($61.26)	($58.27)	($68.92)	($71.94)														
(5)	Real Lev. 2032-2040											($47.76)	($48.79)	($49.85)	($50.92)	($52.02)	($53.14)	($54.28)	($55.45)	($56.65)	($57.87)	($59.12)	($60.39)	($61.69)	($63.02)	($64.38)	($65.77)	($67.18)	($68.63)	($70.11)	($71.62)	($73.16)	($74.74)	($76.35)
(6)	Real Lev. 2038-2040																	($64.73)	($66.13)	($67.55)	($69.01)	($70.49)	($72.01)	($73.56)	($75.15)	($76.77)	($78.42)	($80.11)	($81.84)	($83.60)	($85.40)	($87.25)	($89.13)	($91.05)
(7)	System (Benefit)/Cost w/ '32-'40 Extrap.		($46.39)	($29.20)	($29.20)	($26.75)	($30.97)	($35.62)	($35.65)	($39.72)	($36.37)	($41.40)	($39.58)	($43.38)	($48.97)	($47.20)	($61.26)	($58.27)	($68.92)	($71.94)	($57.87)	($59.12)	($60.39)	($61.69)	($63.02)	($64.38)	($65.77)	($67.18)	($68.63)	($70.11)	($71.62)	($73.16)	($74.74)	($76.35)
(8)	System (Benefit)/Cost w/ '38-'40 Extrap.		($49.31)	($29.20)	($29.20)	($26.75)	($30.97)	($35.62)	($35.65)	($39.72)	($36.37)	($41.40)	($39.58)	($43.38)	($48.97)	($47.20)	($61.26)	($58.27)	($68.92)	($71.94)	($69.01)	($70.49)	($72.01)	($73.56)	($75.15)	($76.77)	($78.42)	($80.11)	($81.84)	($83.60)	($85.40)	($87.25)	($89.13)	($91.05)
	System (Benefit)/Cost ($ million)																																	
(9)	MM '32-'40 Extrap.	(1) X (7)	($99.9)	($1.5)	($6.2)	($5.7)	($6.6)	($7.6)	($7.6)	($8.5)	($7.8)	($8.9)	($8.4)	($9.3)	($10.4)	($10.1)	($13.1)	($12.4)	($14.7)	($15.4)	($12.3)	($12.6)	($12.9)	($13.2)	($13.4)	($13.7)	($14.0)	($14.4)	($14.6)	($15.0)	($15.3)	($15.7)	($15.0)	($9.4)
(10)	MM '38-'40 Extrap.	(1) X (8)	($106.2)	($1.5)	($6.2)	($5.7)	($6.6)	($7.6)	($7.6)	($8.5)	($7.8)	($8.9)	($8.4)	($9.3)	($10.4)	($10.1)	($13.1)	($12.4)	($14.7)	($15.4)	($14.7)	($15.0)	($15.4)	($15.8)	($16.0)	($16.4)	($16.7)	($17.2)	($17.5)	($17.8)	($18.2)	($18.7)	($17.9)	($11.2)
	Net (Benefit)/Cost ($ million)																																	
(11)	MM '32-'40 Extrap.	(2) + (9)	**($47.8)**	($1.0)	($1.9)	($2.1)	($3.6)	($4.9)	($5.9)	($7.0)	($7.0)	($8.6)	($8.4)	($7.3)	($0.5)	($0.2)	($3.3)	($2.7)	($5.1)	($5.9)	($2.9)	($3.2)	($3.6)	($4.0)	($4.2)	($4.6)	($4.9)	($5.2)	($5.4)	($5.6)	($5.8)	($5.9)	($5.3)	($20.1)
(12)	MM '38-'40 Extrap.	(2) + (10)	**($54.1)**	($1.0)	($1.9)	($2.1)	($3.6)	($4.9)	($5.9)	($7.0)	($7.0)	($8.6)	($8.4)	($7.3)	($0.5)	($0.2)	($3.3)	($2.7)	($5.1)	($5.9)	($5.3)	($5.7)	($6.1)	($6.5)	($6.8)	($7.2)	($7.6)	($8.0)	($8.2)	($8.5)	($8.7)	($9.0)	($8.2)	($21.9)
	Net (Benefit)/Cost ($/MWh)																																	
(13)	MM '32-'40 Extrap.	(11) / (1)	**($22.21)**	($20.62)	($8.84)	($9.62)	($17.01)	($22.88)	($27.50)	($32.83)	($32.91)	($40.20)	($39.48)	($34.23)	($2.21)	($1.03)	($15.42)	($12.82)	($23.85)	($27.55)	($13.66)	($15.22)	($16.78)	($18.48)	($19.84)	($21.34)	($22.78)	($24.30)	($25.39)	($26.41)	($27.03)	($27.74)	($26.24)	($163.48)
(14)	MM '38-'40 Extrap.	(12) / (1)	**($25.12)**	($20.62)	($8.84)	($9.62)	($17.01)	($22.88)	($27.50)	($32.83)	($32.91)	($40.20)	($39.48)	($34.23)	($2.21)	($1.03)	($15.42)	($12.82)	($23.85)	($27.55)	($24.80)	($26.60)	($28.40)	($30.35)	($31.97)	($33.73)	($35.43)	($37.23)	($38.60)	($39.90)	($40.81)	($41.82)	($40.63)	($178.18)

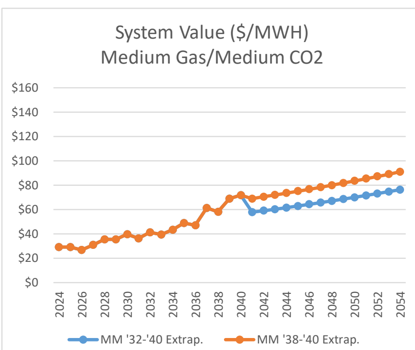
Line No.	Low Natural Gas, No CO_2	Formula	PVRR	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054
(15)	System (Benefit)/Cost (2024-2040)			($19.20)	($22.93)	($18.71)	($21.47)	($28.93)	($23.49)	($22.49)	($21.91)	($25.13)	($27.92)	($28.05)	($29.11)	($42.62)	($36.33)	($36.22)	($37.15)	($42.30)														
(16)	Real Lev. 2032-2040											($30.52)	($31.18)	($31.85)	($32.54)	($33.24)	($33.96)	($34.69)	($35.44)	($36.20)	($36.98)	($37.78)	($38.59)	($39.42)	($40.27)	($41.14)	($42.03)	($42.93)	($43.86)	($44.80)	($45.77)	($46.75)	($47.76)	($48.79)
(17)	Real Lev. 2038-2040																	($37.64)	($38.45)	($39.28)	($40.13)	($40.99)	($41.88)	($42.78)	($43.70)	($44.64)	($45.60)	($46.59)	($47.59)	($48.62)	($49.66)	($50.73)	($51.83)	($52.94)
(18)	System (Benefit)/Cost w/ '32-'40 Extrap.		($30.39)	($19.20)	($22.93)	($18.71)	($21.47)	($28.93)	($23.49)	($22.49)	($21.91)	($25.13)	($27.92)	($28.05)	($29.11)	($42.62)	($36.33)	($36.22)	($37.15)	($42.30)	($36.98)	($37.78)	($38.59)	($39.42)	($40.27)	($41.14)	($42.03)	($42.93)	($43.86)	($44.80)	($45.77)	($46.75)	($47.76)	($48.79)
(19)	System (Benefit)/Cost w/ '38-'40 Extrap.		($31.21)	($19.20)	($22.93)	($18.71)	($21.47)	($28.93)	($23.49)	($22.49)	($21.91)	($25.13)	($27.92)	($28.05)	($29.11)	($42.62)	($36.33)	($36.22)	($37.15)	($42.30)	($40.13)	($40.99)	($41.88)	($42.78)	($43.70)	($44.64)	($45.60)	($46.59)	($47.59)	($48.62)	($49.66)	($50.73)	($51.83)	($52.94)
	System (Benefit)/Cost ($ million)																																	
(20)	LN '32-'40 Extrap.	(1) X (18)	($65.4)	($1.0)	($4.9)	($4.0)	($4.6)	($6.2)	($5.0)	($4.8)	($4.7)	($5.4)	($6.0)	($6.0)	($6.2)	($9.1)	($7.8)	($7.7)	($7.9)	($9.1)	($7.9)	($8.1)	($8.2)	($8.4)	($8.6)	($8.8)	($9.0)	($9.2)	($9.4)	($9.6)	($9.8)	($10.0)	($9.6)	($6.0)
(21)	LN '38-'40 Extrap.	(1) X (19)	($67.2)	($1.0)	($4.9)	($4.0)	($4.6)	($6.2)	($5.0)	($4.8)	($4.7)	($5.4)	($6.0)	($6.0)	($6.2)	($9.1)	($7.8)	($7.7)	($7.9)	($9.1)	($8.6)	($8.7)	($8.9)	($9.2)	($9.3)	($9.5)	($9.7)	($10.0)	($10.2)	($10.4)	($10.6)	($10.9)	($10.4)	($6.5)
	Net (Benefit)/Cost ($ million)																																	
(22)	LN '32-'40 Extrap.	(2) + (20)	**($13.3)**	($0.5)	($0.5)	($0.3)	($1.6)	($3.5)	($3.3)	($3.3)	($3.9)	($5.1)	($5.9)	($4.0)	$3.8	$0.8	$2.0	$2.0	$1.7	$0.4	$1.5	$1.3	$1.1	$0.8	$0.6	$0.4	$0.2	($0.0)	($0.1)	($0.2)	($0.3)	($0.3)	$0.1	($16.7)
(23)	LN '38-'40 Extrap.	(2) + (21)	**($15.1)**	($0.5)	($0.5)	($0.3)	($1.6)	($3.5)	($3.3)	($3.3)	($3.9)	($5.1)	($5.9)	($4.0)	$3.8	$0.8	$2.0	$2.0	$1.7	$0.4	$0.9	$0.6	$0.4	$0.1	($0.1)	($0.3)	($0.6)	($0.8)	($0.9)	($1.0)	($1.1)	($1.1)	($0.7)	($17.2)
	Net (Benefit)/Cost ($/MWh)																																	
(24)	LN '32-'40 Extrap.	(22) / (1)	**($6.20)**	($10.62)	($2.57)	($1.57)	($7.51)	($16.19)	($15.35)	($15.61)	($18.45)	($23.93)	($27.83)	($18.90)	$17.65	$3.55	$9.51	$9.24	$7.93	$2.09	$7.23	$6.12	$5.02	$3.79	$2.90	$1.90	$0.96	($0.05)	($0.61)	($1.10)	($1.18)	($1.33)	$0.74	($135.92)
(25)	LN '38-'40 Extrap.	(23) / (1)	**($7.02)**	($10.62)	($2.57)	($1.57)	($7.51)	($16.19)	($15.35)	($15.61)	($18.45)	($23.93)	($27.83)	($18.90)	$17.65	$3.55	$9.51	$9.24	$7.93	$2.09	$4.08	$2.90	$1.74	$0.43	($0.52)	($1.60)	($2.61)	($3.71)	($4.35)	($4.91)	($5.07)	($5.31)	($3.33)	($140.07)

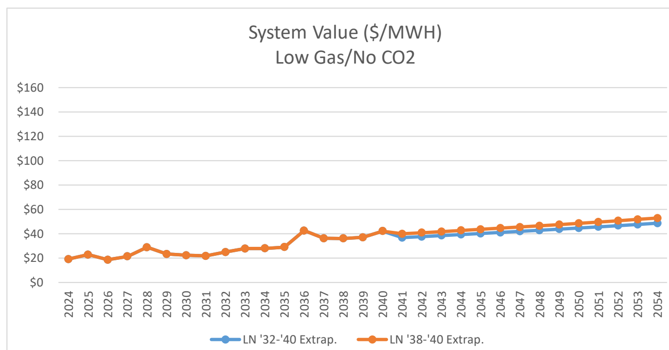
Line No.	High Natural Gas, High CO_2	Formula	PVRR	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054
(26)	System (Benefit)/Cost (2024-2040)			($41.80)	($41.80)	($41.07)	($44.47)	($47.08)	($49.91)	($54.85)	($55.47)	($70.40)	($64.43)	($68.56)	($79.20)	($80.43)	($89.26)	($88.91)	($40.67)	($107.64)														
(27)	Real Lev. 2032-2040											($70.03)	($71.54)	($73.08)	($74.66)	($76.27)	($77.91)	($79.59)	($81.30)	($83.05)	($84.84)	($86.67)	($88.54)	($90.45)	($92.40)	($94.39)	($96.42)	($98.50)	($100.62)	($102.79)	($105.01)	($107.27)	($109.58)	($111.94)
(28)	Real Lev. 2038-2040																	($77.09)	($78.75)	($80.44)	($82.18)	($83.95)	($85.76)	($87.61)	($89.49)	($91.42)	($93.39)	($95.41)	($97.46)	($99.56)	($101.71)	($103.90)	($106.14)	($108.43)
(29)	System (Benefit)/Cost w/ '32-'40 Extrap.		($67.48)	($41.80)	($41.80)	($41.07)	($44.47)	($47.08)	($49.91)	($54.85)	($55.47)	($70.40)	($64.43)	($68.56)	($79.20)	($80.43)	($89.26)	($88.91)	($40.67)	($107.64)	($84.84)	($86.67)	($88.54)	($90.45)	($92.40)	($94.39)	($96.42)	($98.50)	($100.62)	($102.79)	($105.01)	($107.27)	($109.58)	($111.94)
(30)	System (Benefit)/Cost w/ '38-'40 Extrap.		($66.78)	($41.80)	($41.80)	($41.07)	($44.47)	($47.08)	($49.91)	($54.85)	($55.47)	($70.40)	($64.43)	($68.56)	($79.20)	($80.43)	($89.26)	($88.91)	($40.67)	($107.64)	($82.18)	($83.95)	($85.76)	($87.61)	($89.49)	($91.42)	($93.39)	($95.41)	($97.46)	($99.56)	($101.71)	($103.90)	($106.14)	($108.43)
	System (Benefit)/Cost ($ million)																																	
(31)	HH '32-'40 Extrap.	(1) X (29)	($145.3)	($2.1)	($8.9)	($8.8)	($9.5)	($10.1)	($10.6)	($11.7)	($11.8)	($15.1)	($13.7)	($14.6)	($16.9)	($17.2)	($19.0)	($19.0)	($8.7)	($23.0)	($18.1)	($18.5)	($18.9)	($19.4)	($19.7)	($20.1)	($20.6)	($21.1)	($21.5)	($21.9)	($22.4)	($23.0)	($22.0)	($13.7)
(32)	HH '38-'40 Extrap.	(1) X (30)	($143.8)	($2.1)	($8.9)	($8.8)	($9.5)	($10.1)	($10.6)	($11.7)	($11.8)	($15.1)	($13.7)	($14.6)	($16.9)	($17.2)	($19.0)	($19.0)	($8.7)	($23.0)	($17.5)	($17.9)	($18.3)	($18.8)	($19.1)	($19.5)	($19.9)	($20.4)	($20.8)	($21.2)	($21.7)	($22.2)	($21.3)	($13.3)
	Net (Benefit)/Cost ($ million)																																	
(33)	HH '32-'40 Extrap.	(2) + (31)	**($93.2)**	($1.7)	($4.6)	($5.1)	($6.5)	($7.4)	($8.9)	($10.2)	($11.1)	($14.8)	($13.7)	($12.7)	($6.9)	($7.3)	($9.3)	($9.3)	$0.9	($13.5)	($8.7)	($9.1)	($9.6)	($10.1)	($10.5)	($11.0)	($11.4)	($11.9)	($12.2)	($12.6)	($12.9)	($13.2)	($12.3)	($24.4)
(34)	HH '38-'40 Extrap.	(2) + (32)	**($91.7)**	($1.7)	($4.6)	($5.1)	($6.5)	($7.4)	($8.9)	($10.2)	($11.1)	($14.8)	($13.7)	($12.7)	($6.9)	($7.3)	($9.3)	($9.3)	$0.9	($13.5)	($8.1)	($8.5)	($9.0)	($9.5)	($9.9)	($10.3)	($10.8)	($11.2)	($11.6)	($11.9)	($12.2)	($12.5)	($11.6)	($24.0)
	Net (Benefit)/Cost ($/MWh)																																	
(35)	HH '32-'40 Extrap.	(33) / (1)	**($43.29)**	($33.22)	($21.43)	($23.93)	($30.51)	($34.33)	($41.76)	($47.96)	($52.01)	($69.21)	($64.34)	($59.41)	($32.45)	($34.26)	($43.42)	($43.45)	$4.41	($63.25)	($40.64)	($42.78)	($44.93)	($47.24)	($49.22)	($51.35)	($53.43)	($55.62)	($57.38)	($59.09)	($60.42)	($61.84)	($61.08)	($199.07)
(36)	HH '38-'40 Extrap.	(34) / (1)	**($42.59)**	($33.22)	($21.43)	($23.93)	($30.51)	($34.33)	($41.76)	($47.96)	($52.01)	($69.21)	($64.34)	($59.41)	($32.45)	($34.26)	($43.42)	($43.45)	$4.41	($63.25)	($37.97)	($40.06)	($42.14)	($44.39)	($46.32)	($48.38)	($50.40)	($52.53)	($54.22)	($55.86)	($57.12)	($58.47)	($57.64)	($195.56)

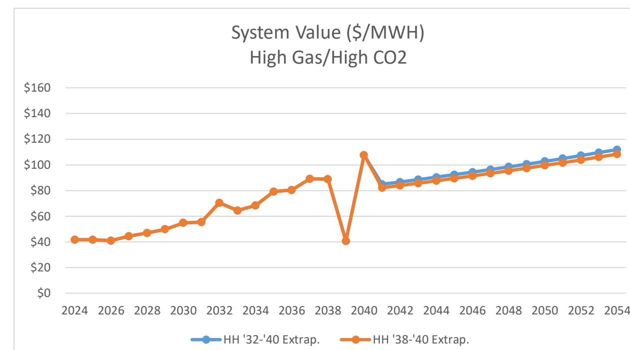
Line No.	Medium Natural Gas, SCGHG	Formula	PVRR	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054
(37)	System (Benefit)/Cost (2024-2040)			($90.80)	($90.80)	($95.25)	($101.03)	($81.04)	($88.52)	($100.64)	($94.48)	($91.92)	($89.39)	($92.67)	($94.66)	($102.02)	($108.84)	($108.30)	($101.83)	($106.34)														
(38)	Real Lev. 2032-2040											($91.17)	($93.13)	($95.14)	($97.19)	($99.29)	($101.43)	($103.61)	($105.84)	($108.12)	($110.45)	($112.84)	($115.27)	($117.75)	($120.29)	($122.88)	($125.53)	($128.23)	($131.00)	($133.82)	($136.70)	($139.65)	($142.66)	($145.73)
(39)	Real Lev. 2038-2040																	($103.39)	($105.62)	($107.90)	($110.22)	($112.60)	($115.02)	($117.50)	($120.03)	($122.62)	($125.26)	($127.96)	($130.72)	($133.54)	($136.41)	($139.35)	($142.36)	($145.42)
(40)	System (Benefit)/Cost w/ '32-'40 Extrap.		($101.99)	($90.80)	($90.80)	($95.25)	($101.03)	($81.04)	($88.52)	($100.64)	($94.48)	($91.92)	($89.39)	($92.67)	($94.66)	($102.02)	($108.84)	($108.30)	($101.83)	($106.34)	($110.45)	($112.84)	($115.27)	($117.75)	($120.29)	($122.88)	($125.53)	($128.23)	($131.00)	($133.82)	($136.70)	($139.65)	($142.66)	($145.73)
(41)	System (Benefit)/Cost w/ '38-'40 Extrap.		($101.93)	($90.80)	($90.80)	($95.25)	($101.03)	($81.04)	($88.52)	($100.64)	($94.48)	($91.92)	($89.39)	($92.67)	($94.66)	($102.02)	($108.84)	($108.30)	($101.83)	($106.34)	($110.22)	($112.60)	($115.02)	($117.50)	($120.03)	($122.62)	($125.26)	($127.96)	($130.72)	($133.54)	($136.41)	($139.35)	($142.36)	($145.42)

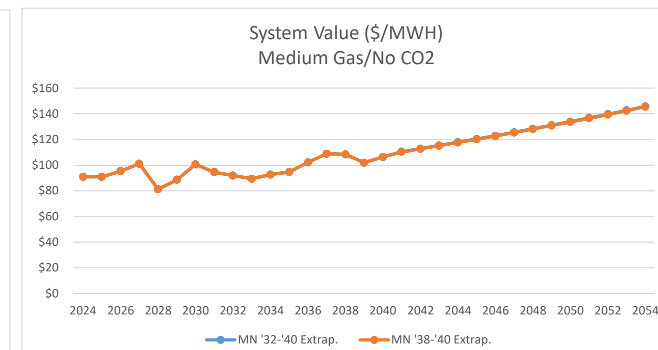
System (Benefit)/Cost ($ million)																																		
(42)	MN '32-'40 Extrap.	(1) X (40)	($219.6)	($4.5)	($19.4)	($20.3)	($21.6)	($17.4)	($18.9)	($21.5)	($20.2)	($19.7)	($19.1)	($19.8)	($20.2)	($21.8)	($23.2)	($23.1)	($21.7)	($22.8)	($23.6)	($24.1)	($24.6)	($25.2)	($25.7)	($26.2)	($26.8)	($27.5)	($27.9)	($28.5)	($29.2)	($29.9)	($28.7)	($17.9)
(43)	MN '38-'40 Extrap.	(1) X (41)	($219.4)	($4.5)	($19.4)	($20.3)	($21.6)	($17.4)	($18.9)	($21.5)	($20.2)	($19.7)	($19.1)	($19.8)	($20.2)	($21.8)	($23.2)	($23.1)	($21.7)	($22.8)	($23.5)	($24.0)	($24.5)	($25.2)	($25.6)	($26.2)	($26.7)	($27.4)	($27.9)	($28.5)	($29.1)	($29.8)	($28.6)	($17.8)
Net (Benefit)/Cost ($ million)																																		
(44)	MN '32-'40 Extrap.	(2) + (42)	**($167.5)**	($4.1)	($15.0)	($16.7)	($18.6)	($14.6)	($17.1)	($20.0)	($19.4)	($19.4)	($19.0)	($17.8)	($10.2)	($12.0)	($13.4)	($13.4)	($12.1)	($13.3)	($14.1)	($14.7)	($15.3)	($16.0)	($16.5)	($17.0)	($17.6)	($18.3)	($18.7)	($19.2)	($19.7)	($20.2)	($18.9)	($28.6)
(45)	MN '38-'40 Extrap.	(2) + (43)	**($167.4)**	($4.1)	($15.0)	($16.7)	($18.6)	($14.6)	($17.1)	($20.0)	($19.4)	($19.4)	($19.0)	($17.8)	($10.2)	($12.0)	($13.4)	($13.4)	($12.1)	($13.3)	($14.1)	($14.7)	($15.2)	($15.9)	($16.4)	($17.0)	($17.6)	($18.2)	($18.7)	($19.2)	($19.6)	($20.1)	($18.9)	($28.5)
Net (Benefit)/Cost ($/MWh)																																		
(46)	MN '32-'40 Extrap.	(44) / (1)	**($77.80)**	($82.23)	($70.44)	($78.11)	($87.07)	($68.30)	($80.38)	($93.76)	($91.01)	($90.72)	($89.29)	($83.53)	($47.91)	($55.85)	($63.00)	($62.85)	($56.75)	($61.95)	($66.25)	($68.94)	($71.65)	($74.54)	($77.11)	($79.84)	($82.54)	($85.36)	($87.75)	($90.12)	($92.11)	($94.22)	($94.16)	($232.86)
(47)	MN '38-'40 Extrap.	(45) / (1)	**($77.74)**	($82.23)	($70.44)	($78.11)	($87.07)	($68.30)	($80.38)	($93.76)	($91.01)	($90.72)	($89.29)	($83.53)	($47.91)	($55.85)	($63.00)	($62.85)	($56.75)	($61.95)	($66.02)	($68.70)	($71.41)	($74.29)	($76.86)	($79.58)	($82.27)	($85.08)	($87.48)	($89.83)	($91.82)	($93.93)	($93.86)	($232.55)

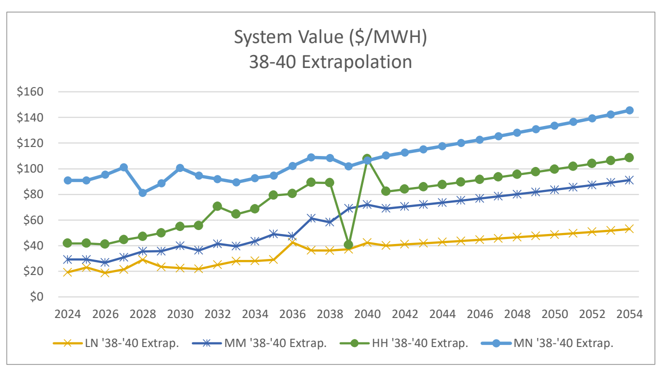
2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054
$29.20	$29.20	$26.75	$30.97	$35.62	$35.65	$39.72	$36.37	$41.40	$39.58	$43.38	$48.97	$47.20	$61.26	$58.27	$68.92	$71.94	$57.87	$59.12	$60.39	$61.69	$63.02	$64.38	$65.77	$67.18	$68.63	$70.11	$71.62	$73.16	$74.74	$76.35
$29.20	$29.20	$26.75	$30.97	$35.62	$35.65	$39.72	$36.37	$41.40	$39.58	$43.38	$48.97	$47.20	$61.26	$58.27	$68.92	$71.94	$69.01	$70.49	$72.01	$73.56	$75.15	$76.77	$78.42	$80.11	$81.84	$83.60	$85.40	$87.25	$89.13	$91.05
$19.20	$22.93	$18.71	$21.47	$28.93	$23.49	$22.49	$21.91	$25.13	$27.92	$28.05	$29.11	$42.62	$36.33	$36.22	$37.15	$42.30	$36.98	$37.78	$38.59	$39.42	$40.27	$41.14	$42.03	$42.93	$43.86	$44.80	$45.77	$46.75	$47.76	$48.79
$19.20	$22.93	$18.71	$21.47	$28.93	$23.49	$22.49	$21.91	$25.13	$27.92	$28.05	$29.11	$42.62	$36.33	$36.22	$37.15	$42.30	$40.13	$40.99	$41.88	$42.78	$43.70	$44.64	$45.60	$46.59	$47.59	$48.62	$49.66	$50.73	$51.83	$52.94
$41.80	$41.80	$41.07	$44.47	$47.08	$49.91	$54.85	$55.47	$70.40	$64.43	$68.56	$79.20	$80.43	$89.26	$88.91	$40.67	$107.64	$84.84	$86.67	$88.54	$90.45	$92.40	$94.39	$96.42	$98.50	$100.62	$102.79	$105.01	$107.27	$109.58	$111.94
$41.80	$41.80	$41.07	$44.47	$47.08	$49.91	$54.85	$55.47	$70.40	$64.43	$68.56	$79.20	$80.43	$89.26	$88.91	$40.67	$107.64	$82.18	$83.95	$85.76	$87.61	$89.49	$91.42	$93.39	$95.41	$97.46	$99.56	$101.71	$103.90	$106.14	$108.43
$90.80	$90.80	$95.25	$101.03	$81.04	$88.52	$100.64	$94.48	$91.92	$89.39	$92.67	$94.66	$102.02	$108.84	$108.30	$101.83	$106.34	$110.45	$112.84	$115.27	$117.75	$120.29	$122.88	$125.53	$128.23	$131.00	$133.82	$136.70	$139.65	$142.66	$145.73
$90.80	$90.80	$95.25	$101.03	$81.04	$88.52	$100.64	$94.48	$91.92	$89.39	$92.67	$94.66	$102.02	$108.84	$108.30	$101.83	$106.34	$110.22	$112.60	$115.02	$117.50	$120.03	$122.62	$125.26	$127.96	$130.72	$133.54	$136.41	$139.35	$142.36	$145.42











Project Summary

Project Name	Structure	Capacity (AC)	Start Date	End Date	Term/Life (years)	Curve	NDC (unadj)	NDC (avg CC)	NDC (ann CC)	Avg Cap Contrib	NB/C (unadj)	NB/C (avg CC)	NB/C (ann CC)
Rock River I	BTA	53.6	11/1/2024	10/31/2054	30	Wyoming East	($6.81)	($47.11)	($46.38)	14.5%	($6.81)	($47.11)	($46.38)

Rock River I Asset Purchase Summary - 60% PTC

	Value of Generation	Value of RECs (1)	Value of Storage	Market Value of PTC (2)	Capital Revenue Requirement (3) w/o TV	RRCap Revenue Requirement (3)	Cost of O&M (Storage)	Cost of O&M (Generation)	Cost of Property Taxes	Cost of Generation Tax	Cost of Integration	Cost of Wheeling (4)	Direct Assigned Rev Req w/o TV	Network Upgrade Rev Req w/o TV	CapEx Terminal Value	DA Terminal Value	NU Terminal Value	Net Delivery Cost	Net Benefit/(Cost)	Embedded Terminal Value
Nom. Lev ($/MWh)	$0.00	$0.00	$0.00	$24.46	($36.22)	($4.36)	$0.00	($5.13)	($1.77)	($0.79)	($1.16)	$0.00	$0.00	$0.00	$0.79	$0.00	$0.00	($24.19)	($24.19)	$0.79
Present Value ($)	$0	$0	$0	$52,661,029	($77,980,842)	($9,389,085)	$0	($11,051,152)	($3,807,203)	($1,701,156)	($2,507,821)	$0	$0	$0	$1,701,515	$0	$0	($52,074,716)	($52,074,716)	$1,701,515
PV ($/kw-mo)	$0.00	$0.00	$0.00	$6.89	($10.20)	($1.23)	$0.00	($1.45)	($0.50)	($0.22)	($0.33)	$0.00	$0.00	$0.00	$0.22	$0.00	$0.00	($6.81)	($6.81)	$0.22

Rock River I Asset Purchase Annual Cost Detail

Year	Value of Generation	Value of RECs (1)	Value of Storage	Market Value of PTC (2)	Capital Revenue Requirement (3) w/o TV	RRCap Revenue Requirement (3)	Cost of O&M (Storage)	Cost of O&M (Generation)	Cost of Property Taxes	Cost of Generation Tax	Cost of Integration	Cost of Wheeling (4)	Direct Assigned Rev Req w/o TV	Network Upgrade Rev Req w/o TV	CapEx Terminal Value	DA Terminal Value	NU Terminal Value	Net Delivery Cost	Net Benefit/(Cost)	Embedded Terminal Value
2024	$0	$0	$0	$1,958,327	($2,115,325)	($4,349)	$0	($164,383)	$0	$0	($100,710)	$0	$0	$0	$0	$0	$0	($426,439)	($426,439)	$0
2025	$0	$0	$0	$8,712,891	($11,026,576)	($38,916)	$0	($773,480)	($638,209)	$0	($579,575)	$0	$0	$0	$0	$0	$0	($4,343,865)	($4,343,865)	$0
2026	$0	$0	$0	$8,712,891	($10,291,609)	($99,865)	$0	($789,765)	($573,829)	$0	($613,933)	$0	$0	$0	$0	$0	$0	($3,656,110)	($3,656,110)	$0
2027	$0	$0	$0	$9,024,065	($9,757,806)	($158,662)	$0	($807,116)	($528,972)	($49,725)	($699,653)	$0	$0	$0	$0	$0	$0	($2,977,868)	($2,977,868)	$0
2028	$0	$0	$0	$9,058,022	($9,299,439)	($216,407)	$0	($824,111)	($495,808)	($214,137)	($736,491)	$0	$0	$0	$0	$0	$0	($2,728,371)	($2,728,371)	$0
2029	$0	$0	$0	$9,335,240	($8,897,650)	($273,535)	$0	($842,245)	($462,495)	($213,334)	($383,612)	$0	$0	$0	$0	$0	$0	($1,737,631)	($1,737,631)	$0
2030	$0	$0	$0	$9,335,240	($8,609,016)	($330,449)	$0	($860,734)	($437,953)	($213,334)	($351,831)	$0	$0	$0	$0	$0	$0	($1,468,077)	($1,468,077)	$0
2031	$0	$0	$0	$9,646,415	($8,376,960)	($387,838)	$0	($879,670)	($422,231)	($213,334)	($105,960)	$0	$0	$0	$0	$0	$0	($739,578)	($739,578)	$0
2032	$0	$0	$0	$9,995,059	($8,144,903)	($446,042)	$0	($899,023)	($406,443)	($214,137)	($140,535)	$0	$0	$0	$0	$0	$0	($256,023)	($256,023)	$0
2033	$0	$0	$0	$9,957,590	($7,912,846)	($505,129)	$0	($918,801)	($390,582)	($213,334)	($37,524)	$0	$0	$0	$0	$0	$0	($20,627)	($20,627)	$0
2034	$0	$0	$0	$7,875,253	($7,680,789)	($567,979)	$0	($962,664)	($374,639)	($213,334)	($27,507)	$0	$0	$0	$0	$0	$0	($1,951,659)	($1,951,659)	$0
2035	$0	$0	$0	$0	($7,448,733)	($667,338)	$0	($1,249,704)	($358,893)	($213,334)	($36,846)	$0	$0	$0	$0	$0	$0	($9,974,848)	($9,974,848)	$0
2036	$0	$0	$0	$0	($7,216,676)	($801,494)	$0	($1,277,198)	($346,303)	($214,137)	($31,830)	$0	$0	$0	$0	$0	$0	($9,887,637)	($9,887,637)	$0
2037	$0	$0	$0	$0	($6,984,619)	($935,256)	$0	($1,305,296)	($333,226)	($213,334)	($7,065)	$0	$0	$0	$0	$0	$0	($9,778,796)	($9,778,796)	$0
2038	$0	$0	$0	$0	($6,752,562)	($1,070,055)	$0	($1,334,013)	($319,750)	($213,334)	($6,641)	$0	$0	$0	$0	$0	$0	($9,696,355)	($9,696,355)	$0
2039	$0	$0	$0	$0	($6,520,506)	($1,206,715)	$0	($1,363,361)	($305,908)	($213,334)	($7,115)	$0	$0	$0	$0	$0	$0	($9,616,938)	($9,616,938)	$0
2040	$0	$0	$0	$0	($6,288,449)	($1,346,099)	$0	($1,334,013)	($291,668)	($214,137)	($30,406)	$0	$0	$0	$0	$0	$0	($9,504,771)	($9,504,771)	$0
2041	$0	$0	$0	$0	($6,056,392)	($1,489,509)	$0	($1,363,361)	($277,045)	($213,334)	($30,883)	$0	$0	$0	$0	$0	$0	($9,430,524)	($9,430,524)	$0
2042	$0	$0	$0	$0	($5,824,335)	($1,638,116)	$0	($1,394,718)	($262,044)	($213,334)	($31,485)	$0	$0	$0	$0	$0	$0	($9,364,032)	($9,364,032)	$0
2043	$0	$0	$0	$0	($5,592,279)	($1,793,054)	$0	($1,426,797)	($246,612)	($213,334)	($32,099)	$0	$0	$0	$0	$0	$0	($9,304,174)	($9,304,174)	$0
2044	$0	$0	$0	$0	($5,360,222)	($1,955,852)	$0	($1,459,613)	($230,685)	($214,137)	($32,848)	$0	$0	$0	$0	$0	$0	($9,253,357)	($9,253,357)	$0
2045	$0	$0	$0	$0	($5,128,165)	($2,128,616)	$0	($1,493,184)	($214,190)	($213,334)	($33,363)	$0	$0	$0	$0	$0	$0	($9,210,852)	($9,210,852)	$0
2046	$0	$0	$0	$0	($4,896,109)	($2,314,331)	$0	($1,527,527)	($197,032)	($213,334)	($34,014)	$0	$0	$0	$0	$0	$0	($9,182,346)	($9,182,346)	$0
2047	$0	$0	$0	$0	($4,664,052)	($2,517,380)	$0	($1,562,661)	($179,097)	($213,334)	($34,677)	$0	$0	$0	$0	$0	$0	($9,171,200)	($9,171,200)	$0
2048	$0	$0	$0	$0	($4,431,995)	($2,744,491)	$0	($1,595,476)	($160,235)	($214,137)	($35,486)	$0	$0	$0	$0	$0	$0	($9,181,821)	($9,181,821)	$0
2049	$0	$0	$0	$0	($4,199,938)	($3,006,615)	$0	($1,628,981)	($140,251)	($213,334)	($36,042)	$0	$0	$0	$0	$0	$0	($9,225,161)	($9,225,161)	$0
2050	$0	$0	$0	$0	($3,967,882)	($3,323,071)	$0	($1,663,190)	($118,871)	($213,334)	($36,745)	$0	$0	$0	$0	$0	$0	($9,323,093)	($9,323,093)	$0
2051	$0	$0	$0	$0	($3,735,825)	($3,732,315)	$0	($1,698,117)	($95,697)	($213,334)	($37,462)	$0	$0	$0	$0	$0	$0	($9,512,750)	($9,512,750)	$0
2052	$0	$0	$0	$0	($3,503,768)	($4,167,302)	$0	($1,733,778)	($70,086)	($214,137)	($38,336)	$0	$0	$0	$0	$0	$0	($9,727,406)	($9,727,406)	$0
2053	$0	$0	$0	$0	($3,271,711)	($4,426,329)	$0	($1,770,187)	($37,744)	($200,903)	($36,668)	$0	$0	$0	$0	$0	$0	($9,743,541)	($9,743,541)	$0
2054	$0	$0	$0	$0	($1,609,848)	($2,206,552)	$0	($1,156,468)	$2,189	($122,707)	($22,833)	$0	$0	$0	$15,807,629	$0	$0	$10,691,411	$10,691,411	$15,807,629
2055	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2056	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2057	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2058	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2059	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2060	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2061	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2062	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2063	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2064	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Totals	$0	$0	$0	$93,610,993	($195,566,984)	($46,499,660)	$0	($38,059,636)	($8,914,306)	($5,712,304)	($4,370,174)	$0	$0	$0	$15,807,629	$0	$0	($189,704,441)	($189,704,441)	$15,807,629

(1) No assumed price for the Market Value of RECs.
(2) Federal PTC and/or State Renewable Incentive
(3) Capital Revenue Requirement includes return on capital (7.460%) and capital depreciation expense.
(4) Cost of Transmission includes wheeling (PTP, Sch/Disp) and losses

Generation/Capacity

PV Generation MWh	PV Average MW	Capacity Factor	PV Capacity MW
2,152,805	3,802.6	45%	7,642

Adjusted by Capacity Contribution

ACC Value	Value of RE	Value of Sto	Market Valu	Capital Reve	RRCap Reve	Cost of O&M	Cost of O&M	Cost of Prop	Cost of Gene	Cost of Integ	Cost of Whe	Direct Assig	Network Up	CapEx Term	DA Termina	NU Termina	Net Delivery	Net Benefit/(	Embedded T	Adj Net Benefit/(Cost)
0	0	0	167.6188	-248.3767	-30.11217	0	-35.29449	-12.11801	-5.427358	-7.984682	0	0	0	7.0416095	0	0	-164.653	-164.653	7.0416095	-164.653
0	0	0	360850530	-5.35E+08	-64825610	0	-75982144	-26087713	-11684043	-17189460	0	0	0	15159210	0	0	-3.54E+08	-3.54E+08	15159210	-3.54E+08
0	0	0	47.216857	-69.96571	-8.482353	0	-9.942172	-3.413546	-1.528843	-2.24922	0	0	0	1.9835643	0	0	-46.38142	-46.38142	1.9835643	-46.38142
																	-68.76795	-68.76795		

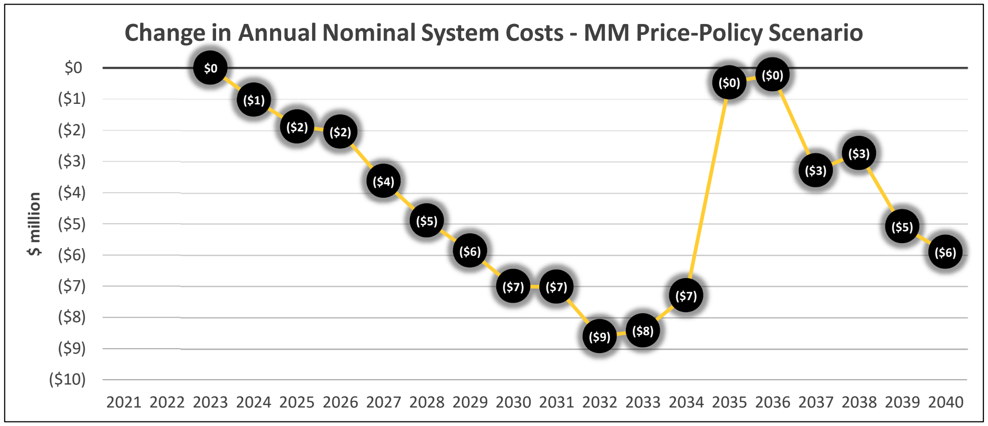
Annual

Adjusted by Capacity Contribution

Total MWh	Average MW	Average CF	Capacity MW	Cap Contrib	ACC Value	Value of RE	Value of Sto	Market Valu	Capital Reve	RRCap Reve	Cost of O&M	Cost of O&M	Cost of Prop	Cost of Gene	Cost of Integ	Cost of Whe	Direct Assig	Network Up	CapEx Term	DA Termina	NU Termina	Net Delivery	Net Benefit/(	Embedded T	Net Benefit/(Cost)						
49,725	34.0	63%	8.9	0.1459358	0	0	0	13419096	-14494893	-29800.69	0	-1126406	0	0	-690096.2	0	0	0	0	0	0	-2922101	-2922101	0	-2922101	-5775484	-9374411	3598927.3	3598927.3	0	
213,334	24.4	45%	53.6	0.1459358	0	0	0	59703567	-75557692	-266664.6	0	-5300138	-4373215	0	-3971436	0	0	0	0	0	0	-29765578	-29765578	0	-29765578	-6256340	-9541632	3285292.4	6884219.6	-2935438	-2486019
213,334	24.4	45%	53.6	0.1459358	0	0	0	59703567	-70521457	-684310.4	0	-5411725	-3932064	0	-4206866	0	0	0	0	0	0	-25052855	-25052855	0	-25052855	-6579003	-9762906	3183903.2	10068123	-2616131	-2427744
213,334	24.4	45%	53.6	0.1459358	0	0	0	61835838	-66863666	-1087203	0	-5530621	-3624687	-340733.9	-4794251	0	0	0	0	0	0	-20405323	-20405323	0	-20405323	-6820155	-10414647	3594492.6	13662615	-2397824	-2303287
214,137	24.4	45%	53.6	0.1459358	0	0	0	62068519	-63722789	-1482889	0	-5647081	-3397435	-1467335	-5046678	0	0	0	0	0	0	-18695687	-18695687	0	-18695687	-7009830	-11821202	4811371.6	18473987	-2235318	-2179077
213,334	24.4	45%	53.6	0.1459358	0	0	0	63968108	-60969600	-1874352	0	-5771337	-3169166	-1461834	-2628633	0	0	0	0	0	0	-11906814	-11906814	0	-11906814	-7367555	-8314728	947172.6	19421160	-2076067	-2054868
213,334	24.4	45%	53.6	0.1459358	0	0	0	63968108	-58991785	-2264343	0	-5898029	-3000997	-1461834	-2410861	0	0	0	0	0	0	-10059741	-10059741	0	-10059741	-7500585	-8280237	779651.87	20200812	-1959208	-1929229
213,334	24.4	45%	53.6	0.1459358	0	0	0	66100378	-57401657	-2657593	0	-6027786	-2893264	-1461834	-726075.7	0	0	0	0	0	0	-5067832	-5067832	0	-5067832	-7809769	-8243034	433265.56	20634077	-1884061	-1814253
214,137	24.4	45%	53.6	0.1459358	0	0	0	68489401	-55811528	-3056424	0	-6160397	-2785081	-1467335	-962989.7	0	0	0	0	0	0	-1754355	-1754355	0	-1754355	-8191210	-8218632	27422.358	20661499	-1808338	-1698845
213,334	24.4	45%	53.6	0.1459358	0	0	0	68232648	-54221400	-3461310	0	-6295926	-2676395	-1461834	-257129.8	0	0	0	0	0	0	-141346.3	-141346.3	0	-141346.3	-8416713	-8175585	-241127.2	20420372	-1739081	-1580340
213,334	24.4	45%	53.6	0.1459358	0	0	0	53963801	-52631272	-3891979	0	-6596487	-2567147	-1461834	-188489.3	0	0	0	0	0	0	-13373406	-13373406	0	-13373406	-8847566	-8317625	-529941.8	19890430	-1668619	-1461749
213,334	24.4	45%	53.6	0.1459358	0	0	0	0	-51041143	-4572819	0	-8563381	-2459249	-1461834	-252481.3	0	0	0	0	0	0	-68350908	-68350908	0	-68350908	-9291156	-8306497	-984659.3	18905771	-1597184	-1345122
214,137	24.4	45%	53.6	0.1459358	0	0	0	0	-49451015	-5492098	0	-8751776	-2372978	-1467335	-218108.5	0	0	0	0	0	0	-67753309	-67753309	0	-67753309	-9732712	-8284689	-1448023	17457748	-1524854	-1245138
213,334	24.4	45%	53.6	0.1459358	0	0	0	0	-47860886	-6408676	0	-8944315	-2283376	-1461834	-48410.72	0	0	0	0	0	0	-67007499	-67007499	0	-67007499	-10339353	-8248990	-2090363	15367385	-1451548	-1126356
213,334	24.4	45%	53.6	0.1459358	0	0	0	0	-46270758	-7332366	0	-9141090	-2191031	-1461834	-45507.87	0	0	0	0	0	0	-66442587	-66442587	0	-66442587	-10858062	-8310082	-2547980	12819405	-1377281	-1008496
213,334	24.4	45%	53.6	0.1459358	0	0	0	0	-44680630	-8268807	0	-9342194	-2096178	-1461834	-48752.41	0	0	0	0	0	0	-65898395	-65898395	0	-65898395	-11190855	-8348910	-2841945	9977459.7	-1302055	-978526.4
214,137	24.4	45%	53.6	0.1459358	0	0	0	0	-43090501	-9223907	0	-9141090	-1998604	-1467335	-208351.9	0	0	0	0	0	0	-65129789	-65129789	0	-65129789	-11563466	-8289946	-3273521	6703939.1	-1225755	-926084.3
213,334	24.4	45%	53.6	0.1459358	0	0	0	0	-41500373	-10206600	0	-9342194	-1898405	-1461834	-211618.5	0	0	0	0	0	0	-64621025	-64621025	0	-64621025	-11892513	-8529388	-3363124	3340814.9	-1148247	-759699.1
213,334	24.4	45%	53.6	0.1459358	0	0	0	0	-39910245	-11224903	0	-9557064	-1795612	-1461834	-215745	0	0	0	0	0	0	-64165402	-64165402	0	-64165402	-12262289	-8609574	-3652715	-311900.4	-1069373	-909960
213,334	24.4	45%	53.6	0.1459358	0	0	0	0	-38320116	-12286592	0	-9776877	-1689863	-1461834	-219952	0	0	0	0	0	0	-63755234	-63755234	0	-63755234	-12645335	-8831343	-3813993	-4125893	-988945.8	-890295.8
214,137	24.4	45%	53.6	0.1459358	0	0	0	0	-36729988	-13402137	0	-10001745	-1580730	-1467335	-225084.9	0	0	0	0	0	0	-63407020	-63407020	0	-63407020	-13073485	-8806926	-4266559	-8392452	-906739.9	-886323.4
213,334	24.4	45%	53.6	0.1459358	0	0	0	0	-35139860	-14585969	0	-10231785	-1467696	-1461834	-228613.8	0	0	0	0	0	0	-63115758	-63115758	0	-63115758	-13453258	-9003811	-4449447	-12841899	-822479.2	-747748.1
213,334	24.4	45%	53.6	0.1459358	0	0	0	0	-33549731	-15858547	0	-10467116	-1350127	-1461834	-233071.8	0	0	0	0	0	0	-62920427	-62920427	0	-62920427	-13879197	-9117763	-4761434	-17603333	-735819.1	-847449.1
213,334	24.4	45%	53.6	0.1459358	0	0	0	0	-31959603	-17249906	0	-10707860	-1227229	-1461834	-237616.7	0	0	0	0	0	0	-62844049	-62844049	0	-62844049	-14320530	-9214384	-5106146	-22709479	-646318.5	-854335
214,137	24.4	45%	53.6	0.1459358	0	0	0	0	-30369474	-18806150	0	-10932725	-1097983	-1467335	-243161.8	0	0	0	0	0	0	-62916829	-62916829	0	-62916829	-14813050	-9204172	-5608878	-28318358	-553394.3	-840706.3
213,334	24.4	45%	53.6	0.1459358	0	0	0	0	-28779346	-20602304	0	-11162312	-961042.3	-1461834	-246974.1	0	0	0	0	0	0	-63213813	-63213813	0	-63213813	-15251735	-11640340	-3611395	-31929752	-456241.9	-707528.7
213,334	24.4	45%	53.6	0.1459358	0	0	0	0	-27189218	-22770767	0	-11396720	-814541.9	-1461834	-251790.1	0	0	0	0	0	0	-63884871	-63884871	0	-63884871	-15742844	-14429940	-1312904	-33242657	-353681.2	-799326.9
213,334	24.4	45%	53.6	0.1459358	0	0	0	0	-25599089	-25575039	0	-11636052	-655745.7	-1461834	-256700	0	0	0	0	0	0	-65184460	-65184460	0	-65184460	-16251823	-14677641	-1574181	-34816838	-243815.7	-3276797
214,137	24.4	45%	53.6	0.1459358	0	0	0	0	-24008961	-28555708	0	-11880409	-480250.1	-1467335	-262690.4	0	0	0	0	0	0	-66655353	-66655353	0	-66655353	-16818996	-14991165	-1827831	-36644669	-123076.4	-3322970
200,903	22.9	43%	53.6	0.1459358	0	0	0	0	-22418833	-30330648	0	-12129897	-258631.1	-1376651	-251261.5	0	0	0	0	0	0	-66765921	-66765921	0	-66765921	-17326134	-19003192	1677058.2	-34967611	28779.363	-3413515
122,707	16.8	31%	44.6	0.112243	0	0	0	0	-14342520	-19658703	0	-10303254	19501.736	-1093222	-203422	0	0	0	140833986	0	0	95252366	95252366	140833986	95252366						-7088434
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	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	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	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	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	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	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	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	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	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	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0						
6,352,306					0	0	0	641453032	-1.34E+09	-3.23E+08	0	-2.63E+08	-61079224	-39394964	-29992821	0	0	0	140833986	0	0	-1.28E+09	-1.28E+09	140833986	-1.28E+09						

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
MM			$0	($1)	($2)	($2)	($4)	($5)	($6)	($7)	($7)	($9)	($8)	($7)	($0)	($0)	($3)	($3)	($5)	($6)

Figure 2 **Total-System Change in Annual Revenue Requirement Due to the Transmission Projects ($ million)**



Docket No. UE 433
Exhibit PAC/1000
Witness: Richard A. Vail

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Richard A. Vail

February 2024

TABLE OF CONTENTS

I. INTRODUCTION AND QUALIFICATIONS

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

A. My name is Richard A. Vail. My business address is 825 NE Multnomah Street, Suite 1600, Portland, Oregon 97232. I am the Vice President of Transmission at PacifiCorp. 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 direct 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, and specifically describe PacifiCorp's major capital investment projects for new distribution and transmission systems included in this rate case. These investments include transmission projects associated with Energy Vision 2024 (Gateway South, Gateway West Segment D.1, Gateway South Supporting projects, and the related generation interconnection network upgrades), a new 345 kilovolt (kV) transmission line, and a new 115–20.8 kV substation.

My testimony demonstrates that the Company's decisions are prudent, and that these investments result in an immediate benefit to PacifiCorp's Oregon customers. I recommend that the Public Utility Commission of Oregon (Commission) find these investments prudent.

III. OVERVIEW OF PACIFICORP'S TRANSMISSION SYSTEM

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

A. I provide an overview of PacifiCorp's transmission system, transmission reliability requirements, and standards and compliance mechanisms.

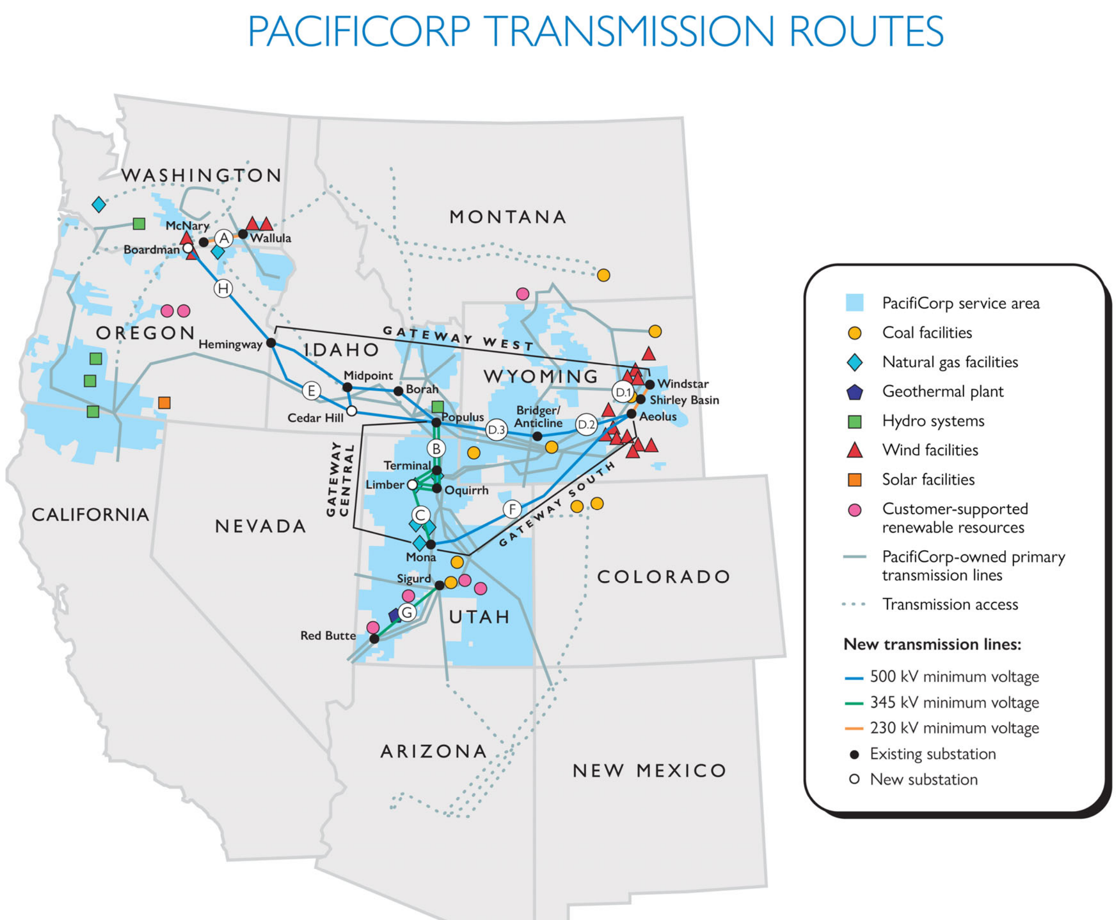
Q. Please provide a brief overview of the purpose of PacifiCorp's transmission system.

A. PacifiCorp's transmission system is designed to reliably transfer affordable electric energy from a broad array of generation resources to loads both within the Company's balancing authority areas (BAAs) and beyond, including other BAAs that PacifiCorp interconnects with, and participants in the California Independent System Operator's (CAISO) Western Energy Imbalance Market (WEIM).

Q. Please briefly describe PacifiCorp's transmission system.

A. As seen in the image below, PacifiCorp owns and operates approximately 17,770 miles of transmission lines ranging from 46 kV to 500 kV across multiple western states. PacifiCorp serves nearly two million customers with over 627,000 customers located in Oregon.

Figure 1



Resources depicted represent PacifiCorp's anticipated 2023 owned and customer-enabled purchase portfolio as identified in its 2019 Integrated Resource Plan. By the end of 2029, costs from coal-fired resources will not be included in rates for OR, WA and CA customers.

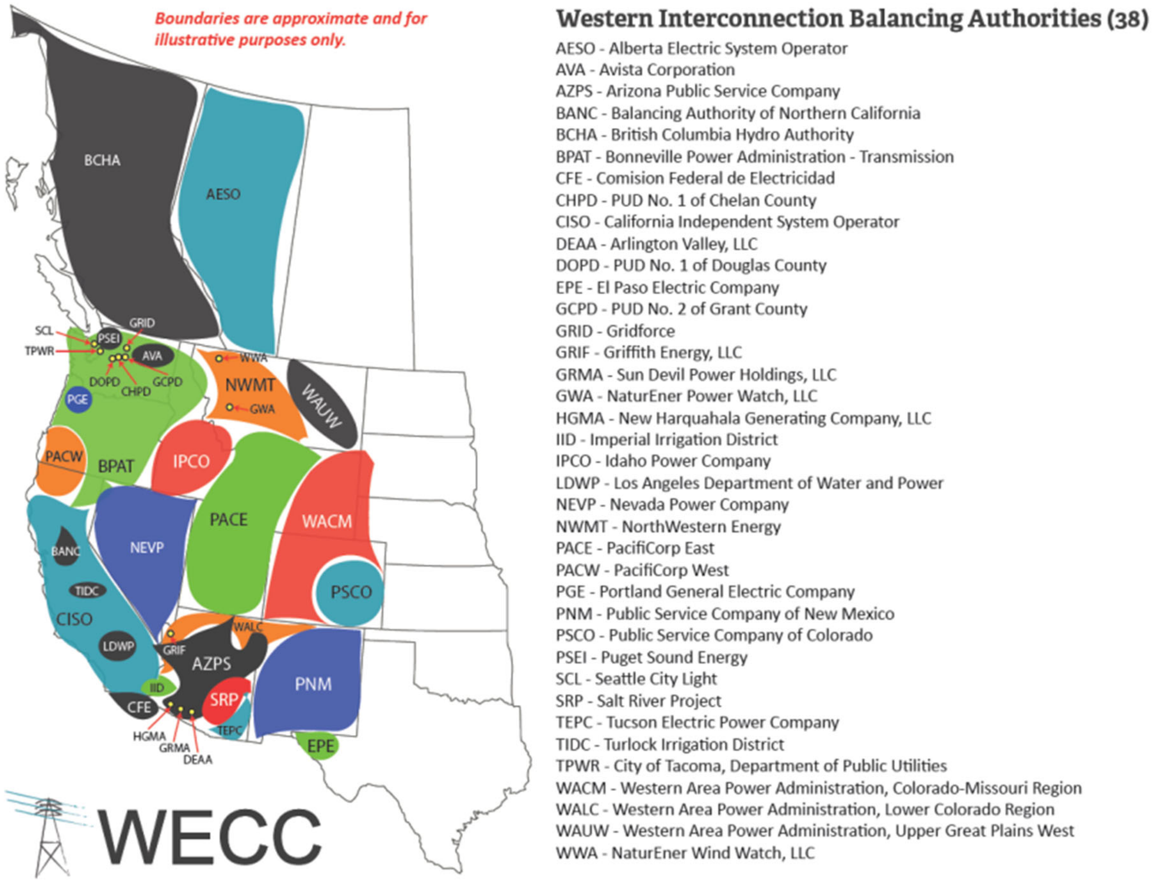
Q. What are Balancing Authorities and BAAs?

A. A Balancing Authority is the entity responsible for maintaining balance of load, generation, and interchange in a specific BAA, and supports interconnection frequency in real time. BAAs include all the generation, transmission, and loads within a specific metered region.

PacifiCorp is a Balancing Authority and manages two BAAs: PacifiCorp East (PACE) BAA and PacifiCorp West (PACW) BAA. The PACW BAA includes interconnections with the Bonneville Power Administration (BPA), northern points of CAISO, and other utilities in California, Oregon, and Washington. The PACE BAA interconnects with utilities in the intermountain west and southwest, and also provides access to the southern portion of the CAISO. As a Balancing Authority, PacifiCorp manages the production and consumption of electricity in these areas, by ensuring that there are adequate available generation resources or electricity transfers from other BAAs to meet load. As seen in the figure below, there are 38 BAAs in the Western Interconnection.[1]

[1] Available at https://www.wecc.org/Administrative/06-Balancing%20Authority%20Overview.pdf.

Figure 2



Q. How does PacifiCorp operate the two BAAs?

A. PacifiCorp separately balances each BAA for energy and load. To optimize dispatch for the benefit of customers, PacifiCorp dispatches generation across both BAAs to serve load across the entire system. Deliveries of energy over PacifiCorp's transmission system are managed and scheduled in accordance with the Federal Energy Regulatory Commission's (FERC) requirements. The flexibility of PacifiCorp's integrated transmission system provides options for optimizing dispatch to serve load and designating units for holding reserves, and provides for additional reliability during planned or unplanned generation outages. PacifiCorp also provides transmission service across both BAAs, meaning that a transmission customer can purchase transmission service from any point in one BAA to the other BAA, for a single tariff rate.

Q. Please describe PacifiCorp's responsibility for maintaining open access to its transmission system and creating stakeholder transmission planning processes.

A. In 1996, the FERC required transmission system owners like PacifiCorp to provide non-discriminatory access to their transmission systems for all transmission customers.[2] FERC expanded this open-access policy in 2011 by requiring transmission system owners to create regional, inter-regional, and local transmission planning processes.[3]

Under these authorities, the Company is required to provide non-discriminatory and reliable transmission and interconnection service according to the rates, terms, and conditions of PacifiCorp's OATT, and must engage in participant-driven planning processes covering its six-state transmission footprint.[4] These planning processes incorporate economics, reliability, and public policy inputs and requirements to develop comprehensive transmission development strategies.[5]

Where a request for transmission service cannot be reliably provided on the existing system, the Company's OATT and FERC policies require the Company to construct and expand its system to provide FERC-jurisdictional transmission and

[2] *See, In re Open Access Transmission Services*, Order No. 888, 75 FERC ¶ 61,080 (May 10, 1996).
[3] *See, In re Transmission Planning and Cost Allocation,* Order No. 1000, 136 FERC ¶ 61,051 (Jul. 21, 2011).
[4] *See,* PacifiCorp's Open Access Transmission Tariff Volume No. 11, Attachment K (updated Aug. 31, 2022) (available https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/20230208_OATTMaster.pdf).
[5] *See,* PacifiCorp's Open Access Transmission Tariff Volume No. 11, Attachment K (updated Aug 23, 2023) (available https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/20230823_OATTMaster.pdf) https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/20230208_OATTMaster.pdf).
[5] *See, e.g.,* PacifiCorp's Local Transmission System Plan (2022-2023 Biennial Cycle) (Dec. 31, 2023) (available https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/PacifiCorp__Local_Transmission_System_Plan_2022-2023_Report_Dec_31.pdf).

interconnection service.[6] This obligation to construct transmission facilities in response to transmission or interconnection service requests applies to both newly identified facilities and planned system expansions or upgrades.[7]

Q. Please describe PacifiCorp's responsibility for maintaining reliability on its transmission system.

A. In 2005, Congress directed the FERC to establish reliability standards to ensure the safe and reliable operation of the Nation's Bulk Electric System (BES).[8] The following year, the FERC adopted rules to implement the statute,[9] and delegated these responsibilities to the North American Electric Reliability Corporation (NERC).[10]

NERC proceeded to establish various reliability standards, including transmission system planning performance requirements (TPL Standards). NERC's TPL Standards establish, among other things, "Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions

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[6] PacifiCorp's OATT, §§ 28.2 and 15.4 (reflecting FERC's pro forma tariff and requiring PacifiCorp to construct facilities as necessary to reliably provide requested transmission service); *In re Standardized Generator Interconnection Agreements and Procedures*, Order No. 2003, 104 FERC ¶ 61,103 at 767 (2003) (explaining that FERC's pro forma interconnection services "provide for the construction of Network Upgrades that would allow the Interconnection Customer to flow the output of its Generating Facility onto the Transmission Provider's Transmission System in a safe and reliable manner."); *In re Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 118 FERC ¶ 61,119 at 814 (2007) (explaining that despite certain policy reforms, transmission providers "will continue to be obligated to construct new facilities to satisfy a request for service if that request cannot be satisfied using existing capacity")……………….

[7] *See, In re CAISO Tariff Revision,* 133 FERC ¶ 61,224 (2010) (OATT construction obligations attach to planned facilities identified as necessary to grant interconnection requests, stating that "[t]he fact that CAISO has voluntarily chosen to evaluate a network upgrade in its transmission planning process should not affect the obligation to build these facilities.").

[8] 16 USC § 824o.

[9] *In re Electric Reliability Standards Rulemaking,* 71 FR 8662-01, Docket No. RM05-30-000; Order No. 672 (Feb. 17, 2006).

[10] *In re NERC Certification,* 116 FERC ¶ 61,062 (Jul. 20, 2006), *aff'd Alcoa Inc. v. FERC,* 564 F.3d 1342 (D.C. Cir. 2009).

and following a wide range of probable Contingencies."[11] These TPL Standards, along with regional (*i.e.*, 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 NERC 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-state, stability, and short circuit analyses to evaluate peak and off-peak load seasons in the near-term (one-, two-, and five-year) and long-term (10-year) planning horizons.[12] 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 these annual system assessments, corrective action plans are developed to mitigate identified deficiencies, and may prescribe construction of

[11] *See* Standard TPL-001-5.1 — Transmission System Planning Performance Requirements, at A(3) (available https://www.nerc.com/pa/Stand/Reliability%20Standards%20Complete%20Set/RSCompleteSet.pdf) (last accessed Winter 2023-4).

[12] 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 to identify system deficiencies. For example: An N-1-1 event describes two transmission system elements 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 kilovolt transmission line followed by an unplanned outage of any additional element in the system being used to continue service with the initial element out.

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 or concurrent (N-1-1) transmission system events with allowed system adjustments performed between the two 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 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, that does not over-rely on operating procedure actions, is critical to ensuring system reliability so that large numbers of customers are not subjected to avoidable outage risk.

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 NERC or WECC reliability initiatives or investigations. Failure to comply with the reliability standards could expose the Company to penalties of up to $1.29 million per day, per violation.

Accordingly, reliability standards are a major driver for the new capital investments in PacifiCorp's system transmission assets that are identified in and supported by my testimony below.

Q. Are there additional concerns that influence PacifiCorp's distribution and transmission system investment decisions?

A. Yes. Depending on the project, there are several factors that inform whether PacifiCorp will build new distribution and transmission facilities, including increased demand for transmission capacity, requests for transmission service, increased demand for distribution capacity, and the age and condition of existing distribution and transmission facilities. The specific concerns for the projects addressed in my testimony are described in more detail below.

IV. CUSTOMER BENEFITS OF PACIFICORP'S TRANSMISSION SYSTEM

Q. Please describe how the PacifiCorp transmission system benefits Oregon customers.

A. PacifiCorp's transmission system is designed to reliably transport electricity from a broad array of generation resources to load across both BAAs, and the Company operates a geographically diverse and expansive transmission system serving retail customers in six western states. This unique geographic footprint, including over 17,770 miles of transmission lines, allows the Company to take advantage of efficiencies and economies from both a planning and operational perspective due to, among other things, retail load characteristics and variable resource diversity. PacifiCorp's transmission system provides over 200 interconnections with adjacent transmission provider BAAs as well as access to regional energy market hubs in Washington, the California-Oregon Border, Utah, the Four Corners area, and Arizona.

This geographic diversity, access to adjacent transmission providers and BAAs, and access to regional energy market hubs allows PacifiCorp to economically dispatch units across its system and transfer energy from other systems as facilitated by the Company's participation in the WEIM. This expansive footprint ensures that PacifiCorp is uniquely situated to access some of the nation's best wind and most cost-effective solar resources to serve customer load.

PacifiCorp also takes advantage of its transmission system to minimize operation costs related to generation reserve requirements and blackstart capability. The Company is required to carry reserves to ensure system reliability in the event of changes in load or system events. Instead of being required to carry reserves and blackstart capability in each individual BAA, PacifiCorp is able to operate its transmission as a collective system and use resources that are geographically remote to meet the system requirements in all areas that PacifiCorp serves. This allows the Company to engage in the most economic dispatch to lower costs for its customers.

Q. Does PacifiCorp currently carry reserves in each BAA sufficient to meet that BAA's requirements?

A. Not always. PacifiCorp often meets its reserve requirements in PACW with resources located in PACE. While meeting reliability standard reserve requirements is not a transmission function, PacifiCorp's transmission system provides flexibility for PacifiCorp to meet its reserve requirements.

Q. Are investments across the system necessary to maintain PacifiCorp's transmission system?

A. Yes. The ability to flexibly use a diverse set of energy resources depends significantly on the strength and reliability of PacifiCorp's transmission system to connect those resources to PacifiCorp's retail customers in all six states. Transmission system outages and other real-time operation constraints can unnecessarily burden the transmission system when corrective action plans are required to comply with NERC and WECC reliability authorities. Increasing PacifiCorp's transmission system capacity enhances reliability, allows more generation to interconnect to serve customer load, and provides flexibility in designating generation resources for reserve capacity to comply with mandatory reliability standards.

Q. Can the benefits of a reliable system be easily quantified?

A. No. Reliability is, essentially, the absence of system disruptions. It is very difficult to quantify the benefit of reliability investments. That said, the access to different regions and redundancy in operations provides reliable service under a variety of conditions that benefits all PacifiCorp's customers.

V. OVERVIEW OF INVESTMENTS

Q. What specific distribution and transmission system investments are you addressing in your testimony?

A. My testimony addresses PacifiCorp's major planned distribution and transmission system projects that will go in-service during the test period for this rate case. Each of these investments will increase PacifiCorp's load serving capability, enhance reliability, conform with NERC Reliability Standards, improve transfer capability within the existing system, relieve existing congestion, and interconnect and integrate new wind resources into PacifiCorp's transmission system. These projects include:

- The Gateway South Segment F Aeolus to Mona/Clover 500 kV and Gateway West Segment D.1 Windstar to Aeolus 230 kV Transmission Lines;
- The EV2024 Generation Interconnection Network upgrades;
- The Anticline 345 kV Phase Shifter;
- Gateway South Supporting Projects;
- The Oquirrh Terminal 345 kV Line Project.;
- The Path C Transmission Improvements Project; and
- The Conser Road- Construct new 115 kV to 20.8 kV Substation Project.

Q. What are the projected investment costs and their anticipated in-service dates?

A. Please see the table below for the total-Company costs and in-service dates for each project. These amounts include costs for engineering, project management, materials and equipment, construction, right-of-way, and an allowance for funds used during construction. These costs are detailed in the testimony and exhibits of Company witness Sherona L. Cheung. The in-service dates are based on our current best available information at the time of preparing this case.

TABLE 1

Project	Total-Company Cost (million)	Oregon-Allocated Cost (million)	Final In-Service Date
Gateway South	$2,097.4	$563.9	December 2024
Gateway West Segment D.1	$288.0	$77.4	Various - 2024
EV2024 Network upgrades	$40.1	$10.8	Various - 2024
Anticline 345 kV Phase Shifter	$133.5	$35.9	November 2024
Gateway South Supporting Projects	$20.2	$5.4	December 2024
Oquirrh Terminal 345 kV Line	$75.8	$20.4	November 24
Path C Transmission Improvements	$31.3	$8.4	May 2024
Conser Road - Construct new 115 kV to 20.8 kV Substation	$15.0	$15.0	September 2023

Q. Will PacifiCorp's OATT transmission customers pay their proportional share of these assets?

A. Yes. Transmission customers pay for transmission and ancillary services through the Company's transmission formula OATT rate.[13] Formula rates are updated by the Company's annual transmission revenue requirement (ATRR) filing that includes the total cost of providing firm transmission service over the test year.[14] This includes all transmission system investments made by the Company, a return on rate base, income taxes, expenses, and certain revenue credits, among other specific elements and adjustments.[15] Transmission assets, including the capital expenditures described in this rate case, will be included in the Company's annual ATRR filing when each asset is placed in service, weighted by months in service as necessary. This annual filing

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[13] *In re PacifiCorp's Application for Formula Rates*, 143 FERC ¶ 61,162 (May 23, 2013) (letter order approving settlement agreement establishing formula rate).
[14] *See, e.g.,* PacifiCorp's OATT Volume No. 11, Attachment H: ATRR for Network Integration Transmission Service, at 326–365 (available https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/20230208_OATTMaster.pdf).
[15] *Id.* at Attachment H-2: Formula Rate Implementation Protocols, at 366–386 (available https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/20230208_OATTMaster.pdf); *See, e.g., In re PacifiCorp's 2022 Transmission Formula Annual Update,* Docket No. ER11-3643 (May 13, 2022) (available https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/2022_Annual_update-Formula_rate_filing.pdf).

results in a wholesale customer rate by dividing the total ATRR by firm transmission demand. This rate is then assessed against PacifiCorp's transmission customers.[16]

Q. Do PacifiCorp's Oregon retail customers receive an offsetting revenue credit for a portion of the transmission revenue received under PacifiCorp's OATT?

A. Yes. A portion of PacifiCorp's transmission revenues are credited to the Company's state retail customers. Under this approach, the Company allocates 100 percent of its transmission costs to both state retail and FERC-jurisdictional customers. The FERC, through the Company's ATRR filings, determines the appropriate amount to be recovered from PacifiCorp's wholesale customers. This same amount is then credited to PacifiCorp's retail customers. This ensures that PacifiCorp recovers its transmission expenditures, and both wholesale and retail customers only pay their proportional share of the Company's transmission system.

The testimony below provides additional discussion and details for each of transmission investments that the Company seeks rate recovery for in this proceeding.

A. Gateway South and Gateway West Transmission Lines

Q. Please describe the Energy Gateway Transmission Expansion.

A. In 2007, PacifiCorp launched the Energy Gateway Transmission Expansion, a multi-year strategy to add approximately 2,000 miles of new transmission lines across the west. To date, three major segments of Energy Gateway are complete and in service.[17] After over a decade of planning, the Company now proposes to move forward with constructing the Gateway South and a portion of Gateway West lines

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[16] *See PacifiCorp's Transmission and Ancillary Services Rates* (effective Jun. 1, 2022) (available https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/Rate_Table_20220601-more_decimals.pdf).

[17] *See generally* https://www.pacificorp.com/transmission/transmission-projects/energy-gateway.html

(D.1).[18] The following graphic provides an overview of the Energy Gateway Transmission Expansion generally, and the Gateway South and Gateway West lines specifically.

Figure 3

This map is for general reference only and reflects current plans.
It may not reflect the final routes, construction sequence or exact line configuration.

Q. Please describe the Gateway South Transmission Project.

A. The Gateway South Project includes the following elements:

- A 416-mile, high voltage 500 kV transmission line from the Aeolus substation, near Medicine Bow, Wyoming to the Clover substation near Mona, Utah.
- Rebuilding certain 345 kV transmission facilities in and around the Mona and Clover substations in Utah.

[18] *See, e.g.,* PacifiCorp 2021 Integrated Resource Plan, Vol. 1, Ch. 4 – Transmission, at 83–102 (available 2021 https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2021-irp/Volume%20I%20-%209.15.2021%20Final.pdf.)

- Two new series compensation stations.
- Expansion of the Aeolus, Anticline, and Clover substations along with modifications to the Mona substation.
- Additional shunt capacitors at Bonanza (Utah), Riverton and Mustang (Wyoming) substations.
- Additions and modifications to various remedial actions schemes, voltage controllers and control schemes necessary to ensure protection and control of the grid after integration of Gateway South.

Q. Please describe the Gateway West Segment D.1 Transmission Project.

A. Gateway West Segment D.1 includes the following elements:

- A new 59-mile high-voltage, 230 kV transmission line from the Shirley Basin substation in southeastern Wyoming to the Windstar substation near Glenrock Wyoming.
- Rebuild of the existing Dave Johnston – Amasa – Difficulty – Shirley Basin 230 kV transmission line, which runs approximately 57 miles from the Shirley Basin substation in southeastern Wyoming to the Dave Johnston substation near Glenrock, Wyoming.
- A new 230 kV Heward substation adjacent to the Difficulty substation.
- Construction of four miles of high voltage 230 kV transmission line from the Aeolus substation to the Freezeout substation near Medicine Bow, Wyoming.
- Additions to the Shirley Basin, Dave Johnston, and Windstar substations.

Q. Please explain why the Gateway South and Gateway West Transmission Projects (collectively, the Transmission Projects) are needed.

A. The Transmission Projects are an important component of the Company’s Energy Gateway Transmission Expansion, and Gateway South has long been recognized as a key transmission segment in the region’s long-term transmission planning. These lines will provide substantial customer benefits.

For example, the Company needs additional resources to serve load by 2024, and the Transmission Projects enable new, cost-effective Wyoming generation resources to fill this need: these Transmission Projects allow the Company to interconnect up to approximately 2,030 megawatts (MW) of new resources. These projects will also improve reliability of the transmission system by providing capacity between Gateway West and Gateway Central and relieve transmission congestion on the existing Wyoming transmission system. The Gateway South line also allows transfers of up to 1,700 MW from eastern Wyoming to central Utah.

Q. Is the increased capacity provided by the Transmission Projects consistent with the Company's obligation to provide transmission service under its OATT?

A. Yes. PacifiCorp adhered to OATT processes when identifying the need for these transmission projects. In response to nearly 2,500 MW of transmission and interconnection service requests, the Company determined that the Transmission Projects were necessary to facilitate the various requests because PacifiCorp lacked adequate transmission capacity. As a result the Transmission Projects have been included in multiple FERC-jurisdictional executed contracts. For example, PacifiCorp has executed 13 contracts with third-party customers that require constructing one or both of the Transmission Projects, including a transmission service agreement that requires construction of Gateway South to reliably provide 500 MW firm point-to-point transmission service beginning by the contract start date of January 1, 2025. The Transmission Projects are lynchpins in PacifiCorp's ability to meet its obligation to grant generator interconnection service and transmission service under the OATT.

The Transmission Projects will also enhance the Company's ability to comply with mandated NERC and WECC reliability and performance standards. Congestion on the current transmission system in eastern Wyoming limits the ability to deliver energy from eastern Wyoming to PacifiCorp load centers in Wyoming, Idaho, Utah, and the Pacific Northwest.

Q. Do the Transmission Projects increase the amount of generation that can be interconnected and delivered across the Company's transmission system?

A. Yes. The Transmission Projects will allow the Company to interconnect an additional 2,030 MW of generation resources in eastern Wyoming and increase the system transfer capability by approximately 875 MW from the Windstar/Dave Johnston area south to Shirley Basin/Aeolus. This will create approximately 1,700 MW of incremental transfer capability from eastern Wyoming (Aeolus) to the central Utah energy hub (Mona/Clover).

Q. Did the Company consider alternatives to Transmission Projects?

A. Yes. PacifiCorp and Northern Grid (then the Northern Tier Transmission Group, an unincorporated association of entities that promotes coordinated, open, and transparent transmission planning and facilitates compliance with FERC transmission planning and reliability standards for the Pacific Northwest and Intermountain West) evaluated one alternative. This alternative analyzed one 345 kV line with bundled conductor from Aeolus to Anticline (138 miles), and two 345 kV lines with bundled conductors from Anticline to Populus (approximately 198 miles each), along with other supporting mitigation such as transformers and shunt capacitors at different substations.

These analyses indicated that the alternatives were less beneficial compared to the Gateway West and South projects for two reasons. First, these alternative lines would reduce the number of renewable resources that could be interconnected to eastern Wyoming by approximately 1,100 MW compared to Gateway West and South.

Second, this alternative also showed additional reliability issues on the transmission system between Rock Springs and Monument, and also between Populus and Terminal, that would have to be mitigated to comply with relevant reliability standards. This would result in additional cost burdens. Like the Aeolus to Clover line, this alternative does not provide an adequately diverse path for PacifiCorp's network loads.

These two considerations led the Company to conclude that Gateway West and South were more beneficial.

Q. If it did not construct the Transmission Projects, would the Company be able to provide the roughly 2,500 MW of interconnection and transmission service without constructing additional facilities?

A. No, it would not be possible to provide these requests for interconnection and transmission services with PacifiCorp's existing BES. For example, to grant only the 500 MW transmission service request, the Company would be required to construct a 230 kV line at a cost of approximately $1 billion. To grant the transmission and interconnection service requests, consistent with the Company's OATT, would require construction of the functional equivalent of the Transmission Projects.

Q. Has the Company obtained all necessary permits and rights-of-way (ROW) for the Transmission Projects?

A. Yes. All permits and ROW for both Gateway South and Gateway West Segment D.1 have been secured.

Q. When did PacifiCorp begin construction of the Transmission Projects?

A. Once the Company received necessary permits and ROW, the Company began construction of the Gateway South Project in June 2022, and late September 2022 for Gateway West Segment D.1.

Q. Is the Company confident that the Transmission Projects will be in service by 2024?

A. Yes. To manage construction schedule risk, the Company has structured and managed the projects on firm, date-certain, fixed-price, turnkey contracts. Construction contractors and equipment suppliers will be held to key construction and delivery milestones, guarantees, and development of compressed schedule mitigation plans, if required. The construction remains on-track and on schedule.

Q. Are the Transmission Projects currently on budget?

A. Yes. The project budgets based on contractual provisions require fixed cash flows that are assessed monthly against confirmed construction progress, in addition to identification and mitigation of project risks that could stall or delay completion. To date, almost 18 months from starting construction, both projects remain on budget.

Q. What are the remaining major milestones for the Transmission Projects?

A. Key milestones remaining before the in service date for these two projects include:

- Complete all wound core device deliveries by June 2024.

- Complete construction of the 500 kV transmission line and reconstruction of the 230 kV transmission line by October 2024.
- Complete all communications network additions and upgrades by October 2024.
- Complete construction of the 230 kV Windstar to Shirley Basin line by October 2024.
- Complete reconstruction of the 230 kV transmission line by November 2024.
- Complete commissioning and placed in-service in fourth quarter of 2024.

The Transmission Projects are on track to achieve each milestone.

B. <u>EV2024 Network Upgrades</u>

Q. What are network upgrades?

A. Network upgrades are the modifications or additions to transmission-related facilities that are integrated with and support PacifiCorp's overall Transmission System for the general benefit of system users.[19]

Q. Please explain how network upgrade cost allocation works under the OATT.

A. When PacifiCorp receives a request for generation interconnection or transmission service, the Company completes various studies to determine what new facilities or upgrades to existing facilities are required to accommodate the request.[20] The studies classify any required additions to support the requested service into two categories: direct assigned or network upgrade. Direct-assigned assets 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 rates. Network upgrades, on the

[19] *See, e.g.,* PacifiCorp's OATT Volume No. 11, § 1.27 (available https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/20230208_OATTMaster.pdf)
[20] *Id.* §§ 38–43.

other hand, benefit all customers that use the transmission system. Network upgrade costs can be included in PacifiCorp's ATRR, and ATRR revenues, are then credited to PacifiCorp's retail customers in each state.[21]

Q. Is the Company requesting recovery of any Generation Interconnection Network Upgrades?

A. Yes. There are five generation interconnection projects that were selected from a recent request for proposal to interconnect 1,640 MW of new wind generation to the Company's transmission system in eastern Wyoming. The request for proposal process and the resulting resources selected are described in the testimony of Company witness Rick T. Link. A separate generation interconnection agreement was negotiated and signed for all five projects, and each will require generation interconnection network upgrades to interconnect and integrate with PacifiCorp's system. These projects include:

- Q0409 Boswell Springs Wind. This project is a 320 MW wind facility that will interconnect to the existing Freezeout 230 kV substation near Aeolus and is planned to be in service by December 31, 2024. This project includes a new breaker at the Freezeout substation, and a new remedial action scheme and communications equipment at Aeolus substation.

- Q0713 Cedar Springs IV Wind. This project is a 350 MW wind facility that will interconnect to the existing Yellowcake 230 kV substation near Windstar, and is planned to be in service on January 15, 2025. This project includes construction of a new line position at the Yellowcake substation, including the installation of three new 230 kV circuit breakers, and requires a new microwave system and approximately 18 miles of fiber optic cable between Yellowcake and Windstar substations.

- Q0785 Anticline Wind. This project is a 100 MW wind facility that will interconnect to a new substation on PacifiCorp's Casper – Claim Jumper 230 kV line and is planned to be in service on December 31, 2024. This project includes a new three breaker ring bus substation on the Casper – Claim

[21] *Id.* 47.

Jumper 230 kV line, substation loop in on transmission line, communications upgrade at Casper substation, and Main Grid operations center updates.

- Q0835 Rock Creek Wind. This project is a 190 MW wind facility that will interconnect to PacifiCorp's existing Foote Creek 230 kV substation and is planned to be placed in service on December 15, 2024. This project includes expansion of substation, bus, and line position at Foote Creek substation, expansion for new breaker and line positions at Freezeout and Aeolus substations, construction of new approximately 3.5 miles long 230 kV transmission line between Aeolus and Freezeout substations.

- Q0836 Rock Creek Wind 2. This project is a 400 MW wind facility that will interconnect to PacifiCorp's existing Aeolus 230 kV substation and is planned to be placed in service on December 15, 2024. This project includes a new bay for a 230 kV line terminal at Aeolus substation.

Q. Why are these projects classified as network upgrades, and not directly assigned assets?

A. The interconnection study for each project indicated that these upgrades would provide system-wide benefits. Under PacifiCorp's OATT, this requires the Company to include these costs in the Company's ATRR, as opposed to directly assigning these costs to each project. Accordingly, the network upgrade costs for each of these projects are reflected in their respective Large Generator Interconnection Agreements.

Q. Is the Company confident that it can manage any construction schedule risk and deliver the network upgrades for the new wind facilities by the planned in-service dates?

A. Yes. To manage construction scheduling risk, the Company structured each network upgrade contract on a firm, date-certain, turnkey contract basis. Construction contractors and equipment suppliers are being held to key construction and delivery milestones and development of compressed schedule mitigation plans, if required. The Company also established construction contract completion dates and backstopped them with guarantees. To date, the remaining network upgrades remain on track for planned in-service dates.

C. <u>Anticline 345 kV Phase Shifter</u>

Q. Please describe the proposed Anticline 345 kV Phase Shifter Project.

A. The Anticline 345 kV Phase Shifter project will install four 345 kV phase shifting transformers (533.3/597.3 megavolt amperes (MVA) each (summer normal/4-hour emergency), +40/-40 degrees) at Anticline substation, near Point of Rocks, Wyoming.

Q. Please explain why these projects are needed and beneficial.

A. With the addition of the Gateway South Project, the phase shifters at Anticline are needed to enhance Wyoming transmission utilization and maximize the production of eastern Wyoming wind generation. By utilizing the phase shifters at Anticline, flows on the Aeolus – Bridger/Anticline line can be actively controlled to unload the underlying 230 kV system west of Aeolus, and manage flows on the Aeolus – Clover 500 kV (Gateway South) and the Aeolus-Anticline 500 kV transmission line to within its limits. If the Gateway South transmission path rating limit is exceeded, eastern Wyoming wind generation must be curtailed, and the phase shifters help prevent unnecessary curtailment.

Q. Did PacifiCorp consider alternatives to investing in the Anticline 345 kV Phase Shifter project?

A. Yes. Other transmission path power flow control methods, such as multi-segment series capacitors, has previously been investigated; however, the installation of phase shifting transformers at Anticline to provide active control flows on the Anticline – Bridger 345 kV line was shown to be the most efficient and cost effective. In addition, adding more than 70 percent series compensation on the transmission line is not preferred, and it would limit the applicability of this proposed alternative.

D. <u>Gateway South Supporting Projects</u>

Q. Please describe the Gateway South Supporting Projects.

A. The Gateway South (Aeolus – Clover) Project is a long high voltage transmission line that required additional supporting projects to enhance Wyoming transmission utilization and maximize the production of eastern Wyoming wind generation. These additional supporting projects include:

- Install one 41.6 megavolt amperes reactive MVAr shunt capacitor bank at Riverton 230 kV substation, install two 30 MVAr shunt capacitor banks at Mustang 230 kV substation, and one 60 MVAr shunt capacitor bank at Bonanza (Deseret owned) 138 kV substation. These facilities help maintain the flows and voltage reliability at each substation.
- Modification to the Aeolus remedial action scheme (RAS) to add Gateway South line logic and additional wind projects as part of the wind selection logic.
- Modifications to the Bridger RAS to support additional wind generation.
- Implementation of a new fast voltage controller (FVC) at Aeolus substation prevent high voltages for the loss of 500kV lines under heavy load scenarios.
- Modification of the existing Master Grid Controller at Aeolus, to accommodate the addition of the new windfarms.
- Development of operating procedures to mitigate N-1-1 loss of the two 230 kV paths from Dave Johnston/Windstar area to Aeolus.
- Modifications to the Energy Management System (EMS) to support monitoring flows on the transmission paths.

Q. Please explain why these projects are needed and beneficial.

A. The shunt capacitor banks will support additional power flows through the

Riverton – Wyopo 230 kV and Mustang – Bridger 230 kV lines under outage conditions, and will also alleviate low voltage issues. This is because the loss of transmission lines from Dave Johnston/Windstar to the Aeolus area diverts all the energy resources in the Dave Johnston/Windstar area towards the Riverton - Wyopo 230 kV and Mustang – Bridger 230 kV lines, and causes low voltages on the Riverton and Mustang 230 kV buses. Without the shunt capacitor banks, the outage would require significant reductions in wind generation to maintain power flows and voltage reliability at the Mustang and Riverton 230 kV buses. The Bonanza shunt capacitor bank is owned by Deseret, and an agreement has been signed for them to install with PacifiCorp reimbursing their costs.

Modifying the Aeolus RAS is required to add the Gateway South line in the logic, to trip 627 MW of wind generation for the loss of any of the Gateway South elements from Aeolus to Clover. For the Bridger RAS, until the Bridger units are available for tripping, minor changes might be required, but if the Bridger units are retired while keeping the 2400/2200 MW path limit, then additional wind generation will have to be included in the Bridger RAS for tripping.

The Aeolus FVC is designed to prevent high voltage at Aeolus 500 kV and Aeolus 230 kV bus for the loss of either line. Because Gateway South requires three new 200 MVAr shunt capacitors on the Aeolus 500 kV and 230 kV substations, planning studies have demonstrated that the loss of either 500 kV line could result in high voltages if the shunt capacitors banks are not tripped quickly. Manually tripping shunt capacitors is a complex task, because it depends on evaluating real-time and anticipated power flow levels, and which 500 kV lines are in-service. It is difficult to implement this logic as part of a comprehensive protection scheme. Instead, the Aeolus FVC is designed to automatically and quickly trip the shunt capacitor banks and prevent high voltages for the loss of 500 kV lines.

Developing an operating procedure for the Windstar area for the N-1-1 loss of the two 230 kV transmission paths from Dave Johnston/Windstar area to Aeolus would require generation curtailment to prevent thermal overloads and low voltage issues in the Casper, Riverton, Thermopolis, and Mustang areas. The operating procedure will identify the list of generators that can be curtailed along with the list of contingencies for which the curtailment may be necessary depending on dispatch scenarios.

Q. Did PacifiCorp consider alternatives to these supporting projects?

A. Yes. There were two alternatives considered instead of installing of the shunt capacitors at Mustang and Riverton. The first was additional transmission from the Dave Johnston/Windstar area to Aeolus, similar to Gateway West segment D.1 (Windstar – Shirley Basin), and the second was installing a +/- 100 MVAR Static Var Compensator at Casper. The installation of the shunt caps however was deemed to be the most efficient and cost-effective option.

The Company also considered alternatives to the Aeolus RAS modification requirements, which would result in additional transmission from Aeolus – Clover. This would be a significant cost compared to modification of the RAS. In addition, without the RAS modification, the amount of renewable resources that could be integrated into the eastern Wyoming system would be reduced by approximately 400-500 MW.

The Company also considered alternatives for the Jim Bridger RAS modification, which would result in additional new transmission between Jim Bridger and Populus (approximately 200 miles of new 345 kV line). Similar to the Aeolus RAS modification, this would be a significant cost as compared to the modification of the RAS. In addition, without the RAS modification, PacifiCorp would not be able to achieve the full path rating on Bridger West under different operating conditions such as high wind and low Bridger generation.

E. <u>Oquirrh Terminal 345 kV Line Project</u>

Q. Please describe the Oquirrh Terminal 345 kV Line Projects.

A. This project involves the construction of a new 14-mile double circuit, 345 kV transmission line between the Company's Oquirrh substation in West Jordan, Utah, and Terminal substation in Salt Lake City, Utah. This transmission line will link together the previously completed Mona to Oquirrh and Populus to Terminal transmission lines, which were both part of the Gateway Central portion of the Energy Gateway Transmission Expansion.

Q. Please explain why this project is needed and beneficial.

A. This project mitigates transmission constraints that currently exist between the Mona area and Wasatch front, and will improve system reliability and operational redundancy.

For example, the northbound transmission capacity on the Wasatch Front South (WFS) internal transmission cut plane (a 4,945 MW rating) is currently fully utilized,[22] and transmission planning studies show that new transmission facilities are necessary to meet anticipated network load service, reliability, contractual point-to-point commitments and enhance WEIM benefits. There are also ongoing requests to interconnect additional renewable generation resources in southern Utah and transmit the energy north that further exceed the transmission capacity on the WFS path north of Mona. Additionally, the Company anticipates that future Gateway South transfers into the Mona/Clover area will exacerbate an already constrained transmission system, and will require the Oquirrh-Terminal double circuit line to increase northbound transfers across the WFS transmission path. Finally, NERC TPL-001-4, requirements P1 and P7 mandate increased transmission system reliability and operational redundancy in the area under all expected operating conditions.

The Oquirrh – Terminal double circuit transmission line, in conjunction with the companion projects, addresses each of these issues. It enhances transmission system reliability and operational redundancy within the Wasatch Front by adding additional capacity. This additional transmission capacity also avoids 1,800 MW of curtailment to the WFS cut plane, and also a similar reduction of the equivalent amount of renewable or conventional generators in southern/central Utah, that would otherwise be required to reduce congestion. This increased capacity also avoids the increase stress on the transmission system from Wyoming to the west and northern Utah that otherwise would be used to serve load in the northwest. Additionally, without this new transmission, under system-outage conditions, load shed of up to

[22] Previous technical studies have determined the current WFS transfer capability to be 4945 MW, prior to addition of the Oquirrh – Terminal 345 kV line addition and associated companion projects. At 4945 MW, the WFS path is 100 percent committed (2016), prior to the addition of the Gateway South transmission project.

1,350 MW may be required to reduce thermal overload below its 30-minute emergency rating. This could potentially increase up to 2,500 MW to bring the transmission facilities below its continuous rating and normal operation without the new transmission line.

Q. Did PacifiCorp consider alternatives to investing in the Oquirrh Terminal 345 kV Line?

A. Yes. PacifiCorp took an iterative approach for resolving system limitations to increase transmission capacity on WFS cut plane. This transmission cut plane helps resources from southern Utah move north to serve load, as well as export power further north and to the northwest. Based on the Wasatch Front South Study Table 6 posted on PacifiCorp's OASIS,[23] PacifiCorp first identified an alternative mitigation to resolve the same system limitation (simultaneous outage of two Oquirrh – Terminal #1 & 2 345 kV lines). This alternative only allowed for a certain amount of capacity increases before the same limitation was observed again, and no other alternative mitigations were available to increase transmission capacity between Oquirrh and Terminal other than adding new transmission. The Company's Oquirrh Terminal 345 kV project adds new transmission, though provides a higher increase in transmission capacity that allows additional resources to move south-to-north compared to the alternative case.

[23] Available here: https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/Wasatch_Front_South_Boundary_Capacity_7_29_2021.pdf

F. Path C Transmission Improvement Project

Q. Please describe the Path C Transmission Improvement Project.

A. The Path C Transmission Improvement project adds a new 345/138 kV source in northern Utah and southeast Idaho by looping the existing Populus - Terminal 345 kV line in and out of the Bridgerland and Ben Lomond substations. The project also includes upgrades at Bridgerland substation, including a 345/138 kV 700 MVA autotransformer; a new 345 kV bus; three 345 kV breakers; and four 138 kV breakers. This new 345/138 kV source will improve the reliability of the 138 kV system, which runs parallel to Path C and will eliminate system limitations on the parallel 138 kV lines. It will also help maintain Path C ratings as well as add operational flexibility under outage conditions at Ben Lomond substation.

Q. Please explain why these projects are needed and beneficial.

A. The Path C Transmission Improvement project resolves N-2 issues that were identified as part of a NERC FAC-013 Assessment of Transfer Capability for the Near-Term Transmission Planning Horizon. This assessment was conducted to maintain WECC Path C ratings to 1,600 MW southbound, and 1,250 MW northbound. The project also adds a new 345/138 kV source in northern Utah and southeast Idaho which improves the reliability of the 138 kV system, which runs parallel to Path C and adds operational flexibility under outage conditions at Ben Lomond substation.

Q. Did PacifiCorp consider alternatives to investing in the Path C Transmission Improvement project?

A. Yes. The first alternative considered was to rebuild 6.3 miles of Oneida – Treasureton line, 29.5 miles of the Treasureton – Wheelon 138 kV line, expand the Bridgerland 138 kV substation, and loop in the Honeyville – Wheelon 138 kV line in and out of the substation. However, this alternative only resolves issues related to Path C southbound flows. To resolve northbound issues on Path C, an additional rebuild of 22.6 miles of double circuit line from Ben Lomond – Honeyville and 9 miles of Ben Lomond – White Rock 138 kV line would still be required. These alternatives were higher costs than the Company's primary choice.

G. Conser Road - Construct New 115 kV to 20.8 kV Substation Project

Q. Please describe the Conser Road - Construct New 115 kV to 20.8 kV Substation Project.

A. The Conser Road New Substation project is a new 115 kV to 20.8 kV distribution substation that went into service in September 2023. The new substation includes one 30 MVA 115–20.8 kV transformer with one switchgear and a two-stage capacitor. Scope to move voltage transformers to Conser Road substation from Murder Creek substation has been delayed to June 2024 due to outage scheduling.

Q. Please explain why these projects are needed and beneficial.

A. The new substation provides 30 MVA of initial capacity, expandable up to 120 MVA of total capacity, for industrial development in the Millersburg area. This new substation frees capacity at Murder Creek to supply additional load in the south Millersburg and Northeast Albany area, and also frees capacity at Murder Creek for the heavily loaded Queen Avenue or Vine Street substations.

This project, in combination with the Hazelwood Ring Bus and reconductoring a 0.28-mile section of the Murder Creek to Conser Tap line (at the Murder Creek end), will fully address the known TPL deficiencies in the Willamette Valley transmission system, and effectively eliminate the need to perform 12 switching operation to change the system to a radial configuration following a single contingency.

Q. Did PacifiCorp consider alternatives to investing in the Conser Road - Construct New 115 kV to 20.8 kV Substation?

A. Yes. The only alternative for the distribution substation capacity issue would be to construct two new distribution substations, one near Murder Creek and the other in the North Albany area, however this would be a more costly solution because it would require construction of a second substation.

VI. CONCLUSION

Q. Please summarize your testimony.

A. I recommend that the Commission conclude that the projects described above are prudent.

Q. Does this conclude your direct testimony?

A. Yes.

REDACTED
Docket No. UE 433
Exhibit PAC/1100
Witness: Timothy J. Hemstreet

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Direct Testimony of Timothy J. Hemstreet

February 2024

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 Company).

A. My name is Timothy J. Hemstreet. My business address is 825 NE Multnomah Street, Suite 1800, Portland, Oregon 97232. My present position is Vice President of Renewable Energy Development for PacifiCorp.

Q. Briefly describe your education and business 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. Prior to joining the Company in 2004, I held positions in engineering consulting and environmental compliance. Since joining the Company, I have held positions in environmental policy, engineering, project management, and hydroelectric project licensing and program management. In 2016, I assumed a role in renewable energy development, and in June 2019 I assumed the Managing Director role focusing on PacifiCorp's wind repowering effort, and assumed my current role in September 2022, 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 AND SUMMARY OF TESTIMONY

Q. What is the purpose of your direct testimony?

A. The purpose of my testimony is to demonstrate the prudency of the Company's efforts to acquire and repower the Rock River I wind energy facility. My testimony provides detail on the Company's commercial and other arrangements related to Rock River I and explains their customer benefits. Specifically, for Rock River I my testimony addresses the background and relationship to the Company's earlier repowering efforts; relevant contracting arrangements, implementation status, permitting status, and schedule; and energy and financial benefits for customers that result from re-qualification for production tax credits (PTC).

Additionally, my testimony describes the Company's investments to construct a new Fall Creek Hatchery and describes how this project is consistent with the requirements of the Federal Energy Regulatory Commission (FERC) and the Klamath Hydroelectric Settlement Agreement (KHSA).

Q. Please summarize your Rock River I testimony.

A. PacifiCorp completed a significant repowering of its owned wind fleet in March 2021, and the Company has built on these efforts by acquiring and repowering additional wind facilities adjacent to the Company's Foote Creek I facility, including Rock River I. This project will allow the Company to leverage existing long-term wind energy lease rights, facilities, and infrastructure in the area (including staff and contractor resources) that will provide customers with the enhanced benefits that come from repowering cost-effective, proven high-capacity-factor wind energy resources. Acquiring and repowering Rock River I is consistent with the Company's

2021 and 2023 Integrated Resource Plans, that identified the resource as beneficial to customers and included acquiring and repowering the project in the Company's least -cost, least risk preferred portfolio.[1] Construction of Rock River I began in the summer of 2023, and the project is expected to be commercially operational in December 2024.

Q. Please summarize your Fall Creek Hatchery testimony.

A. The Company is building a new fish hatchery adjacent to the Fall Creek Hydroelectric Plant, which is the remaining operating Company-owned hydro development within the Klamath Hydroelectric Project. The hatchery is necessary for the Company to meet its obligations under the KHSA, and a July 13, 2022, Memorandum of Agreement with the States of California and Oregon, to support continued fish production for an eight-year period following Klamath dam removal.[2] The facility has been designed in consultation with the California Department of Fish and Wildlife (CDFW) and the National Marine Fisheries Service (NMFS) specifically to meet fish production goals following the removal of Iron Gate Dam. Construction of the facility is nearly complete, and the new hatchery started accepting fish in November 2023 to ensure fish production would continue following the removal of Iron Gate dam which recently began in January 2024. The hatchery will fulfill the Company's obligations under the KHSA, and as a required implementation action of that agreement, protects customers from uncertain costs and risks related to further operation of the Klamath hydro assets.

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[1] *In re PacifiCorp 2021 Integrated Resource Plan,* at 295, 323 (https://www.pacificorp.com/energy/integrated-resource-plan.html).
[2] *See* KHSA 7.6.6 and Interim Measures 18-19.

III. RELATION TO PRIOR REPOWERING PROJECTS

Q. Please explain the background of the Rock River I wind energy project.

A. The Foote Creek Rim wind energy projects were the first utility-scale, commercial wind energy projects in the State of Wyoming. Rock River I is located adjacent to the Foote Creek Rim due to the extraordinary combination of geography and wind energy resources in this location that cause already robust winds to accelerate as they move over the elevated plateau of the Foote Creek Rim and the Rock River I project site. Development of wind energy facilities to take advantage of these favorable wind energy characteristics began in the early 1990s, and the Rock River I wind project is located approximately five miles northeast of the Foote Creek Rim projects and four miles northwest of the High Plains and McFadden Ridge projects. Rock River I was developed shortly after the Foote Creek Rim projects, and reached commercial operation in October 2001.

Rock River I was originally constructed with 50 wind turbines (each turbine with a nameplate capacity of one megawatt (MW)) with a total nameplate capacity of 50 MW. Rock River I was previously co-owned by Terra-Gen and Shell Wind Energy Inc. (Shell) and its output was sold to the Company under a 20-year power purchase agreement that expired in December 2021. The Rock River I project interconnects to the Company's transmission system at the Foote Creek Substation.

Q. What does it mean to repower a wind energy facility?

A. Repowering a wind energy facility means upgrading the wind turbine generator (WTG) equipment at an existing wind energy project with more efficient equipment to increase the power generation from the facility and extend the life of the facility.

Specifically, repowering Rock River I involves installing new turbines while reusing other pre-existing facility infrastructure.

Q. Please briefly describe PacifiCorp's effort to repower the Rock River I facility.

A. Similar to the Company's effort to repower the neighboring Foote Creek I-IV facilities, repowering of Rock River I involves installing new WTGs to replace the smaller capacity turbines originally installed. The 19 new WTGs at Rock River I will be supported on new foundations and connected to the Foote Creek Substation with new energy collector circuits. The turbines will have updated switchgear and controls, and the new WTG locations will be linked by new turbine access roads. The Rock River I site layout is shown in Exhibit PAC/1101.

Q. Will Rock River I benefit from PacifiCorp's prior efforts to repower adjacent facilities?

A. Yes. The Rock River I facility will benefit from the Company's recent repowering effort at the nearby High Plans and McFadden Ridge projects, utilizing operations and maintenance staff contracted for that project to also operate the Rock River I facility. Thus, no additional operations facilities are needed to support project operations. Some project controls will also be housed at the Company's Foote Creek operations and maintenance building, which is nearby the Foote Creek Substation, where Rock River I will interconnect to the transmission system. This local infrastructure results in efficiencies and cost savings for the project since it can draw on existing infrastructure as well as Company staff and contractor resources.

Q. Will the larger blades from the new turbines increase the potential for avian impacts at Rock River I?

A. Monthly monitoring conducted at Rock River I over the last several years shows no significant avian impacts. Although the larger blades and greater rotor-swept area will increase the overall risk zone of the repowered wind turbines, this does not necessarily correlate with an increased risk of avian impacts. The significant reduction in the number of turbines that will be deployed at the site also means that less of the overall project site area will be covered by wind turbines. To further mitigate any potential impacts, the new turbine locations have been sited to avoid areas of higher avian use such as the edges of the plateaus, and existing overhead energy collector lines will be upgraded to implement design improvements intended to reduce avian exposure risk.

The Company also performs monthly monitoring at all Company-owned Wyoming wind facilities and reports to both the Wyoming Game and Fish Department and the United States (U.S.) Fish and Wildlife Service. Once repowering concludes, the Company will begin this monthly monitoring at Rock River I to determine if the new turbines cause additional impacts to avian species and will engage with the appropriate agencies to discuss and, if prudent and practicable, implement additional avoidance, minimization, or mitigation measures. The Company has prepared an Eagle Conservation Plan and will develop a Bird and Bat Conservation Strategy for the new turbines in consultation with both the Wyoming Game and Fish Department and the U.S. Fish and Wildlife Service.

IV. CONTRACTING, PERMITTING STATUS, SCHEDULE, AND COST

Q. What commercial arrangements has PacifiCorp made to acquire and repower Rock River I?

A. The Company negotiated a Purchase and Sale Option Agreement (PSOA) with Terra-Gen and Shell to acquire 100 percent of their interests in the Rock River I facility including the project's wind energy lease rights, transmission and access easements, and interconnection agreement. Under the PSOA, Terra-Gen and Shell removed the original 50 turbines from the site and completed site restoration activities in preparation for repowering of the site by the Company. The Company closed on the acquisition of the facilities under the PSOA on February 10, 2023. Repowering construction activities began in the second quarter 2023, in support of a planned late 2024 in-service date for the project.

Q. What other commercial arrangements has PacifiCorp made with respect to Rock River I?

A. The Company executed a safe harbor purchase agreement and a turbine supply agreement with General Electric International, Inc. (GE) in which GE will supply and commission WTGs suitable for the site. The Company has also executed a balance of plant wind energy construction services contract. The Company has also executed a turbine full-service agreement with GE under which GE will maintain the repowered turbines consistent with negotiated pricing and terms.

Q. What is the status of necessary permitting to begin construction of the repowering projects?

A. The Company has received the necessary Federal Aviation Administration no-hazard determinations to install the larger new turbines at the site. The Company has also received a Conditional Use Permit and related building permits for the repowering effort from Carbon County, Wyoming.

Q. What is the anticipated construction schedule for Rock River I?

A. For Rock River I, **t**he Company began construction in the summer of 2023, with turbine deliveries and turbine commissioning activities occurring in 2024. The Project is anticipated to be fully online and serving customers in November 2024. Major Project milestones are indicated below:

Milestone	Completion Date
Wyoming CPCN Approval	September 2022
Project Acquisition	February 2023
Construction Mobilization	April 2023
Turbine Foundation Completion	November 2023
	Anticipated Date
Access Road Completion	May 2024
Complete Turbine Deliveries	June 2024
Mechanical and Electrical Completion	August 2024
Turbine Commissioning Completion	December 2024
Final Completion/Site Restoration	July 2025

Q. What is the construction status of Rock River I?

A. Rock River I construction commenced in the summer of 2023 after receiving the Carbon County building permit. The turbine foundations were completed last fall and turbine deliveries will occur in spring 2024, following by turbine installation and commissioning.

Q. What is the forecasted cost of Rock River I?

A. The cost of acquiring and repowering the Rock River I facility is estimated at approximately [redacted] on a total-Company basis, which is equal to approximately [redacted] on an Oregon-allocated basis. However, in this current Oregon general rate case, only calendar year 2024 in-service amounts are included in revenue requirement. Therefore, $99.3 million of the total [redacted] on a total-Company basis and $26.7 million of the [redacted] on an Oregon-allocated basis are included in revenue requirement for recovery in this general rate case. The additional [redacted] total Company and [redacted] Oregon allocated will put into service in 2025. The additional [redacted] includes items such as final project completion scope items, completion of as-built drawings and anticipated punch list items, and site restoration and revegetation.

Q. Does the acquisition and repowering of Rock River I result in customer benefits?

A. Yes. Acquisition and repowering of the Rock River I project will benefit customers, as more fully detailed in the direct testimony of Company witness Thomas R. Burns.

V. REQUALIFICATION FOR PRODUCTION TAX CREDITS

Q. What benefits will customers realize from Rock River I once repowered?

A. Given the extraordinary wind resource in the area, Rock River I will provide significant energy benefits to customers: the Rock River I facility is estimated to provide a very high net capacity factor of [redacted] percent. This net capacity factor will ensure that the facility contributes to system capacity needs.

Q. Will Rock River I qualify for PTCs?

A. Yes. Repowering will requalify the Rock River I facility for PTCs, which will be passed on to the Company's customers.

Q. What is the value of the PTC for Rock River I?

A. For 2023, the value of the federal PTC was 2.8 cents per kilowatt-hour, or $28 per megawatt-hour. This PTC value is adjusted annually based upon an inflation index, and the PTC is available for energy produced during the 10-year period after the wind facility begins commercial operation. Under the Inflation Reduction Act of 2022, Rock River I is expected to qualify for 110 percent of the value of the federal PTC given the location of the facility in Carbon County, which is expected to meet the definition of an "energy community" under the law.

Q. Are there other requirements that Rock River I must satisfy to qualify for the PTC?

A. Yes, the repowered Rock River I facility must be in service before the end of 2025 to meet the Internal Revenue Service continuous efforts safe harbor and qualify for the PTC by completing construction within four calendar years. Repowering at Rock River I will not incorporate retained components from the existing wind turbines at the site. Thus, there are no requirements related to the Internal Revenue Service "80/20" test—a test that was applicable to the repowering of the majority of PacifiCorp's wind fleet in which the foundations and towers were retained.

Q. Will repowering increase the overall generating capacity of Rock River I?

A. No. The existing Rock River I interconnection will be fully used but the generating capacity of Rock River I will not be expanded as a result of repowering. The wind turbine equipment that will be used at Rock River I has been optimized to make full use of the existing interconnection capacity and the Company does not at this time anticipate increasing the interconnection capacity for the facility.

Q. What is the anticipated generation that Rock River I will produce?

A. The Company retained the engineering consulting firm Black & Veatch, Inc. (Black & Veatch) to evaluate the energy production expected from Rock River I. To complete this assessment, Black & Veatch used site wind data, wind turbine location data, operational performance data, and other available site-specific information to model the expected generation from Rock River I. The wind model also evaluated generation losses resulting from the wake losses at each turbine location. Wake losses are the reduction in generation at turbines downwind of other turbines due to reduced wind speed and increased turbulence in the airflow—or wake—behind a turbine. At Rock River I, the estimated annual energy production of the facility is expected to be [redacted] gigawatt-hours after repowering. The technical analysis documenting the expected generation from Rock River I is provided in Confidential Exhibit PAC/1102.

VI. FALL CREEK HATCHERY BACKGROUND AND CURRENT STATUS

Q. Please explain the background of the Fall Creek Hatchery project.

A. The Fall Creek Hatchery project fulfills an obligation of the Company arising out of the KHSA. The KHSA was signed by numerous tribes, governmental agencies, the states of California and Oregon, the Company, and other stakeholders on February 18, 2010, and amended on April 6, 2016, and November 30, 2016. The KHSA resolved the issues surrounding the relicensing of the Klamath Hydroelectric Project (FERC Project. No. P-2082) through the transfer of the Lower Klamath Project developments (J.C. Boyle, Copco No. 1, Copco No. 2, and Iron Gate) to the Klamath River Renewal Corporation (KRRC) and the States of California and Oregon, which are now undertaking their removal. FERC formally split the Klamath Hydroelectric Project into two licenses in March 2018 and in doing so created the Lower Klamath Project (P-14803). In July 2021, FERC issued a license transfer order that, when it became effective, would transfer the license for the Lower Klamath

Project from the Company to the KRRC and the states of California and Oregon as co-licensees. On November 17, 2022, FERC issued a license surrender order for the Lower Klamath Project and on December 1, 2022, the KRRC, California, and Oregon formally accepted that surrender order and the Company transferred the license to the Lower Klamath Project and associated real property to the KRRC, California, and Oregon on the same date. The Company retains ownership of the Fall Creek development including the water rights, diversion works, canals, powerhouse, and the property on which the new hatchery will be constructed. The Company continued to operate the Lower Klamath Project as a contract operator until the last facility ceased operation on January 21, 2024, thus allowing the Company's customers to benefit from the generation from the Lower Klamath Project facilities until they were decommissioned. Removal of the Lower Klamath Facilities began in 2023 with removal of the Copco No. 2 facility, which was completely removed last fall.

The original Fall Creek Hatchery facilities were constructed following the completion of Copco No. 1 Dam in 1918. This hatchery was operated by the California Department of Fish and Wildlife from approximately 1918 to 1948, and then sporadically thereafter. Because of the age of the facility and the lack of routine use, the existing Fall Creek Hatchery was not in suitable condition to meet current fish-rearing or worker safety requirements and was not capable of rearing the number of fish that need to be raised to meet established production goals.

Q. Why is the Company required to build the Fall Creek Hatchery?

A. The KHSA obligated the Company to implement a suite of interim measures to address water quality and aquatic species impacts of the Lower Klamath Project facilities until their removal. One of these, Interim Measure 19, required the Company to develop a plan in consultation with CDFW and NMFS to continue to meet established fish production goals for a period of eight years after the removal of Iron Gate Dam. Implementation includes the development of designs, specification, permits, and construction as necessary to meet mitigation production goals established by CDFW and NMFS. Interim Measure 20 requires the Company to fund hatchery operations and maintenance costs for a period of eight years after removal of Iron Gate Dam.

The KHSA also requires that the Company have the hatchery production continuity measures in place before Iron Gate Dam is removed and the existing water supply to the Iron Gate Hatchery from Iron Gate Reservoir is no longer available. Given the scheduled removal of Iron Gate Dam beginning in January 2024, construction of Fall Creek Hatchery occurred largely in 2023 so that the facility would be operational when needed to continue fish rearing. Completion of Fall Creek Hatchery is scheduled for spring 2024, but the facility is now rearing fish that have been moved to the new facility from Iron Gate Hatchery.

Q. Why was it necessary to build a new hatchery?

A. Iron Gate Hatchery was completed in 1962, concurrent with the completion of Iron Gate Dam, and had been in continuous operation since that time. The cold-water supply to Iron Gate Hatchery was provided by Iron Gate Reservoir through intake structures in the dam itself. With the removal of Iron Gate Dam, which began with reservoir drawdown starting on January 11, 2024, there is no longer a cold-water supply for Iron Gate Hatchery and it is no longer possible to raise Chinook and Coho salmon at that location.

Q. Did the Company consider other means of meeting its hatchery obligations under the KHSA?

A. Yes. The Company, in coordination with the KRRC and CDFW and NMFS, evaluated a suite of alternatives to the Fall Creek Hatchery. Alternatives considered included ways to keep the Iron Gate Hatchery functioning using alternative water supplies, building new facilities to rear fish at different locations, and using other existing hatchery facilities in Oregon and California. The use of Iron Gate Hatchery, with modifications to address the impacted water supply after dam removal, was not feasible because Klamath River water temperatures are too warm in the summer to rear salmon and there are no suitable local surface or groundwater sources that could support the hatchery. Development of hatchery facilities at other locations was also evaluated, but the lack of infrastructure and access at these remote sites made operations, staffing, and security challenging. Other existing hatchery facilities in Oregon and California were investigated but found to be operating at capacity and therefore unavailable to assist in meeting hatchery production goals. Even if capacity were available, using out-of-basin facilities to raise fish would have created biological challenges related to increased straying in returning adults, inter-basin transfer, and potential fish disease issues.

Ultimately, building a new facility at the existing Fall Creek Hatchery site was determined to be the best option. The main reasons for this choice are that there is an adequate volume of water available to support the fish to be raised at the new facility, that water is of high quality, and, because it comes from spring-fed sources, is near optimal temperatures for rearing fish throughout the year. CDFW also has had experience with successfully raising fish at this location. Additionally, the Company continues to own this property, facilitating construction in a timeline that meets the requirements of the KHSA.

Q. Does construction of the Fall Creek Hatchery facility allow the Company to meet its obligations under the KHSA?

A. Yes. Constructing the Fall Creek Hatchery facility will fulfill the Company's obligation under the KHSA to provide funding for implementation of the mitigation plan developed under Interim Measure 19. The fish raised at the Fall Creek Hatchery will help mitigate for fisheries impacts associated with dam removal activities and help provide ongoing fish harvest opportunities for Klamath Basin Tribes as well as commercial and sport fishing stakeholders. The agreed-upon fish production levels will help bolster populations of Coho and Chinook as they recolonize areas upstream of Iron Gate Dam.

Q. Has the project been approved by relevant regulatory agencies?

A. Yes. Plans for the construction of the Fall Creek Hatchery were submitted to FERC for approval and FERC approved the plans and issued an authorization to the Company to proceed with construction on December 21, 2022. Other approvals and permits are in place from the U.S. Army Corps of Engineers, the California State Water Board, CDFW, U.S. Fish and Wildlife, NMFS, and the California State Historic Preservation Officer.

Q. What is the cost of the hatchery?

A. Total cost for the new facility is approximately $36.5 million on a total-Company basis, or approximately $9.8 million on an Oregon-allocated basis. This includes all planning, design, permitting, materials, construction, oversight, and project management costs. This cost does not include operations costs following completion.

Q. Where are operational costs captured?

A. Operational costs for the Fall Creek Hatchery are to be paid by the Company as required by KHSA Interim Measure 20. These operational costs are consistent with those previously expended for the operation of the Iron Gate Hatchery and have been included in the Company's budget as a routine operations and maintenance cost since the KHSA was executed in 2010.

Q. What is the construction status of the project?

A. Following a competitive bid process in 2022, the Company selected a contractor to build the new Fall Creek Hatchery. A construction contract was executed and a limited notice to proceed was issued on August 26, 2022, to allow for the contractor to order long-lead time items (*e.g.*, pre-fabricated buildings) and secure necessary subcontracts. Following receipt of the approval from FERC on December 21, 2022, the Company issued a full notice to proceed on December 28, 2022. The contractor mobilized to the site on January 23, 2023, to begin construction. The hatchery was completed to a degree sufficient to allow it to begin receiving eggs and fish from Iron Gate Hatchery in November 2023 and final completion is expected in March 2024.

Q. How does construction of the facility benefit Oregon customers?

A. Implementation of the KHSA, of which this project is one element, benefits Oregon customers by achieving a fair and balanced outcome related to the relicensing proceeding for the Klamath Hydroelectric Project, and addresses costs, risks, and liabilities associated with ongoing operation of the four dams that are being removed.

Q. Is the Company transferring the hatchery to the Klamath River Renewal Corporation as it did the Lower Klamath Project?

A. No. The Company is not transferring the Fall Creek Hatchery or the property on which the hatchery will be built to the KRRC. The Company will continue to own both the new hatchery and the property for the foreseeable future.

VII. CONCLUSION

Q. Please summarize your testimony.

A. Repowering Rock River I leverages federal PTC benefits to renew not only one of Wyoming's first utility-scale wind plants, but also expands wind operations in one of the most favorable wind energy locations in the Country, while increasing customer benefits and savings.

Construction of the Fall Creek Hatchery supports implementation of the KHSA, and benefits Wyoming customers by achieving a fair and balanced outcome related to the numerous costs, risks, and liabilities associated with ongoing operation and removal of the four dams.

Q. What is your recommendation?

A. I recommend the Commission: (1) find that acquiring and repowering the Rock River I wind project and building the Fall Creek Hatchery are prudent and provide ample customer benefits; and (2) allow the Company to recover the cost of these investments in retail rates.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 433
Exhibit PAC/1101
Witness: Timothy J. Hemstreet

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Timothy J. Hemstreet

Rock River I Site Layout

February 2024

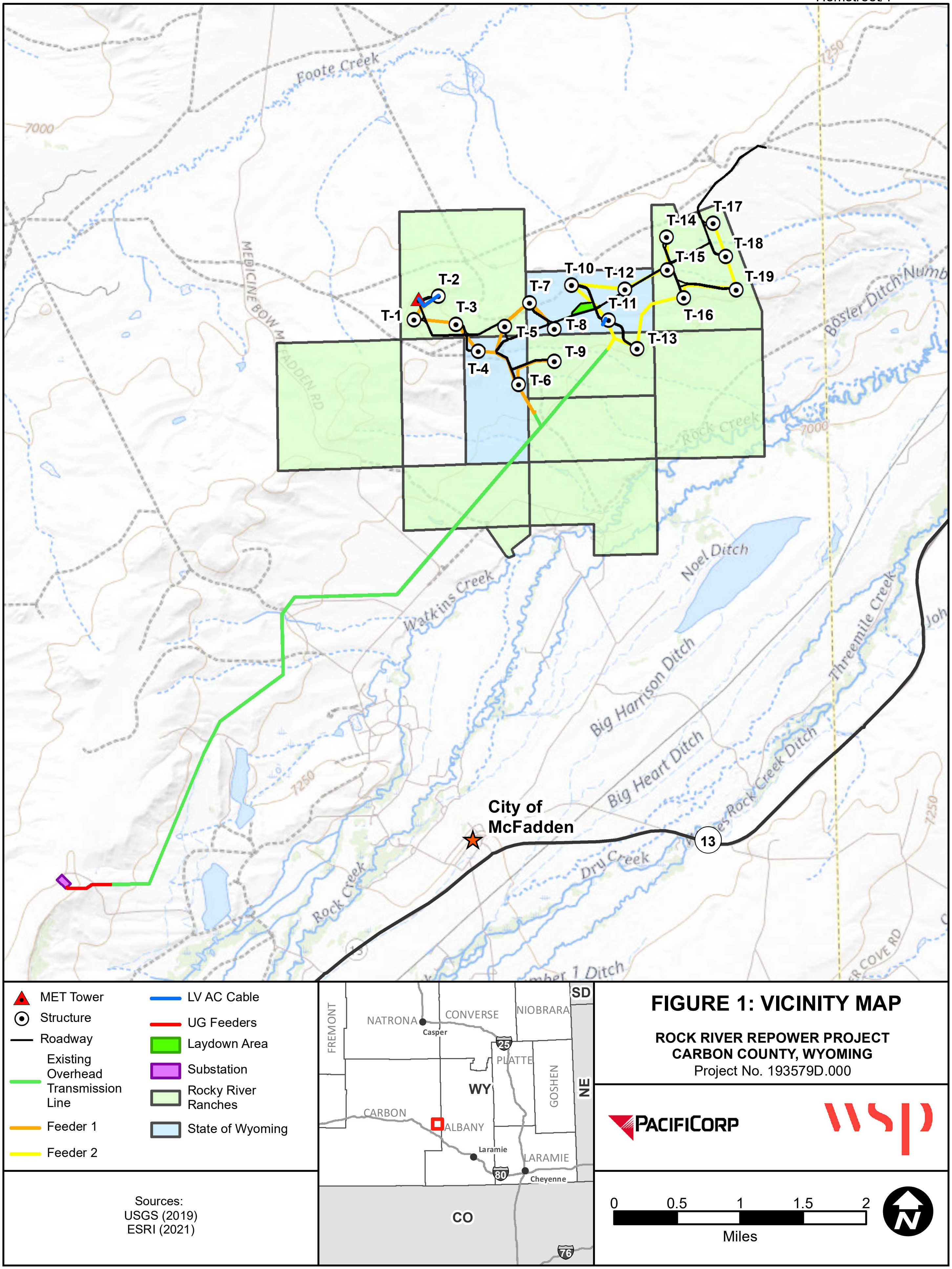


FIGURE 1: VICINITY MAP

ROCK RIVER REPOWER PROJECT
CARBON COUNTY, WYOMING
Project No. 193579D.000

PacifiCorp
wsp

Sources:
USGS (2019)
ESRI (2021)

REDACTED
Docket No. UE 433
Exhibit PAC/1102
Witness: Timothy J. Hemstreet

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Exhibit Accompanying Direct Testimony of Timothy J. Hemstreet

Rock River I Energy Production Analysis

February 2024

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

REDACTED
Docket No. UE 433
Exhibit PAC/1200
Witness: Jeffrey M. Wagner

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Direct Testimony of Jeffrey M. Wagner

February 2024

TABLE OF CONTENTS

ATTACHED EXHIBITS

I. INTRODUCTION AND QUALIFICATIONS

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

A. My name is Jeffrey M. Wagner. My business address is 825 NE Multnomah St., Suite 1800, Portland, Oregon, and I am a Renewable Development Manager.

Q. Please describe your education and professional experience.

A. I have a Bachelor of Science Degree from Walla Walla University and a Master of Business Administration from the University of Wisconsin-Madison. My career in energy began in 2005, including positions at PPM Energy, Eurus Energy, Volkswind and WPD Wind Projects. Prior to joining PacifiCorp in May 2022, I had various roles including project manager, developer and managing director of wind energy development. To date, I have played a key role in developing over 3,000 megawatts (MW) of wind facilities in eight states. In my current role at PacifiCorp as a Renewable Development Manager, my responsibilities encompass strategic planning, regulatory support, stakeholder engagement, and development and execution of major generation resource additions.

II. PURPOSE OF TESTIMONY

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

A. I provide a general description of the Rock Creek I Wind Project (Rock Creek I), an update on development and construction status of the project, and discuss general project costs. The Company is requesting rate recovery for Rock Creek I in this proceeding.

Q. Why did the Company pursue Rock Creek I?

A. As further described in the testimony of Company witness Thomas R. Burns, the Company's 2021 Integrated Resource Plan (IRP) preferred portfolio and 2021 IRP Update both identified a resource need based on a near-term capacity deficit. The Company conducted the 2020 All-Source Request for Proposal (2020AS RFP) to identify cost-effective resources to fill this need. Bids were received from third parties for resources in the form of build-transfer agreements (BTAs), power purchase agreements, and tolling agreements. Rock Creek I was bid by a third-party developer (Invenergy) as a BTA, and this bid was identified among the most economical assets to meet the Company's identified resource need.

III. GENERAL DESCRIPTION

Q. Please describe the Rock Creek I project.

A. Invenergy developed and is constructing two separate facilities—the 190 MW Rock Creek I and 400 MW Rock Creek II facilities. Both resources were selected in the 2020AS RFP. The Company will also procure the Rock Creek II facility from Invenergy, however that facility is planned to reach commercial operation in 2025, beyond the test period for this rate proceeding. My testimony therefore is focused on Rock Creek I and Rock Creek II is not discussed. The Rock Creek I project is located in Carbon and Albany counties, Wyoming and will include (without limitation): wind turbine generators (WTGs) with associated foundations and base pads, electrical collector systems, collector substations, access roads, operations and maintenance buildings, fiber optical and/or microwave communication equipment, supervisory control and operating status data acquisition control systems, main power transformers, meteorological evaluation towers, and overhead transmission tie-lines from the collector substation to the point of interconnection. The point of interconnection will be at the existing Foote Creek substation in Carbon County in southeast Wyoming and will interconnect at 230-kilovolts.

Q. Have preliminary evaluations of the wind potential been performed for Rock Creek I?

A. Yes. Wind resource studies completed for the project indicate that the Rock Creek I site is suitable for high capacity factor wind facilities.[1] Moreover, the site is adjacent to the Company's existing High Plains, McFadden Ridge and Foote Creek Rim wind facilities. Wind data collected from the Company's existing operating wind projects in the area, and the operational history of these projects, demonstrate that the Rock Creek I site has a favorable wind regime suitable for a high performance wind energy facility.

Q. What is the expected operational life of Rock Creek I?

A. Rock Creek I has an anticipated operational life of 30 years, which aligns with the Company's currently approved depreciable life for all of its existing wind resources.

Q. Has the Company received a certificate of public convenience and necessity (CPCN) for Rock Creek I?

A. Yes. The Company filed a CPCN application with the Wyoming Public Service Commission (Wyoming Commission) in August 2022, and the Wyoming

[1] Confidential Exhibit PAC/1201 Energy Yield Assessment for Rock Creek.

Commission approved the application during public deliberations held on February 28, 2023.[2]

IV. DEVELOPMENT AND CONSTRUCTION STATUS

Q. What is the current status of Rock Creek I?

A. Development efforts at Rock Creek I have been completed and the project is now in construction. Invenergy's development efforts included multiple years of wind resource analysis, substantial wildlife and environmental analyses used to design the project and minimize environmental impacts, securing site control through wind energy leases with site property owners, and securing an interconnection agreement with PacifiCorp's transmission function. Invenergy also received conditional use permits in Carbon and Albany Counties and its permit from the Wyoming Department of Environmental Quality, Industrial Siting Division, to support the construction and ongoing operation of the wind facilities. Invenergy is responsible for the final development and construction of the project in accordance with all permitting and technical requirements. As of December 2023, 90 percent of civil construction was complete and all turbine foundations were complete and backfilled. Turbine deliveries are planned to begin in May 2024. Construction remains on track to enable the project to complete testing and commissioning in the fourth quarter of 2024 and to be placed in-service in December 2024.

[2] *In re Rocky Mountain Power Rock Creek CPCN,* Docket No. 20000-623-EN-22, Record No. 17154, Order 29595 (Aug. 9, 2023).

Q. Has PacifiCorp conducted due diligence to confirm the development status of the project?

A. Yes. As part of the 2020AS RFP and throughout the subsequent negotiations with Invenergy, PacifiCorp has conducted due diligence to confirm the on-time development of various items including interconnection status, wind resource performance, production tax credit (PTC) eligibility, site control, permitting status, and conformance to technical specifications. This due diligence informed the Company's negotiations with Invenergy on the scope, schedule, cost, and other terms to establish the BTA.

Q. Has the Company executed a BTA for Rock Creek I?

A. Yes. The Company and Invenergy executed a binding BTA for Rock Creek I on March 24, 2023. The BTA includes provisions for the supply of WTGs for the project, balance of plant construction by a qualified wind energy contractor, and ongoing management of the complete construction of the project. The Company also executed an operations and maintenance agreement with Invenergy which provides for ongoing service and maintenance of the project after it achieves commercial operation.

Q. Please explain the key terms and customer protections of the BTA.

A. Under the BTA, Invenergy is obligated to develop, engineer, procure equipment for, construct, and transfer ownership of Rock Creek I to the Company. The planned in-service date is December 2024. PacifiCorp is obligated to pay a defined purchase price to Invenergy under the BTA. The purchase price is fixed, but can be amended based on certain events. The BTA contains pre- and post-start of construction risk and cost-sharing mechanisms. As Rock Creek I started construction in April 2023, the pre-construction protections served their purpose and Invenergy's construction activities remain on track to achieve the in-service date of December 2024. Examples of cost mitigation protections include:

a. [redacted]

b. [redacted]

c. [redacted]

[redacted]

d. Liquidated Damages: In the event that the project is delayed, Invenergy is required to pay liquidated damages to PacifiCorp.

Q. Who is responsible for construction of Rock Creek I?

A. Invenergy is responsible for construction of Rock Creek I, and is utilizing and managing multiple contractors that are engaged in different aspects of the construction. Invenergy is managing the construction progress with PacifiCorp oversight until construction is complete.

Q. Who will be responsible for supplying WTGs for Rock Creek I?

A. The WTGs will be purchased and delivered according to the terms of a turbine supply agreement which was negotiated and executed by Invenergy. The project is installing WTGs manufactured by [redacted] with a nominal nameplate capacity of [redacted] MW each and rotor diameter of [redacted] meters.

Q. When will construction begin and end?

A. Construction commenced in the second quarter of 2023, with a planned in-service date of December 2024 for Rock Creek I, assuming normal construction circumstances such as weather conditions, labor availability, materials delivery, and permit and agreement processing durations.

Q. How will the Company oversee construction of the project to maintain the proposed in-service date?

A. PacifiCorp's Owner's Engineer oversees construction to ensure the project will be completed on time. This includes reviewing all design submittals to ensure Invenergy meets the technical specification and performance requirements outlined in the BTA, and making periodic site visits to ensure that critical infrastructure is installed per the design documents and has passed acceptability testing.

PacifiCorp also uses full-time on-site inspector(s) to ensure that Invenergy adheres to the project schedule and builds the project consistent with the terms of the BTA. This includes monitoring Invenergy's day-to-day activities, attending daily site meetings, and providing inspection services as needed. PacifiCorp is holding weekly or bi-weekly project status meetings with Invenergy, during which Invenergy reports on the status of the project, discusses critical issues that impact schedule, and addresses the status of any recovery plans as needed.

Q. Who will operate and maintain Rock Creek I?

A. Once construction is complete, Invenergy will provide certain operations and maintenance services for the first five years of operation. During the initial five-year period, the Company will oversee Invenergy to ensure compliance with all relevant agreements and may self-perform any operations and maintenance activities that are not included in the scope of Invenergy's work.

Beginning in the sixth year of operation, the Company expects to assume responsibility for operations and maintenance activities at Rock Creek I. The Company has an experienced team of personnel that are qualified to operate and maintain Rock Creek. The Company currently owns, operates, and maintains an extensive wind generation fleet that includes the High Plains, McFadden Ridge, Foote Creek I, Seven Mile Hill I and II, Ekola Flats, TB Flats I and II, and Dunlap projects in this region of Wyoming, amounting to over 1,240 MW of wind generation. Once construction is complete, the wind turbine supplier will provide a warranty for Rock Creek I for a period of time, during which any significant repairs will be conducted by the wind turbine supplier. In addition, the wind turbine supplier or other third parties may be engaged from time to time to help operate and maintain the project.

Q. Has Invenergy obtained the necessary local permits for the project?

A. Yes. Carbon County issued a Conditional Use Permit for the project on November 16, 2021, and Albany County issued a Conditional Use Permit for the project on January 18, 2022. In addition, the Industrial Siting Council approved Invenergy's application for an Industrial Siting Permit on April 15, 2022. A CPCN was granted to PacifiCorp by the Wyoming Commission on February 28, 2023. Invenergy has also been collaborating with the U.S. Fish and Wildlife Service and the Wyoming Game and Fish Department in developing and implementing the project. Rock Creek I remains on-track for completion and an in-service date of December 2024.[3]

[3] *See, e.g., Carbon County Conditional Use Permit – Resolution No. 2021-41, Wyoming County Clerk, Book 1381, p. 50* (November 16, 2021); *Albany County Conditional Use Permit – WEC-01-21 (January 18, 2022; to be recorded); Wyoming Department of Environmental Quality, Industrial Siting Council - Industrial Siting Permit - Docket No. DEQ/ISC 21-07* (April 15, 2022); *Department of the Air Force, Siting and Mitigation Agreement for Rock Creek Wind Project in Rock River, WY* (February 18, 2021); *Department of Defense, Mitigation Response Team Letter of No Adverse Impact* (February 24, 2021); *Carbon County Road Use Agreement, approved by Carbon County Board of County Commissioners* (November 28, 2022); *Albany County Road Use Agreement, approved by the Albany County Board of County Commissioners* (January 3, 2023); *Wyoming Department of Transportation Road Use Agreement, approved and executed by the Transportation Commission of Wyoming and the Wyoming Department of Transportation Chief Engineer* (January 10, 2023).

V. PROJECT COSTS

Q. What is the estimated capital cost for the project?

A. The estimated capital costs for Rock Creek I is [redacted] Company witness Sherona L. Cheung's direct testimony discusses these costs for Oregon rates in more detail.

Q. How did the Company estimate construction and operations and maintenance (O&M) costs for the project?

A. Project costs are based on negotiations with Invenergy. Interconnection costs were informed by the cost estimates included in the executed Large Generator Interconnection Agreement and interconnection study that informed the interconnection agreement. The Company's costs for engineering, legal, internal project management, and allowance for funds used during construction were estimated based on the Company's experience with development and construction of past wind facilities. O&M cost estimates are based on negotiations with Invenergy and on the Company's experience with wind resource O&M budgets and third-party contracts for the Company's existing wind facilities.

Q. Will Rock Creek I qualify for federal PTCs?

A. Yes. Under the Inflation Reduction Act (IRA), the Company believes that Rock Creek I qualifies for 100 percent of the PTC available for projects placed into service after 2021. For projects placed in service after 2022, the IRA also provides for an additional 10 percent bonus credit if the project is located in an "energy community." This definition includes census tracts, or any directly adjoining census tracts, in which

(1) after 1999 a coal mine has closed, or (2) after 2009 a coal-fired electric generating unit has been retired. With an expected in-service date of 2024 for Rock Creek I the Company expects the project to qualify for a PTC equal to 110 percent of the full credit available. This credit will be returned to customers in the Company's annual Power Cost Adjustment Mechanism filing.

Q. Did the Company assess the customer benefits provided by the project?

A. Yes. Company witness Burns provides a detailed economic analysis of the significant customer benefits that result from the acquisition of Rock Creek I in his testimony.

VI. CONCLUSION

Q. Please summarize your testimony.

A. The Company successfully negotiated a BTA with Invenergy that prudently manages risks, mitigates costs, allows effective oversight, and ensures that Rock Creek I remains on schedule. The project will provide significant benefits to Oregon customers, and I recommend the Public Utility Commission of Oregon approve the inclusion of Rock Creek I in the Company's retail rates.

Q. Does this complete your direct testimony?

A. Yes.

REDACTED
Docket No. UE 433
Exhibit PAC/1201
Witness: Jeffrey M. Wagner

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Exhibit Accompanying Direct Testimony of Jeffrey M. Wagner

Energy Yield Assessment for Rock Creek

February 2024

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

Docket No. UE 433
Exhibit PAC/1202
Witness: Jeffrey M. Wagner

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

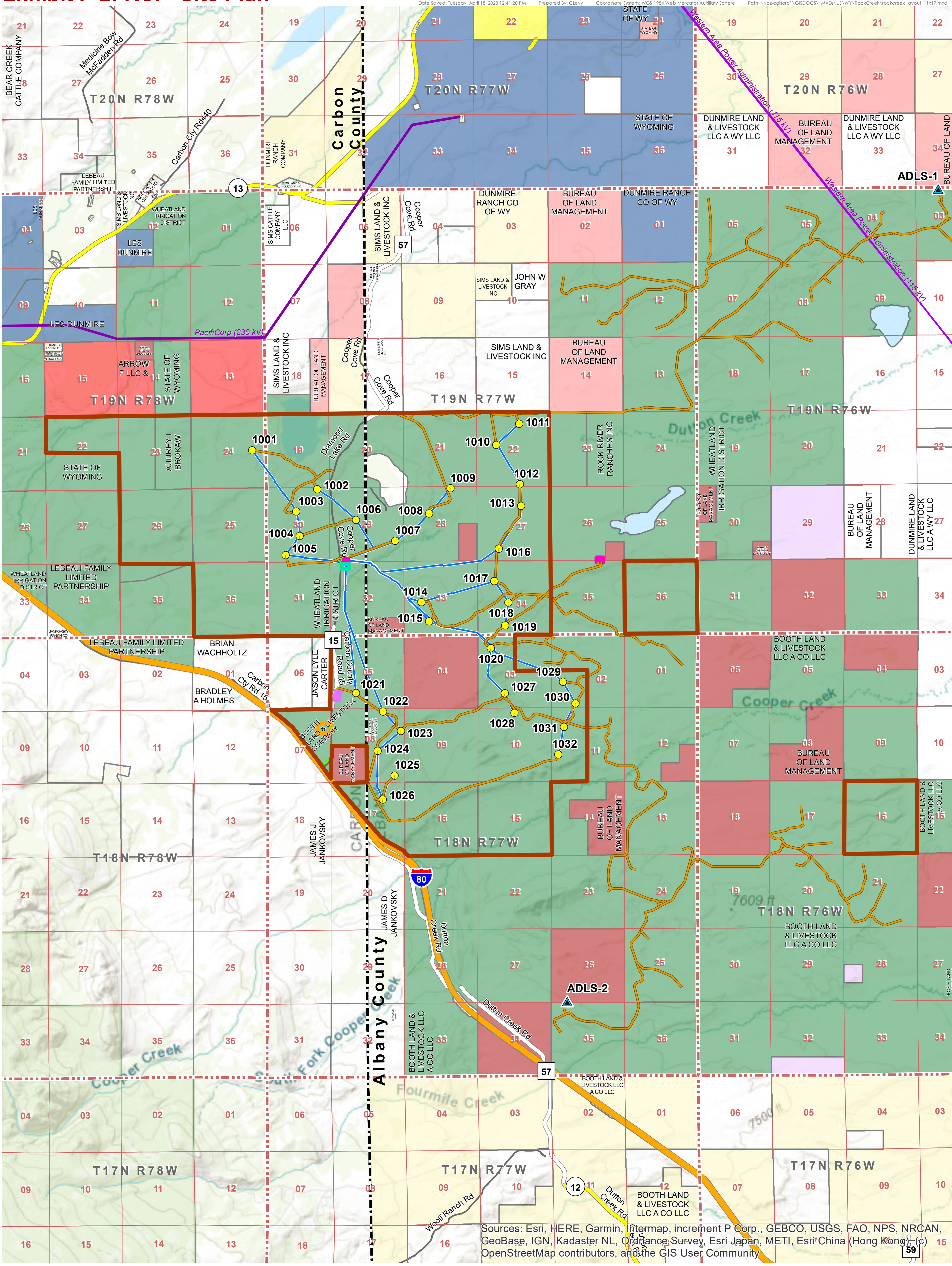
PACIFICORP

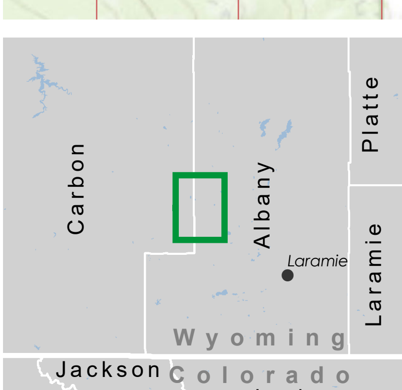
Exhibit Accompanying Direct Testimony of Jeffrey M. Wagner

Site Layout for Rock Creek

February 2024

Exhibit F-2: RCI - Site Plan





Legend

Layout
- Turbine Location
- MET Tower
- Collection
- Access Road
- Laydown Yard
- Marshalling Yard
- O&M Building
- Project Substation
- Temporary Intersection Improvements
- Rock Creek I Project Boundary

Landowner Parcel Status
- Not Participating
- Participating - Wind Agreement
- Participating - Transmission Agreement
- County Boundary

- Township/Range Boundary
- Section Line

Road Classification
- Interstate Highway
- US/State Route
- County Road
- Local Road

Transmission Line
- 100 - 161 kV
- 230 - 300 kV

1 0 1
Miles

RCI - Project Site Plan

SUBJECT TO CHANGE AT SUBSTANTIAL COMPLETION

Rock Creek I Wind Energy Center | Albany & Carbon Counties, Wyoming

April 19, 2023

Invenergy

Docket No. UE 433
Exhibit PAC/1300
Witness: Brad D. Richards

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Brad D. Richards

February 2024

TABLE OF CONTENTS

I. INTRODUCTION AND QUALIFICATIONS

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

A. My name is Brad D. Richards. My business address is 1407 West North Temple, Suite 210, Salt Lake City, Utah 84116. My title is Vice President of Thermal Generation.

Q. Please describe your professional experience.

A. I have 22 years of power plant commissioning, operations, and maintenance experience. I was previously the Managing Director of Gas and Geothermal Generation from January 2018 to September 2021. For 17 years before that, I held a number of positions of increasing responsibility within PacifiCorp's generation organization and with Calpine Corporation in power plant commissioning and operations. In my current role, I am responsible for operating and maintaining PacifiCorp's coal, natural gas-fired, and geothermal generation fleet.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I submitted testimony on behalf of the Company in proceedings before the Utah Public Service Commission and the Washington Utilities and Transportation Commission.

II. PURPOSE OF TESTIMONY

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

A. My testimony provides additional details regarding the natural gas conversion of Jim Bridger Units 1 and 2, the post-conversion operating costs of Jim Bridger Units 1 and 2, and the flue gas desulfurization (FGD) pond project at the Jim Bridger Plant. These capital costs are necessary to continue operating these units and are not life extending capital additions.

III. JIM BRIDGER GAS CONVERSION

Q. Please provide a brief explanation of the process for converting a coal-fired unit to a gas-fired unit at the Jim Bridger facility?

A. The natural gas conversions of Jim Bridger Units 1 and 2 ($34.6 million total-Company, $9.3 million Oregon-allocated) require retrofitting of the boilers with natural gas burners and flame scanners as well as construction of a distribution pipeline which can provide a sufficient supply of natural gas. Certain coal and ash handling equipment will be isolated from the boilers. Additionally, the project requires new filters, gas heaters, pressure regulators, safety valves, high- and low-pressure valves, piping, pipe supports, instrumentation, controls, meters, and other equipment to operate reliably and safely.

Q. Can you provide a brief timeline for when the work will be completed on Jim Bridger Units 1 and 2 to convert these units to natural gas?

A. The timeline is projected to complete both unit conversions and be firing on natural gas by April 30, 2024. Both units came offline on December 31, 2023. Unit 2 will be completed first, immediately followed by Unit 1 in conjunction with the planned Unit 1 overhaul.

Q. Did the Company assess the customer benefits provided by the conversion of Jim Bridger Units 1 and 2 to natural gas?

A. Yes. Company witness Thomas R. Burns explains the economic analysis that was done to support the Company's decision to convert Jim Bridger Units 1 and 2 to natural gas and demonstrates the conversion is in the public interest and will generate benefits for Oregon customers.

Q. How will the natural gas conversion of Jim Bridger Units 1 and 2 affect the variable operating costs of those units?

A. Since fuel costs are handled separately, the variable operating and maintenance (O&M) costs are driven by various chemicals used at the plant, and by ash handling and fly ash sales revenue. By burning natural gas instead of coal, those units will avoid the costs associated with ash handling, as well as certain chemicals used for treating flue gases, scrubber chemicals, mercury, and coal pile sealants. The variable O&M costs are partially offset by fly ash sales, which will be lost upon cessation of coal operations on the units. Other chemicals used for water treatment, various surface cleaning acids, and other miscellaneous chemicals will still be required.

Q. Please explain how the natural gas conversion of Jim Bridger Units 1 and 2 will affect the fixed operating costs of those units.

A. The fixed costs include labor and general maintenance, which will decrease. This change in fixed costs post conversion is primarily driven by the avoidance of both the labor and maintenance related to coal handling functions, this includes the unloading process, and coal pile management, as well as the maintenance on coal crushers, transport equipment, silos, pulverizers, scrubbers, and precipitators. These fixed operating costs are further identified in the testimony of Company witness Sherona L. Cheung.

IV. JIM BRIDGER FLUE GAS DESULFURIZATION POND PROJECT

Q. Please provide a brief overview of the FGD pond project.

A. The FGD Pond #3 project ($41.3 million total-Company, $11.1 million Oregon-allocated), is for the construction of a 4,900 acre-feet double-lined pond. This project was required to comply with the Environmental Protection Agency's coal combustion residuals rule. The rule no longer allows FGD waste to be placed in an unlined pond. The best option for meeting this requirement was to convert the plant's evaporation pond to a lined FGD Pond. The existing unlined FGD Pond #2 stopped receiving FGD wastewater once FGD Pond #3 was operational.

Q. Were these capital costs normal, expected, and necessary to continue to keep the plant in good working order?

A. Yes.

V. CONCLUSION

Q. Please summarize your testimony.

A. My testimony explains the purpose of PacifiCorp's capital investments at the Jim Bridger Plant that are necessary for the continued operation of those units and in the public interest. I recommend that the Public Utility Commission of Oregon approve the inclusion of these costs in Oregon rates as prudent and necessary.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 433
Exhibit PAC/1400
Witness: Allen Berreth

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Allen Berreth

February 2024

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 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 California, Oregon, and 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. While most of these costs are now recovered through the ongoing Wildfire Mitigation Plan (WMP) Automatic Adjustment Clause (AAC), there are certain costs that are not recovered in that mechanism that are recovered in this case. My testimony also supports the baseline vegetation management spend. Additionally, my testimony discusses and supports the inclusion of the restoration costs for the 2020 Labor Day wildfires. Finally, I describe the Company's investment in the Juniper Ridge Bend Service Center. I recommend that the Public Utility Commission of Oregon (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 WMPs.[1]

A. On July 19, 2021, Governor Brown signed SB 762 into law. SB 762 requires that public utilities file with the Commission risk-based WMPs 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.[2] This law allows for recovery of all reasonable costs and prudent investments made by a public utility to implement a WMP and also allows for the recovery of those costs through an automatic adjustment clause.[3] Following SB 762, PacifiCorp filed its first WMP on December 30, 2021.[4]

Q. What are the elements of the WMP?

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

[1] Per formal rulemaking and OAR 860-300-0020, the Wildfire Protection Plan is now referred to as the Wildfire Mitigation Plan.
[2] *See* ORS 757.963.
[3] ORS 757.963(8).
[4] *See* UM 2207. Since 2021 the Company has filed a WMP annually with the most recent WMP filed on December 29, 2023.

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.

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.

IV. WILDFIRE MITIGATION CAPITAL COSTS

Q. Please explain how the Company recovers costs for the implementation of the WMP.

A. The majority of costs for the implementation of PacifiCorp's WMP are recovered through the WMP AAC.

Q. Please explain the WMP AAC that was approved by the Commission in docket UE 407.[5]

A. The Company makes an annual advice filing adjusting Schedule 190 rates to reflect collection for the Company's WMP Oregon capital investments, projections of WMP incremental costs for the coming year, as well as incorporating any variances from the previous year. The forecast WMP expense for the next calendar year is based on the annual WMP. The residual amounts in the balancing account may result in an increase or a decrease in the amounts to be collected through the adjustment schedule. The combined forecast amounts, capital investments plus residual balance amount, is the total amount to be collected through Schedule 190 rates for the year.

Q. Are there certain costs associated with the WMP that are not recovered through the WMP AAC?

A. Yes. Consistent with the agreement with staff reached in Advice No. 23-015 (ADV 1529) and approved by the Commission on January 9, 2024, capital costs associated with wildfire mitigation activities for transmission lines located outside the state of Oregon and certain costs related to indirect capital loadings were removed from the WMP AAC and will be recovered in this proceeding. While Company witness Sherona L. Cheung will address how wildfire mitigation capital costs, including capital loadings, are reflected in this case in her testimony, I describe the transmission investments outside of Oregon in greater detail below.

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[5] *In the Matter of PacifiCorp, dba Pacific Power, Application for Approval of an Automatic Adjustment Clause for Recovery of Costs Associated with the Company's Wildfire Protection Plan;* Docket No. UE 407, Order 23-173 (May 10, 2023).

Q. Please identify the amount of capital investment the Company is seeking to recover for wildfire mitigation investments in transmission lines outside the state of Oregon.

A. The Company is seeking to recover $14.9 million of project costs on an Oregon-allocated basis.

Q. Can you provide a brief explanation of the types of investments that are included in this amount?

A. Yes, these investments represent rebuilding transmission lines with the installation of new equipment such as poles, insulators, and conductor. Rebuilding transmission lines in areas where the wildfire risk is heightened allows PacifiCorp to improve structures which will reduce the probability of a fault event and improve resiliency to the extent rebuilt structures can better withstand wildfire events.

Q. Do these investments benefit PacifiCorp's Oregon customers and help reduce wildfire risk across PacifiCorp's system?

A. Yes, 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 the risk of ignition sources is heightened. Maintaining a resilient transmission system benefits all states that PacifiCorp serves as it allows power to be moved from the location of generation to the communities served.

V. VEGETATION MANAGEMENT

Q. Is PacifiCorp proposing an increase in baseline vegetation management costs?

A. Yes. 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. Is there an incremental impact of these 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 $50 million to $67 million.

Q. What steps did the Company take to control costs while still achieving the goals of the program from the last general rate case?

A. PacifiCorp implemented two strategies for cost control and delivering on the goals of the vegetation management program as described above. The first strategy was to increase the number of internal Company foresters that coordinate the vegetation management activity within a geographic area. This increased oversight of both program efficiencies and deliverables. The second strategy was to implement an internal vegetation management audit team to bolster the quality assurance reviews of the program. This helped drive program performance in terms of productivity, efficiency, and cost of program deliverables.

Q. Has PacifiCorp seen improvement in outcomes for the Company's vegetation management programs?

A. Yes, through increased vegetation management activities and quality control audits of the vegetation management program through forester interaction and oversight of contractors the number of internal audit findings resolved has increased resulting in a decrease of the number of probable violations identified in the Oregon Public Commission annual audit.

Q. Is PacifiCorp proposing to continue the Wildfire Mitigation and Vegetation Management (WMVM) adjustment mechanism?

A. Yes. In Order No. 22-491 the Commission approved the current structure of the WMVM. PacifiCorp proposes to continue the use of this mechanism until its next general rate case.

VI. 2020 WILDFIRE RESTORATION COSTS

Q. Can you please describe the 2020 wildfires?

A. At the beginning of September 2020, a historic wind event resulted in a number of wildfires spreading across Oregon causing widespread and extensive damage in and around PacifiCorp's service territory. Areas affected by the fires include western Oregon counties where the Company provides service including Josephine, Jackson, Douglas, Lane, Linn, Lincoln, Klamath, and Marion Counties. This event resulted in widespread and extensive damage to PacifiCorp's transmission and distribution facilities and resulted in loss of power to customers.

Q. Can you describe the restoration activities that occurred as a result of these activities?

A. Yes, PacifiCorp coordinated with state and local officials to gain access and repair damaged structures to restore service to its customers in those areas affected. PacifiCorp incurred significant costs restoring power to customers and repairing, restoring, and replacing damaged equipment. The areas affected had extensive damage to transmission and distribution lines that required immediate reconstruction of burnt poles and replacement of conductors to restore vital electric service to communities in PacifiCorp's service territory. Over 500 field resources were deployed to work with public safety partners responding to the containment and reconstruction and restoration of communities.

Q. Can you describe the restoration and rebuild efforts that have occurred?

A. Yes, the following table provides a high-level summary of the restoration along with the benefits and resiliency efforts:

District	Wildfire	Benefits
Medford	Almeda	Restore services to customers in Talent, Phoenix, Ashland, and Medford and address distribution tree removal.
Medford	South Obenchain	Restore transmission Line 19 for Prospect Hydro, and to customers in Shady Cove and Butte Falls. Address transmission rights of way vegetation and distribution tree removal.
Lincoln City	Echo Mountain	Restore transmission redundancy on Van Duzer transmission lines, address vegetation management along transmission right of way and restore customers in Otis and Neotsu, and address distribution tree removal.
Roseburg	Archie Creek	Restore Line 46 and Line 39 transmission in support of Umpqua hydro projects, address long-term vegetation management and tree removal for both rebuild and future asset protection, procure fire wrapped poles for Line 39, access management and erosion control for improved access. Restore distribution service to customers in the town of Glide.
Stayton	Beachie Creek	Restore customers on the distribution system in Mehama, Mill City, Gates, and Lyons. Address vegetation removal in support of rebuild efforts.
Grants Pass	Slater	Restore transmission on Line 33. Restore distribution service to customers in Takelma and O'Brien.
Klamath Falls	Two Four Two Fire	Restore distribution service to customers in Chiloquin and address vegetation along both distribution and transmission right of way.

Q. Is there work continuing in support of these activities?

A. Yes, of the work noted in the table above, environmental cultural studies and reporting in support of vegetation management and line rebuild efforts remains for the Archie Creek Fire. Ongoing service restoration will continue in all rebuild project locations as customers continue to rebuild homes and businesses that were destroyed. This work is anticipated to continue through 2024.

Q. What were the costs of these activities?

A. The costs of these activities have been deferred as identified in docket UM 2116,[6] and the Company is seeking to amortize the approximately $45.2 million in costs, before interest accrual, that have been incurred through 2023.

Q. Please explain why it is prudent and in the public interest for PacifiCorp to recover these costs.

A. The Company has an obligation to serve its customers and these activities were necessary and reasonable to eliminate potentially hazardous conditions, repair or replace damaged facilities, and restore service to customers in the affected areas.

VII. JUNIPER RIDGE BEND SERVICE CENTER

Q. Please describe the Company's new Juniper Ridge Bend Service Center.

A. The new Bend Service center includes office space, truck bays, warehouse, meter/wireroom, mechanic shop, yard storage, parking, and conference/learning space on 15 acres. The service center will be used primarily by the Company field employees that provide operational support (maintenance, operations, construction of the transmission, substation, and distribution electrical network) to the surrounding communities.

[6] *In the Matter of PacifiCorp, dba Pacific Power, Application Deferred Accounting Related to Wildfire Damage and Restoration Costs,* Docket No. UM 2116, Order Nos. 22-154 (May 9, 2022) and 22-140 (May 9, 2022).

Q. Please explain why the new Juniper Ridge Bend Service Center is necessary for the Company to provide service to Oregon customers.

A. This new site will consolidate the three Bend-area operating centers (the leased Bend Service Center and Bend Metering Office, and the owned Bend Substation Ops) into one location and resolve end-of-lease risks for the current Bend Service Center and Bend Metering Office.

Q. Will the Company's new Juniper Ridge Bend Service Center lead to greater efficiency in the Company's operations?

A. Yes. The consolidated operational center creates increased collaboration, facility efficiencies (e.g., building maintenance, consolidated storage, etc.) and makes use of the previously unused Company-owned Juniper Ridge property. Consolidating multiple leased facilities into one Company-owned location reduces annual rent expense and eliminates future lease increase exposure.

Q. What is the forecast cost of the Juniper Ridge Bend Service Center and when is it expected to be placed in-service?

A. The total project is forecasted to be $40.3 million, and is expected to be in-service by December 2024.

VII. CONCLUSION

Q. Please summarize your recommendation to the Commission.

A. My testimony supports the Company's activities with regards to Wildfire Mitigation costs that are not included in the WMP AAC and the current level of appropriate non-wildfire vegetation management spend. Additionally, I support the prudence of the costs associated with the Company's restoration of power and additional capital investments from the 2020 wildfires. Finally, I support the Company's investment in the new Juniper Ridge Bend service center. I recommend the Commission approve these investments as prudent and appropriate for inclusion for recovery in this general rate proceeding.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 433
Exhibit PAC/1500
Witness: William J. Comeau

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of William J. Comeau

February 2024

TABLE OF CONTENTS

I. INTRODUCTION AND QUALIFICATIONS

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

A. My name is William J. Comeau. My business address is 1407 West North Temple, Suite 310, Salt Lake City, Utah, 84116. I am the Vice President of Customer Experience and Innovation for PacifiCorp.

Q. Please describe your education and professional experience.

A. I have a Bachelor of Science from Weber State University and a Master of Business Administration from Keller University. During my 22 years of working in the utility industry I have held multiple responsibilities including roles in economic development, customer service, demand side management programs and renewable energy, and since January 2020, I have served as Vice President of Customer Experience and Innovation. Through that role I oversee PacifiCorp's call centers, customer billing, customer technology tools (*e.g.*, customer web account and mobile app) and customer programs.

Q. Have you testified in previous regulatory proceedings?

Yes. I have previously sponsored testimony in Washington, Wyoming and Utah.

II. PURPOSE OF TESTIMONY

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

A. I provide background on, and the need to upgrade, the Company's legacy Customer Service System (CSS).

III. PACIFICORP'S CURRENT CUSTOMER SERVICE SYSTEM

Q. Can you please provide background on the Company's current system?

A. Yes. PacifiCorp's existing CSS was placed in service in the 1990's. The initial CSS utilized IBM mainframe technologies and provided an integrated solution for the Company's customer service needs, but the system was limited to supporting billing and customer care functions. The CSS currently supports, in various functions and capabilities, the Company's billing and relationship management of two million customers across its six-state service territories.

Q. Has PacifiCorp expanded CSS capabilities over time?

A. Yes. Over time, the Company enhanced the core CSS products to meet evolving customer and regulatory expectations. In 2001, the Company added the Customer Relationship Management function to better integrate customer contact management. Starting in 2005, PacifiCorp integrated the Mobile Workforce Management function to improve field service coordination for customer requested work orders, and better track net metering and customer generation data collection and billing compatibilities. In 2018, the Company expanded the CSS to address web and mobile apps for customers to manage their accounts, pay bills, and report outages. Also in 2018, PacifiCorp added customer preferences and notification support to provide customer communication channel preferences.

Q. Are there limits to the existing CSS?

A. Yes. Due to the age of the current CSS system and the need to meet evolving customer expectations, CSS has reached its limits for performance, stability, security, upgrades, and technical support. The current hardware and software prohibit flexibility, integration, and forward adoption of new technologies. The IBM mainframes were invented and built to serve information technology (IT) needs in a pre-cellular phone and pre-widespread adoption of the internet business climate. Fast forward several decades, and the mainframes have limited ability to incorporate modern services, advanced rate structures, or technologies. Focusing on interval meter data specifically, CSS lacks the ability to store and process large amounts of interval data.

Q. Are there other limits to the existing CSS?

A. Yes. First, I am concerned about the Company's ability to maintain the existing CSS given the shifting marketplace over the last decade from hardware and software physically located on the user's premise, to cloud or remote-based software and hardware. While my primary responsibility at the Company is customer service, not hiring IT professionals, I am aware that this shift means IT professionals will have skill sets that align with the current state of the industry, not mainframe software from the 1990's.

Finally, on limited occasions CSS became unresponsive due to high workloads and constraints of resources in the mainframe resulting from events, when they happen at the same time, such as large outages or higher call volume. This is of particular concern as the demands from customers for more access to information are increasing.

Q. Are there any other details you would like to provide about the Company's CSS?

A. Yes. While CSS has been a durable and hard-working system for the last several decades, it is time to replace and modernize the Company's IT system. The current system has mainframe capacity issues, requires unnecessary complexity in managing system interfaces, is beginning to experience performance problems, and often creates challenges to align support, patches, and enhancements across multiple vendors.

IV. DECISION TO UPDATE THE CURRENT CSS

Q. What lead the Company to decide to update its CSS?

A. The Company concluded that it was time to replace and update its CSS hardware and software for the reasons discussed above. The new CSS will be a modern system to replace existing functionality and provide the foundation to continually add new functionality to improve the customer experience over the life of the system.

Q. How did the Company select a vendor?

A. PacifiCorp has several software systems that are reaching the end of their operational lives. Technological advancements and functionality needs are outpacing its ability to update outdated systems. As PacifiCorp was contemplating software system improvement plans, its parent company, Berkshire Hathaway Energy (BHE), determined that it could improve efficiencies across platforms by looking to standardize certain systems. PacifiCorp compared participation in the BHE effort versus stand-alone replacement and determined that participation in common enterprise systems was a prudent decision that will continue to improve PacifiCorp's cybersecurity protections, leverage aggregation to cost-effectively replace existing IT infrastructure that is reaching the end of its anticipated useful life, align systems and processes to create increased collaboration and flexibility of resources, meet customer expectations, and improve the customer experience over time.

Q. What is the overall cost of the CSS update?

A. The forecast project cost for implementation of the updated customer information system is approximately $154.7 million on a total-Company basis, which translates to approximately $42.4 million on an Oregon-allocated basis.

Q. How will the new system improve the Company's CSS and benefit customers over time?

A. The new CSS system will be based on current technology platforms and include the necessary functionality to effectively provide the service the Company's customers expect. Example of short- and long-term benefits include:

- Improved customer experience by streamlining processes and systems;
- Ability to continually improve system functions, such as rate schedule billing, by configuration as opposed to more expensive customizations under the current CSS;
- Enhanced customer service processes that provide more accurate and timely resolution of customer service requests;
- Ability to assist customers with guided actions based on analytical customer data;
- Provide customers and employees with the capability to interact using the communication device of the customer's choice (text, email, phone, mail). All engagement channels will feel seamless when migrating from one to the other, avoiding lost data or confusion for the customer;
- Include communication strategies integrated within solutions, minimizing manual intervention, and real-time assignment of work to increase efficiencies for employees and expedite successful outcomes for customers;
- Customers can choose to customize usage alerts through their choice of text, email, or phone when their energy usage may move them into a higher and more expensive tier;
- Updates outdated mainframe interfaces used by customer service agents to improve efficiency including faster insights to better serve customers and interact with field personnel;

- Addresses inflexibility issues in current systems that requires expensive and time-consuming custom changes;
- Addresses capacity and performance issues within the existing CSS ensuring system availability during high usage times (customer outages and events);
- Configurable systems to decrease the time and cost required to implement future customer and regulatory requirements; and
- Addresses manual complex billing issues, because complex bills (such as coincidental peak demand across multiple meters) cannot be calculated currently in CSS and are manually calculated—a labor intensive process that has the potential for human error.

Q. What is the projected in-service date for the CSS replacement?

A. The CSS replacement is currently projected to be in service in September 2024, though improvements and enhancements for efficiency and improved customer experience will continue after the initial in-service date.

V. CONCLUSION

Q. Please summarize your testimony.

A. Updating the Company's CSS replaces an outdated system with current technology that will enable modern solutions to customer services support, customer correspondence, billing and settlement services, and customer relationship management, along with a foundation to efficiently assimilate new technologies and continually improve the customer experience. I recommend that the Public Utility Commission of Oregon include these costs in rates as prudent.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 433
Exhibit PAC/1600
Witness: Kenneth Lee Elder, Jr.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Kenneth Lee Elder, Jr.

February 2024

TABLE OF CONTENTS

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, business address, and current 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. Please 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, load research and customer benefit indicator development. 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 Oregon, Utah, Washington, and Wyoming.

II. PURPOSE OF TESTIMONY

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

A. I provide testimony related to the Company's sales and load forecast.

III. SALES AND LOAD FORECAST

Q. Please summarize your testimony on PacifiCorp's sales and load forecast.

A. I provide PacifiCorp's 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, 2025. PacifiCorp's load forecast has been updated with the most recent information available and includes certain changes in methodology to more accurately forecast load.

Q. When did PacifiCorp prepare the sales and load forecast used in this filing?

A. The sales and load forecast used in this filing was completed in May 2023. The May 2023 sales and load forecast is the most recent forecast of sales and loads prepared by the Company.

Q. What is the difference between sales and load?

A. Sales are measured at the customer meter, while load is measured at the generator or system input level.

Q. How did the Company use the May 2023 sales and load forecast in its preparation of this general rate case (Rate Case)?

A. The May 2023 load forecast was used by Company witness Ms. Sherona L. Cheung to calculate the inter-jurisdictional allocation factors. The sales forecast by rate schedule was used by Company witness Mr. Robert M. Meredith to allocate costs between customer classes and to design rates that correctly reflect the cost of service.

Q. Please provide a general overview of PacifiCorp's sales and load forecast methodology.

A. PacifiCorp first develops 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.

Q. Please provide a summary of the forecast energy sales for 2025.

A. Table 1 provides the forecasted energy sales in megawatt-hours (MWh) for the 12-month period ending December 31, 2025 (Test Period).

Table 1. Test Period Sales Forecast (MWh)

2025 Rate Case (CY 2025)		
Customer Class	**Total-Company**	**Oregon**
Residential	18,229,909	5,936,359
Commercial	23,791,222	7,986,695
Industrial	18,467,000	1,467,541
Irrigation	1,464,877	254,046
Lighting	98,916	30,286
Total	62,051,923	15,674,929

Q. How does the total-Company sales forecast for 2025 compare to the sales forecast used in the 2023 Rate Case[1]?

A. As shown in Table 2, total-Company 2025 forecast sales are 7.5 percent higher than 2023 forecast sales used in the 2023 Rate Case. The difference in the forecasts is attributable to an increase in commercial and residential sales. The growth in the commercial class is related to data center growth, while residential load is increasing due to a higher customer forecast and an increase in air-conditioning loads. The industrial class decrease is attributable to lower projected sales in Utah, Idaho, and Washington.

[1] *In the Matters of PacifiCorp, dba Pacific Power, Request for a General Rate Revision,* Docket Nos. UE 399, UM 1964, UM 2134, UM 2142, UM 2167, UM 2185, UM 2186, and UM 2201 (cons.), Order No. 22-491 at 3 (Dec. 16, 2022).

Table 2. Total-Company Sales Comparison (MWh)

Customer Class	Previous Rate Case CY 2023	Current Rate Case CY 2025	Percentage Difference
Residential	17,109,240	18,229,909	6.6%
Commercial	20,419,167	23,791,222	16.5%
Industrial	18,619,291	18,467,000	-0.8%
Irrigation	1,475,938	1,464,877	-0.7%
Lighting	100,089	98,916	-1.2%
Total	57,723,723	62,051,923	7.5%

Q. How does the Oregon sales forecast for 2025 compare to the sales forecast for the 2023 Rate Case?

A. As shown in Table 3, the 2025 Oregon sales forecast has increased by 12.5 percent from the 2023 sales forecast used in the 2023 Rate Case. In Oregon, the residential class forecast is higher due to a higher customer forecast and an increase in air-conditioning loads. The commercial class increase in the forecast is attributable to data center growth expectations. The irrigation class forecast is lower due to the reclassification of a large customer, while the lighting class is lower due to light-emitting diode (LED) adoption.

Table 3. Oregon Sales Comparison (MWh)

Customer Class	Previous Rate Case CY 2023	Current Rate Case CY 2025	Percentage Difference
Residential	5,780,833	5,936,359	2.7%
Commercial	6,321,549	7,986,695	26.3%
Industrial	1,465,509	1,467,541	0.1%
Irrigation	333,716	254,046	-23.9%
Lighting	35,996	30,286	-15.9%
Total	13,937,602	15,674,929	12.5%

Q. Please summarize the major updates used to produce this forecast as compared to the forecast used in the 2023 Rate Case.

A. The Company updated many of its data inputs when compared to the forecast prepared for the 2023 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 2006 through February 2023. The historical data period used to develop the industrial monthly sales is from January 2008 through February 2023. The irrigation class uses the historical data period of January 2006 through February 2023, while the lighting class uses the historical data period of April 2006 through February 2023.
2. The Company updated the historical data period used to develop the monthly peak forecasts to include January 2008 through December 2022.
3. The Company updated the economic drivers for each of the Company's jurisdictions using IHS Markit data released in March 2023.
4. The Company updated the forecast of individual industrial and commercial customer usage based on the best information available as of April 2023.
5. The time period used to calculate normal weather was defined as the 20-year time period of 2003 through 2022.
6. The Company used the climate change impact estimate from the March 2021 United States Bureau of Reclamation to adjust the normal weather for

expected climate change impacts.[2]

7. The Company rolled forward the line loss calculation to the five-year period ending December 2022.
8. The data used to develop temperature splines was rolled forward based on available customer class hourly data (October 2017 through September 2022).
9. The Company used the residential use-per-customer model with appliance saturation and efficiency results released in October 2022.

Q. Are there any changes in the load forecast methodology since the 2023 Rate Case?

A. Yes. The changes in methodology include:

The Company has adopted climate change impacts to normal weather, updated the timeframe used for developing the jurisdictional hourly load shapes as well as the timeframe used to develop the chaotic normal weather pattern relied on in the forecast.

- In order to capture climate change impacts on the load forecast, the Company has adopted the climate change adjustment to normal weather. The climate change weather uses the data from the historical period (2003 through 2022) and adjusts the percentile of the data to achieve the expected target average annual temperature and calculate the heating degree days and cooling degree days impacts and peak producing weather impacts within the energy forecast and peak forecast, respectively. This is the same methodology adopted in the Company's 2023 Integrated Resource Plan.

- In order to capture the most recent hourly weather trends, the May 2023 forecast used the most recent five years of actuals, 2018 through 2022, to develop jurisdictional hourly shapes over the forecast horizon.

[2] United States Bureau of Reclamation, March 2021, Managing Water in the West, Technical Memorandum No. ENV-2021-001, West-Wide Climate Risk Assessments: Hydroclimate Projections. https://www.usbr.gov/climate/secure/docs/2021secure/westwidesecurereport1-2.pdf

- The weather pattern used to capture a normal amount of variability in daily weather across the Company's six state service territory was updated based on the period of 2013 to 2020.

- The Company updated its peak models to remove base load from the historical peaks before model input and only modeled the incremental load above base load. The final peak forecast is the forecasted base load plus the peak adder calculated from the peak model.

A. <u>Monthly Sales Forecast Methodology</u>

Q. How are the forecasts for number of customers developed?

A. For the residential class, PacifiCorp forecasts the number of customers using IHS Markit's forecast of number of households or population as the major driver. For the commercial class, PacifiCorp forecasts the number of customers using households, population or residential customer forecast as the major economic driver. For the industrial, irrigation and street lighting classes, the customer forecasts are fairly static and developed using time series or regression models without any economic drivers.

Q. What methodology does PacifiCorp use to forecast the residential class sales?

A. PacifiCorp 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. PacifiCorp models sales-per-customer for the residential class through a Statistically Adjusted End-Use model, which combines the end-use modeling concepts with traditional regression analysis techniques.

Q. What methodology does the Company use to forecast the commercial class sales?

A. For the commercial class, PacifiCorp 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 PacifiCorp forecasts its largest industrial customers, large commercial customers such as data centers are based on input from the Company's regional business managers (RBMs).

Q. How does PacifiCorp forecast sales for the industrial customer class?

A. The majority of industrial customers are modeled using regression analysis with trend and economic variables. Manufacturing employment is used as the major economic driver. For a small number of industrial customers (the largest on the system), PacifiCorp individually prepares forecasts based on input from the customer and the RBMs.

Q. What methodology does PacifiCorp use for the irrigation and lighting sales forecasts?

A. For the irrigation class, PacifiCorp 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 LED lighting adoption curve.

B. <u>Hourly Load Forecast</u>

Q. Please outline how the hourly load forecast is developed.

A. After PacifiCorp 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. This forecast is based on average monthly historical peak-producing weather for January 2003 through December 2022.

Second, hourly load forecasts are developed 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.

C. <u>Forecasts by Rate Schedule</u>

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. PacifiCorp develops this forecast in two steps: (1) it forecasts test year sales by rate schedule; and (2) it proportionally adjusts the rate schedule sales forecasts so that the total matches the customer class forecast.

Q. Finally, how does PacifiCorp 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, PacifiCorp forecasts the number of bills by class and by rate schedule. Then, PacifiCorp proportionally adjusts the forecasted number of bills by rate schedule so that the total number of bills matches the customer class forecasted number of bills.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 433
Exhibit PAC/1700
Witness: Sherona L. Cheung

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Sherona L. Cheung

February 2024

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 Sherona L. Cheung, and my business address is 825 NE Multnomah Street, Suite 2000, Portland, Oregon 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 Oregon, Washington, 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, Oregon, 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 $157.7 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 $1,234.2 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 2023 (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, 2025 (Test Period).
- The treatment of forecast capital additions included in the revenue requirement calculations, which have been limited to projects placed in service before January 1, 2025, 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 6.5 percent, which is less than the Company's currently authorized ROE of 9.5 percent and the 10.3 percent requested by the Company and supported by Company witness Ann E. Bulkley in this proceeding.
- An overview of the implementation of two new rate schedules dedicated to the recovery of excess liability insurance premiums (both deferred and on-going), and the funding of a Catastrophic Fire Fund, as well as changes to the Wildfire Mitigation Plan (WMP) Automatic Adjustment Clause (AAC) schedule, and the COVID-19 costs deferral amortization schedule.

Q. How have you organized your testimony?

A. I have divided my testimony into four 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/1702. In Section VI, I provide a description of modifications to rate schedules that the Company is seeking beyond its base rate price change in this case, specifically with regards to the creation of two new rate schedules for the recovery of excess liability insurance premiums, and the funding of a Catastrophic Fire Fund, as well as requested changes to the WMP AAC schedule and the COVID-19 costs deferral amortization schedule.

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 6.5 percent during the Test Period. This return is less than the 9.5 percent ROE authorized in the Company's 2023 GRC, docket UE 399 (2023 Rate Case).[1] The Company is proposing to change the authorized ROE in this case to 10.3 percent. A 10.3 percent ROE produces a non-NPC revenue requirement of $1,234.2 million based on the 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol (2020 Protocol). Exhibit PAC/1701 provides a summary of the Company's Oregon-allocated results of operations for the Test Period. Exhibit PAC/1702 provides the supporting details and calculations and is discussed in greater detail later in my testimony.

[1] *In the Matter of PacifiCorp, d/b/a Pacific Power, Request for a General Rate Revision*, Docket No. UE 399, Order No. 22-491 at 7 (Dec. 16, 2022). The Commission set an overall rate of return at 7.109 percent and an authorized return on equity of 9.5 percent.

Q. Please explain how you have treated NPC in this filing.

A. As noted above, the Company recovers its NPC through the TAM, which is being concurrently filed with this GRC,[2] for calendar year 2025 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 GRC are provided in Exhibit PAC/1701. Page 1.0 of Exhibit PAC/1701 also shows the division of revenue requirement between the TAM and GRC components, and the resulting GRC-related price change requested in this case.

A. <u>Base Period</u>

Q. Why did the Company use July 2022 through June 2023 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 2023 as the historical basis for this case because it was the most recent total-Company data available for inter-jurisdictional allocations to achieve its targeted filing date for the current proceeding. 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

[2] *In re the matter of PacifiCorp dba Pacific Power 2025 Transition Adjustment Mechanism,* Docket No. UE 434, Initial Filing (Feb. 14, 2024).

review procedure is a key control measure to ensure the accuracy and reliability of the data, which serves as the basis for each of the Company's results of operations and GRC filings.

Q. When will calendar year 2023 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 2023 data will not be available for use as the basis of a forecast test period until the end of April 2024, more than two months after this GRC is filed.

B. <u>Test Period</u>

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, 2025.

Q. Why did the Company choose the year ending December 31, 2025, 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, 2025, which matches the start of the Test Period used by the Company in the calculation of the revenue requirement. The Test Period in this GRC 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, 2023. 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 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 Incremental O&M Expenses adjustment (Exhibit PAC/1702, adjustment page 4.13). 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 GRC?

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 GRC, 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. No. This filing reflects Test Period depreciation expense in the Company's revenue requirement that is calculated generally based on depreciation rates approved in the 2018 Depreciation Study.[3] Additionally, the Company has reflected approved incremental depreciation expenses for Colstrip Units 3 and 4, Craig Unit 2, and Hayden Units 1 and 2 as well as Jim Bridger Units 1 and 2 in accordance with the approved revision to the end of depreciable lives for these units as adopted in the settlement and approved in the final order of the Company's previous GRC, docket UE 399.[4]

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, 2024, rather than through the end of the forecast Test Period and the rate effective

[3] *In the Matter of PacifiCorp dba Pacific Power Application for Authority to Implement Revised Depreciation Rates,* Docket No. UM 1968, Application (Sept. 13, 2018).
[4] *In the Matter of PacifiCorp dba Pacific Power, Application for a General Rate Revision*, Docket No. UE 399, Order No. 22-491, Appendix A at 7 (Dec. 16, 2022).

period, which would be December 31, 2025. This treatment is consistent with the Company's 2010,[5] 2012,[6] 2013,[7] 2021[8], and 2023 Rate Cases.[9] However, in accordance with the settlement terms in docket ADV 1529, the Company has excluded all forecast capital projects eligible for recovery under the WMP AAC from the forecasted list of capital additions to electric plant in-service added into Test Period results in this filing.

Q. What components related to wildfire mitigation activities are included in the revenue requirement in this case?

A. Per the agreement reached in docket ADV 1529 (ADV 1529 Agreement) and approved by the Commission on January 9, 2024, all Oregon wildfire mitigation costs recoverable under the WMP AAC, both O&M and capital costs, are being removed from base rates in this filing to be recovered in the WMP AAC.[10] Similarly, pro forma capital projects meeting the eligibility for recovery under the WMP AAC have also not been included in this case.

I will describe the mechanics of this transfer and the method by which these changes are incorporated in this filing in later sections of my testimony. Further details on wildfire mitigation capital costs associated with wildfire mitigation transmission projects outside of Oregon that the Company is seeking to recover in

[5] *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).
[6] *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).
[7] *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).
[8] *See 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).
[9] *See* Order No. 22-491.
[10] *Letter Adopting Staff Report*, Docket No. ADV 1529, Advice No. 23-025, Staff Report, Exhibit 1 (Jan. 9, 2024).

this proceeding can be found in the direct testimony of Company witness Allen Berreth.

Q. Are capital project costs included in rates through this filing inclusive of capital loadings?

A. Yes, in accordance with generally accepted accounting principles and Federal Energy Regulatory Commission (FERC) Electric Plant Instructions, capital project costs included for recovery through rates represent the full cost to build or acquire the project, inclusive of capital loadings, or overheads.

Q. Did Commission Staff raise an issue related to capital loadings in the Company's June 2023 WMP AAC filing?

A. Yes, because PacifiCorp had an update to base rates on January 1, 2023, through the 2023 Rate Case, Commission Staff was concerned about the potential for double recovery of indirect capital loadings based on capitalized labor assumptions in that GRC.

Q. Please describe Commission Staff's concern regarding double recovery of indirect capital loadings in the WMP AAC filing.

A. The Company's WMP AAC filing made in June 2023 reflected incremental capital costs placed in-service from December 17, 2022 through May 31, 2023. WMP capital projects placed in-service prior to December 17, 2022 were included in the Company's compliance filing updating base rates at the conclusion of the Company's 2023 Rate Case, and were approved to be recovered as part of base rates effective January 1, 2023. Because of this, the WMP AAC filing only reflected capital projects placed in-service that were incremental to the amounts that were already being recovered in base rates. As a result, most of the incremental capital costs that the Company sought recovery of in the 2023 WMP AAC filing were placed in-service in calendar year 2023, which was also the forecast test year in the 2023 Rate Case. Accordingly, it was Commission Staff's position that because the 2023 Rate Case would have built into rates an assumed forecast level of capitalized labor costs for the test year 2023, to recover incremental capital placed in-service amounts specific to indirect loadings for that same calendar year through the AAC raised concerns for potential double recovery.

Q. How does the Company's proposed treatment in this proceeding alleviate that concern?

A. As mentioned above, the Company is removing all Oregon WMP capital projects from base rates as part of this GRC filing. This removal includes the indirect capital loadings capitalized as part of the project costs. Also as previously stated, no Oregon forecast capital projects through December 2024 are included in this filing. Therefore, projects placed in-service through December 2024 will be added to the WMP AAC, in the appropriate timed filing, at the fully capitalized cost, including indirect capital loadings, so that the costs are only recovered through the WMP AAC.

Going forward, all WMP capital project costs eligible for recovery through the WMP AAC under the criteria established in the approval of the ADV 1529 filing will be excluded from capital forecasts in GRCs, as long as the WMP AAC mechanism continues to be utilized. Accordingly, WMP capital projects placed in-service as reported in the WMP AAC will always be incremental, as no recovery is reflected in base rates for any of these projects. Only in years where the WMP AAC application seeks to recover costs of capital placed in-service in a year that overlaps with a forecasted test year in an immediately preceding GRC should there be consideration of any indirect capital loading adjustment in the calculation of net WMP capital costs eligible for recovery under the AAC. Otherwise, similar with 2024 assets placed in-service, total WMP project costs should be reflected in WMP AAC filings in its entirety as the total costs are incremental amounts placed in-service and recoverable under the WMP AAC.

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 initially approved by the Commission in docket UM 1050 on January 23, 2020, and further approved for use to jurisdictionally-allocate revenue requirement in Oregon rates through December 2025 on June 27 2023.[11] This is the same allocation methodology used in the Company's 2021 and 2023 Rate Cases.

V. OREGON RESULTS OF OPERATIONS

Q. Please describe Exhibit PAC/1702.

A. Exhibit PAC/1702, 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, 2023, which has been normalized and used to calculate the revenue requirement for the Test Period, the 12 months ending

[11] *See In the Matter of PacifiCorp dba Pacific Power, Petition for Approval of the 2020 Inter-Jurisdictional Allocation Protocol, Docket No. UM 1050*, Order No. 20-024 (Jan. 23, 2020); *See In the Matter of PacifiCorp dba Pacific Power, Petition for Approval of the 2020 Inter-Jurisdictional Allocation Protocol, Docket No. UM 1050*, Order No. 23-229 (Jun. 30, 2023).

December 31, 2025. 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/1702 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 GRC (column 5). Page 1.2 contains a summary of the GRC request.
- 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 2025 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. <u>Tab 3 – Revenue Adjustments</u>

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 forecast loads. Page 3.1.4 shows a breakout of the TAM and GRC revenues.

Confidential Renewable Energy Certificate (REC) Revenues (page 3.2) – This adjustment first removes all REC revenue and REC deferrals booked during the 12 months ended June 2023. 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 No. 10-210 in docket UP 260.[12] REC revenues received through Schedule 272 are then added back into Test Year results on a forecast basis.

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.

Fly Ash Revenue (page 3.4) – Base Period fly ash sales revenues are updated to reflect Test Period levels forecasted for calendar year 2025. Plants with ash sales revenues in the Base Period are Jim Bridger, Naughton, Craig, and Huntington.

[12] *In the matter of PacifiCorp, dba Pacific Power Application Approval of Sale of Renewable Energy Credits*, Docket No. UP 260, Order No. 10-210 at 1 (June 9, 2010).

B. <u>Tab 4 – O&M Adjustments</u>

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.[13] It also reallocates certain gains and losses on property sales and regulatory expenses to reflect the appropriate allocation.

Confidential 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 2023.

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[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).

Collective bargaining agreements are used to escalate union wages where increases are specified,[14] 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.

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 labor costs in the year ended June 2023 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 2025 levels. These expenses have historically been included in the Company's results

[14] 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.

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 were accounted for in its own separate adjustment, starting in the 2023 Rate Case, and this case continues to treat these costs in the same way. All other pension-related service expenses will continue to be included in the WEBA adjustment. This treatment of pension-related non-service expense is consistent with the outcome of the Company's most recently approved GRC. Also consistent with the approved outcome in the same GRC, settlement losses reflected in this case 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 and represents the reversal of an accrual amount that was initially recorded prior to the Base Period. Accordingly, the reversal entry 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.[15] The Commission ordered the accrual to begin on April 1, 2011, as a replacement for the

[15] Order No. 10-473 at 5.

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.

Consistent with the methodology authorized in 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.

In addition to updating the annual property damages reserve accrual amounts, this adjustment continues to include the amortization of the excess Oregon Property Insurance Reserves balance as approved in the Company's last GRC. This amount represented costs that Oregon customers had been underpaying, to the extent that a significant debit balance had accrued in the reserve account. To recover this expense for which Oregon customers had underpaid, the Company proposed in the 2023 Rate Case to amortize the outstanding balance over 10 years, which was approved. Rates approved in docket UE 399 became effective on January 1, 2023. Where the current case starts with base period data from the 12 months ended June 30, 2023, an annualization adjustment is necessary to reflect annual amortization levels in the Test Year.

For self-insured retention third-party liability accrual, the Company continues calculate accrual levels using historical averages, which was the approved treatment in the 2010 Rate Case. Since the Company's 2023 Rate Case, third-party liability accrual in rates is calculated based on a three-year average of historical gross expense net of insurance proceeds using the cash method, using the most recent 3-year time period.

Total-Company Non-T&D property insurance premiums were $5.7 million for the 12 months ended June 2023 and will be reduced slightly to $5.5 million for the Test Period. This reflects the renewal amounts effective August 2023 which is the best known information at this time.

As proposed in the direct testimony of Company witness Joelle R. Steward, the Company is seeking to include the recovery of excess liability insurance premiums in a separate Insurance Cost Adjustment tariff rider supporting the Insurance Mechanism that the Company is intending to file later this year. Accordingly, total-Company excess liability insurance premiums recorded in the Base Period have been removed out of base rates revenue requirement calculations in this case. I discuss in greater detail the Company's proposed recovery of liability insurance expenses in Section VI of my testimony below. For further discussion on the Company's proposed Insurance Cost Adjustment, and excess liability premium projections in this case, please refer to the direct testimonies of Company witnesses Steward and Mariya V. Coleman.

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 2020 to June 2023 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 2021, 2022, and preliminary inputs for 2023. Should actual 2023 inputs, when finalized and available, reflect amounts different than what has been reflected in the Company's direct filing, the Company will update its calculation in its reply testimony to reflect actual, final 2023 inputs in the calculation of revenue-sensitive items in this case. The methodology to calculate Franchise Tax and Resource Supplier Tax using a historical three-year average tax factor was agreed to by the Company in docket UE 374 (2021 Rate Case) and was also approved in customer rates adopted in the 2023 Rate Case. Public Utility Commission Fee continues to be calculated using the approved rate of 0.43 percent, as most recently established by Order No. 23-057 in docket UM 1012.[16]

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.[17] National and regional trade organizations are recognized at 75 percent.

[16] *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. 23-057 (Feb. 23, 2023).
[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).

Meals and Entertainment Adjustment (page 4.9) – This adjustment reflects the disallowance that was ordered by the Commission in Order 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 percent. This adjustment is prepared consistent with the ordered adjustment in Order No. 20-473.

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 these IHS Markit indices for escalation of non-labor O&M expenses is consistent with the Company's past rate cases, including its 2023 Rate Case in which the Commission approved a revenue requirement calculated using these indices. These 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 2023 forecast, released January 22, 2024. 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/1705.

Wildfire and Vegetation Management O&M (page 4.11) – This adjustment removes vegetation management and wildfire mitigation expenses recorded in the Base Period. This adjustment then adds back in the Test Period levels of non-wildfire vegetation management expense into forecasted 2025 results. Test Period vegetation management expenses have been established at $67 million, as explained in the direct testimony of Company witness Berreth. Wildfire mitigation expenses in Oregon[18] that are expected to be recoverable under the WMP AAC, as allowed in the ADV 1529 Agreement, including approximately $19.7 million of Oregon WMP O&M expenses approved in docket UE 399 for recovery in base rates, are not added back into Test Period results. Instead, Oregon WMP O&M expenses will be added into the WMP AAC (Schedule 190) rate true-up calculation, which I discuss in more detail in Section VI below.

Customer Payment Fees (page 4.12) – This adjustment adds into Test Period results the incremental expenses due to the proposed elimination of customer payment fees beginning with the effective date of this GRC. For further details on this proposal, please refer to the direct testimony of Company witness Robert M. Meredith.

Incremental O&M (page 4.13) – This adjustment reflects into Test Period results specific changes to O&M expenses not otherwise accounted for by other adjustments in this case. Jim Bridger Units 1 and 2 are being converted to gas units in 2024. Accordingly, the Company is anticipating that O&M expense levels at Jim Bridger are likely to be lower post-conversion, relative to status quo. The Company has

[18] Oregon WMP O&M costs include only Oregon distribution costs, and Oregon's allocation of transmission costs for WMP activities located inside Oregon, per ADV 1529 Agreement. Transmission O&M for WMP work performed in other states continues to be allocated to Oregon at the system generation (SG) allocation percentage, and is recovered through the GRC.

incorporated this adjustment to reduce O&M expenses by approximately $2.9 million on an Oregon-allocated basis based on consideration of post-conversion avoided costs as discussed in the direct testimony of Company witness Brad D. Richards. This adjustment was calculated by comparing the forecast Jim Bridger Units 1 and 2 O&M expense from the Test Period, against the actual Jim Bridger Units 1 and 2 O&M from the Base Period. The difference is the resulting adjustment. Also reflected through this adjustment is the anticipated change in O&M for the Lower Klamath Fish Hatchery contractual obligation as it relates to the transfer of hydroelectric dam assets to the Klamath River Renewal Corporation (KRRC).

C. <u>Tab 5 – NPC Adjustments</u>

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 GRC. 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 forecast 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 GRC.

WRAP Fees and COSR Materials (page 5.2) – This adjustment updates Western Resource Adequacy Program (WRAP) fees from Base Period levels to amounts estimated for calendar year 2025. This adjustment also adds into Test Period results Committee of State Regulators (COSR) material costs, amounting to approximately $16 thousand on an Oregon-allocated basis.

D. <u>Tab 6 – Depreciation and Amortization Expense Adjustments</u>

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, and incrementally considers the depreciation changes to specific coal-fired generation facilities approved in docket UE 399. 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 2024 pro forma plant balances. Detailed calculation of the depreciation and amortization expense is provided on pages 6.1.4 through 6.1.13.

Depreciation and Amortization Reserve (page 6.2) – This adjustment steps forward the depreciation and amortization reserve from the Base Period to a December 2024 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, 2023, to December 31, 2024. An incremental adjustment has been added to the December 31, 2024 balance to reflect the impact of annualized depreciation expense in adjustment 6.1. The reserve balance calculations are detailed on pages 6.2.4 to 6.2.12.

Repowering Buy-Downs Adjustment (page 6.3) – 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 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.

Confidential Bridger Coal Reclamation Costs (page 6.4) – 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 and in the 2023 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 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/1703.

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.

Power Tax 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, 2024. 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.

TCJA EDIT Adjustment (page 7.7) – This adjustment walks-forward 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, 2024.

Oregon Corporate Activity Tax (OCAT) & Metro Business Income Tax (Metro BIT) Adjustment (page 7.8) – This adjustment adds into base rates the forecasted OCAT and Metro BIT for the Test Period.

Allowance for Funds Used During Construction (AFUDC) Equity (page 7.9) – This adjustment reflects the appropriate level of AFUDC equity into regulated results to align the tax schedule M with regulatory income. Per Commission Order No. 10-022, AFUDC equity in this case is included using flow-through tax treatment.[19]

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 2022 information. An electronic version of the lead lag study is included as part of the Company's workpapers.

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[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).

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 2024. 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, 2024 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]

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[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).

[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).

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, 2024. Capital additions by FERC functional category are listed on pages 8.4.19 to 8.4.28, indicating the in-service date and in-service amounts by project. This adjustment is based on plant balances as of December 31, 2024. 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 8.4.30 through 8.4.36 of the Report.

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 Assets and Liabilities Amortization (page 8.6) – This adjustment normalizes regulatory assets and liabilities to reflect expected changes through the Test Period to balances that are currently amortizing in the Base Period. In addition, the Company is proposing to begin amortization of deferred Oregon Distribution System Plan (DSP) expenses through 2023.[22] The Company is proposing an amortization period of three years, resulting in an annual amortization expense of approximately $856 thousand on an Oregon-allocated basis.

[22] *In the Matter of PacifiCorp, dba Pacific Power, Application for Approval of Deferred Accounting for Operating Costs and Capital Investments Made to Implement PacifiCorp's Distribution System Plan*, Docket No. UM 2220, Application (Jan. 3, 2022), Reauthorization (Jan 3, 2023), Reauthorization (Jan. 3, 2024).

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 No. 01-787.[23]

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 No. 15-226 in docket UM 1633, the net pension and post-retirement prepaid is not to be included in rate base for Oregon.[24]

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 No. 08-548.[25]

Deer Creek Mine Adjustment (page 8.10) – Order No. 15-161 in docket UM 1712 addressed closure of the Deer Creek mine located in Utah and ruled on several issues.[26] Order No. 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

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[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).

[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).

amortized on the basis that amounts were considered preliminary, and the timing of payment was not yet certain. The Company was, however, allowed to continue to defer these costs as approved in docket UM 1712, and the order maintained the Company's ability to seek recovery in a future rate proceeding.[27] At the time this rate case was prepared, discussions have begun in regards to the payment of this royalty obligation. The Company anticipates that payment is likely to occur in 2024. As such, the Company is including the amount of deferred recovery royalties in this proceeding and is proposing to amortize this amount over three years. The Company will continue to assess this amount as discussions continue and update the amounts and payment timing throughout this proceeding as better information becomes available.

This adjustment otherwise removes all Deer Creek regulatory assets and closure costs that have already been previously approved for amortization, from Base Period results, as these amounts are being recovered through a separate tariff rider, with interest at the Modified Blended Treasury Rate (MBTR). 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 historically included in the TAM but was approved to be removed from the TAM to be included in base rates instead in Order No. 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 No. 20-473 in docket UE 374. This adjustment was prepared in the

[27] Order No. 20-473 at 88.

same manner as was included in the Company's compliance filing in the 2021 Rate Case, and also as filed and approved in the 2023 Rate Case.

Transmission Project Adjustment (page 8.12) – This adjustment reflects in results project cost disallowances on specific transmission projects as ordered in Order No. 20-473 in docket UE 374.

Cholla Unit 4 Retirement (page 8.13) – Cholla Unit 4 ceased operations December 31, 2020. As part of 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. More recently, in the Company's 2023 Rate Case, the Company sought recovery of additional closure cost items associated with the Cholla Unit 4 closure for which amounts were not included in the 2021 Rate Case, as the amounts were yet unknown when the 2021 Rate Case was prepared. The recovery request for incremental Cholla Unit 4 closure costs in the 2023 Rate Case included amortization of the deferred safe harbor lease termination payment and non-union severance expenses over three years. Additionally, as authorized in Order No. 20-473, the assessed property tax costs assigned to Cholla Unit 4 through the closure process that had been deferred and were eligible for amortization, with interest to accumulate at the MBTR, was also included in the Company's request in the 2023 Rate Case. In Order No. 22-491, the Company was approved to amortize the deferred property taxes related to Cholla Unit 4 through the closure process in a separate tariff rider, but the amortization of the remaining Cholla Unit 4 closure costs as requested in the 2023 Rate Case remained in base rates.

This adjustment reflects the annual amortization expense associated with the remaining closure costs and a corresponding adjustment to the regulatory asset balance to reflect the 13-month average balance in the Test Period. This adjustment also removes from the Base Period, reserve reversal entries related to Cholla Unit 4 closure costs.

Miscellaneous Rate Base (page 8.14) – 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 has been included in every rate case since.[28]

Carbon Plant Closure (page 8.15) – The Carbon plant was retired in April 2015. 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 reflects in results the amortization and forecast balances for the Test Period.

Removal of Wildfire Mitigation Capital Rate Base (page 8.16) – Consistent with the ADV 1529 Agreement, all Oregon wildfire mitigation costs recoverable under the WMP AAC, both O&M and capital costs, are being removed from base rates in this filing to be recovered in the WMP AAC. This adjustment removes all Oregon WMP

[29] Order No. 13-474 at 3 and App. A at 18.

AAC recovery-eligible wildfire mitigation capital costs in rate base from the Base Period. The removal of depreciation expense for assets removed is reflected in Adjustment 6.1, Depreciation/Amortization Expense Adjustment.

The Schedule 190 rate currently in effect, approved on January 9, 2024, only reflects qualifying Oregon WMP project costs incremental to the pro forma WMP project costs that were included in Oregon base rates which became effective on January 1, 2023. In other words, the recovery for qualifying Oregon WMP project costs placed in-service December 2022 and prior is currently embedded in base rates. With the removal of all WMP AAC recovery-eligible Oregon WMP projects from rate base in this case, a corresponding true-up to the WMP AAC rate will be necessary, to ensure qualifying Oregon WMP project costs that are currently approved and are being recovered in base rates, can continue to be recovered under the WMP AAC, as new base rates becoming effective on January 1, 2025, will no longer reflect those project costs. I discuss this Schedule 190 WMP AAC rate true-up further in Section VI later in my testimony.

Confidential New Wind Generation Capital Additions (page 8.17) – This confidential pro forma adjustment adds into Test Period results the capital addition and depreciation amount for the new wind generation projects expected to be in-service by December 2024. Please refer to the direct testimonies of Company witnesses Jeffrey M. Wagner, Timothy J. Hemstreet, Rick T. Link, and Thomas R. Burns for additional information on these projects.

Wildfire Restoration Costs Deferral Amortization (page 8.18) – This adjustment adds into Test Period results the amortization of deferred revenue requirement associated with the September 2020 wildfire restoration capital projects placed in-service since September 2020, as outlined in docket UM 2116, the Company's application for deferred accounting related to wildfire damage and restoration costs. To calculate the deferred revenue requirement, the Company calculated annual revenue requirement of the assets placed in-service in each deferral year and divided each deferral year's annual revenue requirement by 12 to impute a monthly revenue requirement deferral amount. These monthly amounts are assumed to accrue through December 2024. Upon January 1, 2025, when new rates from the current case becomes effective, deferral of revenue requirement on capital projects placed in-service will no longer be needed, as the full revenue requirement of assets in-service would be in base rates at that time. O&M expenses incurred related to restoration work is also added to the deferral balance each month. The running deferral total then accrues interest at the approved weighted average cost of capital through the deferral period. The interest rate will be reduced to the MBTR upon the time when the balance begins to amortize. For further discussion on the restoration costs deferred, please refer to the direct testimony of Company witness Berreth. Total wildfire restoration costs deferral that the Company is seeking recovery for in this case is approximately $45.2 million, before interest accrual.

This adjustment also adds into Test Period results the amortization of undepreciated investment in plant no longer used and useful due to wildfire damage or destruction—a balance explicitly recommended by Commission Staff and approved by the Commission's order in application docket UM 2116 to be recorded to a regulatory asset separate from the deferred costs associated with damage restoration from the September 2020 wildfires.[29] The Company is seeking approval to amortize deferred costs for wildfire restoration, and the amortization of undepreciated investments no longer used and useful due to wildfire damage over a three-year amortization period.

Aeolus Substation Settlement (page 8.19) – In the settlement stipulation from the Company's 2023 Rate Case, the Company affirmed that none of the plant repairs that resulted from the transformer outage at the Aeolus Substation on September 30, 2021, had been included in the 2023 Rate Case. Stipulating parties agreed, then, that any funds recovered from third parties related to such repairs, not related to the reimbursement of power costs, would be used to credit rate base to offset, in part, or in full, the plant repair costs in the event the Company includes such costs in any future rate filing. A settlement payment for this referenced incident was received September 30, 2023, which is beyond the Company's Base Period data that was used as the starting point to develop the revenue requirement in the current proceeding. This adjustment adds into Test Year results the settlement amount received from a contractor in regards to this repair as a credit to rate base as stipulated in the settlement agreement in docket UE 399.

Klamath Regulatory Asset (page 8.20) – PacifiCorp is a signatory to the Klamath Hydroelectric Settlement Agreement (KHSA), which provides for the transfer of four main-stem Klamath Hydroelectric Project developments, previously licensed to PacifiCorp, to a third-party dam removal entity that will pursue their removal. The Lower Klamath hydroelectric generation assets were transferred to the KRRC for

[29] *In the Matter of PacifiCorp, dba Pacific Power*, *Application for Deferred Accounting Related to Wildfire Damage and Restoration Costs*, Docket No. UM 2116, Order No. 22-154, Appendix A at 6 (May 9, 2022).

final decommissioning in December 2022. At the time of transfer, the remaining net plant balance was initially reclassified from hydro plant to intangible plant as PacifiCorp continued to operate the plants to generate electricity for customers. The Company continued to assume depreciation on the intangible plant assets using a 20 percent rate (i.e. five years depreciable life), consistent with the depreciation rate for Klamath assets approved in docket UE 374. A subsequent determination from FERC denied the Company's inclusion of the balance as intangible plant, and so the balance was then reclassified as a regulatory asset. The Company continues to amortize this balance, now classified as a regulatory asset, assuming the five years' amortization life previously established for Klamath assets.

In this case, the Company is proposing to remove the regulatory asset from rate base with new rates effective in this docket, and to continue this amortization through 2027, which would represent a five-year amortization period from the initial transfer date of these Klamath assets out of electric plant in-service (i.e. December 2022). This mimics the same depreciation period for Klamath assets as established in the 2023 Rate Case for these assets. Interest is proposed to accrue on this balance at the MBTR starting on January 1, 2025, or the rate effective date of this case once base rates no longer reflect this regulatory asset balance for Klamath. This adjustment also removes residual O&M expenses from the Base Period associated with Klamath hydroelectric facilities operations.

G. <u>Tab 9 – 2020 Protocol ECD</u>

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, as approved original in Order No. 20-024 in docket UM 1050, the Fixed ECD, as used in the 2017 Protocol, was to continue for Idaho at $836,000 through the end of 2023. The Dynamic ECD, as used in the 2010 Protocol, was to continue for Oregon through the end of 2023, capped at $11,000,000, per the same order in docket UM 1050. No ECD adjustment exists for Utah or California. In Wyoming, the ECD terminated as of December 31, 2020. On June 30, 2023, Order No. 23-229 was issued under docket UM 1050, extending the use of the 2020 Protocol through 2025.

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. <u>Tab 10 – Allocation Factors</u>

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. <u>Tabs B1 to B20</u>

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. OTHER RATE UPDATES

Q. Is the Company proposing new rate schedules or changes to other existing rate schedules beyond updates described above?

A. Yes. In this proceeding, the Company is proposing new dedicated surcharges to recover excess liability insurance costs (both deferred and on-going), and costs associated with the Catastrophic Fire Fund as described in the direct testimony of Company witness Steward. Also, with the move of all Oregon WMP costs from base rates into the WMP AAC, a true-up to Schedule 190 rates recovering Oregon WMP costs will also need to be made. Finally, the Company is also seeking permission to amortize incremental COVID-19 deferred costs that were not previously in amounts approved for amortization in the Company's 2023 Rate Case.

Q. Please describe the Company's proposal to establish a separate surcharge to recover excess liability insurance costs.

A. As discussed in detail in the direct testimony of Company witness Steward, the Company's proposal is to create a dedicated surcharge, Schedule 80 – Insurance Cost Adjustment, to recover costs related to excess liability insurance. The Insurance Cost Adjustment will be used to support a new Insurance Mechanism that the Company is working with stakeholders to develop. The Company intends to file for approval of the Insurance Mechanism, including liability coverage level, that the Insurance Cost Adjustment will support, subsequent to this GRC filing.

Q. What costs is the Company intending to recover under Schedule 80?

A. The Schedule 80 rate will be established to recover:

- Liability insurance premium amounts deferred under docket UM 2301, PacifiCorp's Application for Authorization of Deferred Accounting Related to Insurance Costs, and
- Projected excess liability insurance premiums for the Test Period.

Q. How much will these costs proposed to be recovered under Schedule 80 amount to?

A. Please refer to Exhibit PAC/1709 for a summary of the total amounts expected to be recovered under Schedule 80. At the time of this filing, the Company anticipates that the total deferred liability insurance premium to be recorded under docket UM 2301 will be approximately $41.3 million, before accrual of interest, on an Oregon-allocated basis. The Company is proposing to amortize the total Oregon-allocated deferred amounts, plus interest accrual, over a three-year amortization period.

Accordingly, the annual amortization amount is estimated to be approximately $15.6 million.

In addition to the amortization amounts outlined in Exhibit PAC/1709, the Company is also proposing to include the projected excess liability insurance premiums for the Test Period for recovery under Schedule 80. As discussed in the direct testimony of Company witnesses Steward and Coleman, total-Company liability insurance premiums are estimated to be approximately $183.9 million, which on an Oregon-allocated basis, translates to an additional $50.4 million to be recovered through Schedule 80 upon its creation. This amount, combined with the anticipated annual amortization of deferred liability insurance premiums, adds up to the total Insurance Cost Adjustment in Schedule 80 of approximately $66.0 million.

Excess liability insurance premiums for the Test Period are currently the Company's best estimate based on available information. As better information becomes available throughout this proceeding, the Company will provide further updates to the amounts that it is seeking to collect through Schedule 80 as necessary.

Q. What about the dedicated surcharge for funding of the Catastrophic Fire Fund?

A. The Company is proposing to create a dedicated surcharge, Schedule 193, to be effective January 1, 2025, to support funding of the Catastrophic Fire Fund. The Company is proposing to collect $77.7 million annually on Schedule 193. For greater discussion on how this amount was derived, please refer to the direct testimony of Company witness Steward.

Q. Please describe the Company's requested update for amounts to be collected for Schedule 190.

A. The currently effective Schedule 190 rate for the WMP AAC is approved to recover 2022 WMP O&M costs incurred that were incremental to amounts reflected in base rates for 2022, projected incremental 2023 WMP O&M above $19.7 million reflected in base rates for 2023, and capital costs for Oregon WMP projects placed in-service between December 17, 2022 through May 31, 2023.[30] With the Company's removal of all Oregon WMP costs, both O&M and capital, from base rates in this filing, a corresponding update to the WMP AAC rate is necessary to ensure amounts previously assumed to be recovered as part of base rates for Oregon WMP activities continues to be recovered from customers, but now through the WMP AAC rate schedule.

Q. What is the anticipated impact to the Schedule 190 rate of transferring the Oregon WMP O&M costs currently approved for recovery in base rates to Schedule 190?

A. The currently approved Oregon WMP O&M in base rates is approximately $19.7 million. Moving this O&M cost into the WMP AAC would result in the Schedule 190 rate going up by approximately $19.7 million.

[30] Oregon WMP capital projects placed in-service through December 16, 2022 were included in the compliance filing for Docket No. UE 399 (2023 Rate Case) and reflected in base rates effective January 1, 2023.

Q. What is the anticipated impact to truing up capital costs recovered under the WMP AAC such that all approved Oregon WMP capital project costs would be recovered under Schedule 190?

A. The impact of truing up capital costs in the WMP AAC to reflect all Oregon WMP capital projects approved for recovery is to be determined. According to established schedules, WMP AAC filings are expected to be made around July 1 each year to incorporate additional incremental costs on an annual basis. Typically, these annual filings would reflect incremental capital placed in-service through May of the filing year, and new rates for the WMP AAC are expected to be effective November of the same year. Based on these assumptions, the true-up to WMP AAC rate that would need to happen on January 1, 2025, will depend on the approved rate for Schedule 190 coming out of the 2024 WMP AAC filing, which should reflect recovery of Oregon WMP capital projects placed in-service through May 2024, that is incremental to Oregon WMP capital projects reflected in the 2023 Rate Case compliance filing.[31]

Q. Can the Company provide an illustrative demonstration of how the January 1, 2025 WMP AAC rate update would be calculated based on the currently approved WMP AAC rate in Schedule 190?

A. Yes. Please refer to Exhibit PAC/1710. Exhibit PAC/1710 is formatted in a way that intentionally mimics the workpaper that was submitted to the Commission in support of the ADV 1529 resolution of the Company's 2023 WMP AAC filing. Tabs that are new or contain information that has changed or been modified from the workpaper

[31] 2023 Rate Case compliance filing reflected Oregon WMP capital projects placed in-service through December 16, 2022.

previously submitted in ADV 1529 have been identified and color-coded in green to facilitate comparison between calculations presented in Exhibit PAC/1710, against those previously presented in the ADV 1529 final workpapers. The true-up of the WMP AAC rate would entail a recalculation of the effective rate under the WMP AAC as of December 31, 2024. Exhibit PAC/1710 assumes no change to the WMP AAC rate between the time of this filing, and the end of December 2024. Based on that, the WMP AAC rate is recalculated to capture an incremental $19.7 million of Oregon WMP O&M costs, and all Oregon WMP capital costs for projects placed in-service through May 2023. Currently approved WMP AAC rates include incremental capital projects through May 2023 only. Updating capital project costs to reflect balances placed in-service only through the May 2023 date ensures that all projects now being recovered through the updated WMP AAC have been audited and reviewed for prudence by the Commission. Oregon WMP capital projects placed in-service December 16, 2022 and prior would have gone through prudence review through the 2023 Rate Case. Oregon WMP capital projects placed in-service form December 17, 2022 through May 31, 2023 would have also gone through prudence review, through the Company's 2023 WMP AAC filing (docket ADV 1529). Based on these assumptions, the WMP AAC rate would go from the currently approved collection of $46.5 million, to a total of $67.7 million, resulting in an approximately $21.2 million increase. This increase in the WMP AAC rate is fully offset by the removal of Oregon WMP AAC O&M and capital costs from base rates.

Q. How would this true-up calculation change if a new WMP AAC rate were approved before December 31, 2024?

A. If a new WMP AAC rate is established before December 31, 2024, then the true-up calculation would need to be calculated relative to the approved 2024 WMP AAC rate. Specifically, the 2024 WMP AAC rate would reflect Oregon WMP capital projects placed in-service through May 2024. Accordingly, the Oregon WMP capital projects to be included in the true-up calculation would have to be updated to reflect actual total project costs placed in-service through May 2024, rather than May 2023 as presented in the illustrative calculation in Exhibit PAC/1710.

Q. Is there another rate schedule the Company is proposing to modify as part of this rate case?

A. Yes, in this GRC, the Company is also seeking to recover incremental COVID-19 deferred costs not previously included in the approved recovery in the 2023 Rate Case. In that docket, Staff recommended for inclusion into rates for recovery of COVID-19 deferred costs from 2020 and 2021 over three years. In its reply filing, the Company found it reasonable to accept Staff's proposal to begin amortization of those costs, but because of the magnitude of the deferred balance, the Company recommended a four-year amortization period instead. Ultimately, a four-year amortization period was adopted through approval of the settlement agreement in that docket. As currently approved, COVID-19 deferred costs through December 2021 are currently amortizing through Schedule 192 over four years, with an annual amortization estimate of approximately $5.0 million.

Since the end of 2021, further costs have been deferred under the COVID-19 deferral. These costs are as outlined in the quarterly reports the Company files under docket UE 185. In this docket, the Company is seeking approval to add an additional $8.5 million of deferred COVID-19 costs recorded in 2022 through September 2023 to be amortized through Schedule 192. These costs represent incremental amounts for which the Company had not previously received recovery of, representing additional COVID-19 related costs including:

- Higher bad debt expenses,
- Costs to fund bill payment assistance program,
- Waived late fees,
- Increased labor and additional facilities to enable social distancing,
- Personal protective equipment, cleaning supplies and contract tracing,
- Technology costs to allow employees to work remotely,
- Cost reduction from lower employee expenses such as travel and training, and
- CARES Act savings.

Q. Is the Company proposing to recover these incremental costs by revising the currently approved Schedule 192 rate?

A. No. The Company's proposal is to allow the Schedule 192 rate to remain as approved but allow the currently approved rate to run beyond the previously approved four-year amortization period until the incremental $8.5 million, plus interest accrual, is recuperated. Based on estimated annual collection amount of approximately $5.0 million for COVID-19 deferred costs currently approved, the additional $8.5 million is expected to extend the collection timeline of this amount through June

2029. Please refer to Exhibit PAC/1711 for details of the updated COVID-19 deferred amounts that will be collected, and an illustration of the updated amortization schedule.

VII. CONCLUSION

Q. Please summarize your testimony.

A. I recommend that the Commission approve the requested $157.7 million increase and non-NPC revenue requirement of $1,234.2 million. I further recommend the Commission approve the addition of Schedules 80, and 193 for recovery of excess liability insurance costs, and funding of the Catastrophic Fire Find, as well as modifications to Schedules 190, and 192 as described in my testimony above.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 433
Exhibit PAC/1701
Witness: Sherona L. Cheung

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Sherona L. Cheung

Revenue Requirement Summary

February 2024

PacifiCorp
OREGON
Normalized Results of Operations - 2020 PROTOCOL
Twelve Months Ending December 31, 2025

		(1)	(2)	(3)	(4)	(5)	(6)
			(3) - (1)	Ref. Page 1.2			(3) + (4) + (5)
					TAM	**GRC**	
		NPC-Related Results	Non-NPC Related Results	Total Adjusted Results	NPC-Related Under Recovery	Requested Non-NPC Related Price Change	Total Normalized Results with Price Change
1	Operating Revenues:						
2	General Business Revenues	604,412,863	1,076,524,475	1,680,937,338	(18,264,624)	157,663,819	1,820,336,533
3	Interdepartmental		-	-			-
4	Special Sales	92,078,056	-	92,078,056			92,078,056
5	Other Operating Revenues		71,932,639	71,932,639			71,932,639
6	Total Operating Revenues	696,490,919	1,148,457,114	1,844,948,033	(18,264,624)	157,663,819	1,984,347,228
7							
8	Operating Expenses:						
9	Steam Production	147,610,878	88,739,462	236,350,339			236,350,339
10	Nuclear Production		-	-			-
11	Hydro Production		13,610,836	13,610,836			13,610,836
12	Other Power Supply	571,959,299	30,332,071	602,291,370			602,291,370
13	Transmission	45,115,602	19,633,397	64,748,998			64,748,998
14	Distribution		114,708,178	114,708,178			114,708,178
15	Customer Accounting		31,422,542	31,422,542		872,291	32,294,833
16	Customer Service & Info		5,308,096	5,308,096			5,308,096
17	Sales		-	-			-
18	Administrative & General		61,612,724	61,612,724			61,612,724
19							
20	Total O&M Expenses	764,685,778	365,367,305	1,130,053,083	-	872,291	1,130,925,374
21							
22	Depreciation		317,077,683	317,077,683			317,077,683
23	Amortization		30,904,843	30,904,843			30,904,843
24	Taxes Other Than Income		100,572,803	100,572,803		3,932,410	104,505,214
25	Income Taxes - Federal	(78,872,787)	36,078,107	(42,794,680)	(3,661,436)	30,643,056	(15,813,060)
26	Income Taxes - State	(3,096,047)	8,403,176	5,307,130	(829,214)	6,939,804	11,417,720
27	Income Taxes - Def Net		(4,937,211)	(4,937,211)			(4,937,211)
28	Investment Tax Credit Adj.		-	-			-
29	Misc Revenue & Expense		(30,006)	(30,006)			(30,006)
30							
31	Total Operating Expenses:	682,716,945	853,436,699	1,536,153,644	(4,490,650)	42,387,561	1,574,050,555
32							
33	Operating Rev For Return:	13,773,974	295,020,414	308,794,389	(13,773,974)	115,276,258	410,296,672
34							
35	Rate Base:						
36	Electric Plant In Service		10,425,808,241	10,425,808,241			10,425,808,241
37	Plant Held for Future Use		-	-			-
38	Misc Deferred Debits		101,941,905	101,941,905			101,941,905
39	Elec Plant Acq Adj		703,248	703,248			703,248
40	Pension		-	-			-
41	Prepayments		16,838,184	16,838,184			16,838,184
42	Fuel Stock		37,268,548	37,268,548			37,268,548
43	Material & Supplies		129,822,071	129,822,071			129,822,071
44	Working Capital		47,868,648	47,868,648			47,868,648
45	Weatherization Loans		-	-			-
46	Misc Rate Base		-	-			-
47							
48	Total Electric Plant:	-	10,760,250,845	10,760,250,845			10,760,250,845
49							
50	Rate Base Deductions:						
51	Accum Prov For Deprec		(4,043,129,802)	(4,043,129,802)			(4,043,129,802)
52	Accum Prov For Amort		(232,858,605)	(232,858,605)			(232,858,605)
53	Accum Def Income Tax		(703,568,427)	(703,568,427)			(703,568,427)
54	Unamortized ITC		(40,918)	(40,918)			(40,918)
55	Customer Adv For Const		(46,658,522)	(46,658,522)			(46,658,522)
56	Customer Service Deposits		-	-			-
57	Misc Rate Base Deductions		(433,111,498)	(433,111,498)			(433,111,498)
58							
59	Total Rate Base Deductions	-	(5,459,367,773)	(5,459,367,773)			(5,459,367,773)
60							
61	Total Rate Base:	-	5,300,883,073	5,300,883,073			5,300,883,073
62							
63	Return on Rate Base			5.825%			7.740%
64							
65	Return on Equity			6.470%			10.300%

PacifiCorp
OREGON
Normalized Results of Operations - 2020 PROTOCOL
Twelve Months Ending December 31, 2025

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	1,076,524,475	157,663,819	1,234,188,294
3	Interdepartmental	-		-
4	Special Sales	-		-
5	Other Operating Revenues	71,932,639		71,932,639
6	Total Operating Revenues	1,148,457,114	157,663,819	1,306,120,933
7				
8	Operating Expenses:			
9	Steam Production	88,739,462		88,739,462
10	Nuclear Production	-		-
11	Hydro Production	13,610,836		13,610,836
12	Other Power Supply	30,332,071		30,332,071
13	Transmission	19,633,397		19,633,397
14	Distribution	114,708,178		114,708,178
15	Customer Accounting	31,422,542	872,291	32,294,833
16	Customer Service & Info	5,308,096		5,308,096
17	Sales	-		-
18	Administrative & General	61,612,724		61,612,724
19				
20	Total O&M Expenses	365,367,305	872,291	366,239,596
21				
22	Depreciation	317,077,683		317,077,683
23	Amortization	30,904,843		30,904,843
24	Taxes Other Than Income	100,572,803	3,932,410	104,505,214
25	Income Taxes - Federal	36,078,107	30,643,056	66,721,163
26	Income Taxes - State	8,403,176	6,939,804	15,342,980
27	Income Taxes - Def Net	(4,937,211)		(4,937,211)
28	Investment Tax Credit Adj.	-		-
29	Misc Revenue & Expense	(30,006)		(30,006)
30				
31	Total Operating Expenses:	853,436,699	42,387,561	895,824,260
32				
33	Operating Rev For Return:	295,020,414	115,276,258	410,296,672
34				
35	Rate Base:			
36	Electric Plant In Service	10,425,808,241		10,425,808,241
37	Plant Held for Future Use	-		-
38	Misc Deferred Debits	101,941,905		101,941,905
39	Elec Plant Acq Adj	703,248		703,248
40	Pension	-		-
41	Prepayments	16,838,184		16,838,184
42	Fuel Stock	37,268,548		37,268,548
43	Material & Supplies	129,822,071		129,822,071
44	Working Capital	47,868,648		47,868,648
45	Weatherization Loans	-		-
46	Misc Rate Base	-		-
47				
48	Total Electric Plant:	10,760,250,845		10,760,250,845
49				
50	Rate Base Deductions:			
51	Accum Prov For Deprec	(4,043,129,802)		(4,043,129,802)
52	Accum Prov For Amort	(232,858,605)		(232,858,605)
53	Accum Def Income Tax	(703,568,427)		(703,568,427)
54	Unamortized ITC	(40,918)		(40,918)
55	Customer Adv For Const	(46,658,522)		(46,658,522)
56	Customer Service Deposits	-		-
57	Misc Rate Base Deductions	(433,111,498)		(433,111,498)
58				
59	Total Rate Base Deductions	(5,459,367,773)		(5,459,367,773)
60				
61	Total Rate Base:	5,300,883,073		5,300,883,073
62				
63	Return on Rate Base	5.565%		7.740%
64				
65	Return on Equity	5.951%		10.300%
66				
67	TAX CALCULATION:			
68	Operating Revenue	334,564,486	152,859,118	487,423,604
69	Other Deductions			
70	Interest (AFUDC)	(65,590,851)	-	(65,590,851)
71	Interest	137,265,413	-	137,265,413
72	Schedule "M" Additions	434,539,308	-	434,539,308
73	Schedule "M" Deductions	517,163,102	-	517,163,102
74	Income Before Tax	180,266,131	152,859,118	333,125,249
75				
76	State Income Taxes	8,403,176	6,939,804	15,342,980
77	Taxable Income	171,862,955	145,919,314	317,782,268
78				
79	Federal Income Taxes + Other	36,078,107	30,643,056	66,721,163

PacifiCorp
OREGON
Normalized Results of Operations - 2020 PROTOCOL
Twelve Months Ending December 31, 2025

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	604,412,863	(18,264,624)	586,148,239
3	Interdepartmental	-		-
4	Special Sales	92,078,056		92,078,056
5	Other Operating Revenues	-		-
6	Total Operating Revenues	696,490,919	(18,264,624)	678,226,295
7				
8	Operating Expenses:			
9	Steam Production	147,610,878		147,610,878
10	Nuclear Production	-		-
11	Hydro Production	-		-
12	Other Power Supply	571,959,299		571,959,299
13	Transmission	45,115,602		45,115,602
14	Distribution	-		-
15	Customer Accounting	-	-	-
16	Customer Service & Info	-		-
17	Sales	-		-
18	Administrative & General	-		-
19				
20	Total O&M Expenses	764,685,778	-	764,685,778
21				
22	Depreciation	-		-
23	Amortization	-		-
24	Taxes Other Than Income	-	-	-
25	Income Taxes - Federal	(78,872,787)	(3,661,436)	(82,534,223)
26	Income Taxes - State	(3,096,047)	(829,214)	(3,925,261)
27	Income Taxes - Def Net	-		-
28	Investment Tax Credit Adj.	-		-
29	Misc Revenue & Expense	-		-
30				
31	Total Operating Expenses:	682,716,945	(4,490,650)	678,226,295
32				
33	Operating Rev For Return:	13,773,974	(13,773,974)	-
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	(68,194,859)	(18,264,624)	(86,459,483)
69	Other Deductions			
70	Interest (AFUDC)	-	-	-
71	Interest	-	-	-
72	Schedule "M" Additions	-	-	-
73	Schedule "M" Deductions	-	-	-
74	Income Before Tax	(68,194,859)	(18,264,624)	(86,459,483)
75				
76	State Income Taxes	(3,096,047)	(829,214)	(3,925,261)
77	Taxable Income	(65,098,813)	(17,435,410)	(82,534,223)
78				
79	Federal Income Taxes + Other	(78,872,787)	(3,661,436)	(82,534,223)

PacifiCorp
OREGON
Normalized Results of Operations - 2020 PROTOCOL
Twelve Months Ending December 31, 2025

		(1) Total Adjusted Results	(2) Price Change	(3) Results with Price Change
1	Operating Revenues:			
2	General Business Revenues	1,680,937,338	139,399,195	1,820,336,533
3	Interdepartmental	-		
4	Special Sales	92,078,056		
5	Other Operating Revenues	71,932,639		
6	Total Operating Revenues	1,844,948,033		
7				
8	Operating Expenses:			
9	Steam Production	236,350,339		
10	Nuclear Production	-		
11	Hydro Production	13,610,836		
12	Other Power Supply	602,291,370		
13	Transmission	64,748,998		
14	Distribution	114,708,178		
15	Customer Accounting	31,422,542	872,291	32,294,833
16	Customer Service & Info	5,308,096		
17	Sales	-		
18	Administrative & General	61,612,724		
19				
20	Total O&M Expenses	1,130,053,083		
21				
22	Depreciation	317,077,683		
23	Amortization	30,904,843		
24	Taxes Other Than Income	100,572,803	3,932,410	104,505,214
25	Income Taxes - Federal	(42,794,680)	26,981,620	(15,813,060)
26	Income Taxes - State	5,307,130	6,110,590	11,417,720
27	Income Taxes - Def Net	(4,937,211)		
28	Investment Tax Credit Adj.	-		
29	Misc Revenue & Expense	(30,006)		
30				
31	Total Operating Expenses:	1,536,153,644	37,896,911	1,574,050,555
32				
33	Operating Rev For Return:	308,794,389	101,502,284	410,296,672
34				
35	Rate Base:			
36	Electric Plant In Service	10,425,808,241		
37	Plant Held for Future Use	-		
38	Misc Deferred Debits	101,941,905		
39	Elec Plant Acq Adj	703,248		
40	Pensions	-		
41	Prepayments	16,838,184		
42	Fuel Stock	37,268,548		
43	Material & Supplies	129,822,071		
44	Working Capital	47,868,648		
45	Weatherization Loans	-		
46	Misc Rate Base	-		
47				
48	Total Electric Plant:	10,760,250,845	-	10,760,250,845
49				
50	Rate Base Deductions:			
51	Accum Prov For Deprec	(4,043,129,802)		
52	Accum Prov For Amort	(232,858,605)		
53	Accum Def Income Tax	(703,568,427)		
54	Unamortized ITC	(40,918)		
55	Customer Adv For Const	(46,658,522)		
56	Customer Service Deposits	-		
57	Misc Rate Base Deductions	(433,111,498)		
58				
59	Total Rate Base Deductions	(5,459,367,773)	-	(5,459,367,773)
60				
61	Total Rate Base:	5,300,883,073	-	5,300,883,073
62				
63	Return on Rate Base	5.825%		7.740%
64				
65	Return on Equity	6.470%		10.300%
66				
67	TAX CALCULATION:			
68	Operating Revenue	266,369,627	134,594,493	400,964,120
69	Other Deductions			
70	Interest (AFUDC)	(65,590,851)	-	(65,590,851)
71	Interest	137,265,413	-	137,265,413
72	Schedule "M" Additions	434,539,308	-	434,539,308
73	Schedule "M" Deductions	517,163,102	-	517,163,102
74	Income Before Tax	112,071,272	134,594,493	246,665,765
75				
76	State Income Taxes	5,307,130	6,110,590	11,417,720
77	Taxable Income	106,764,142	128,483,903	235,248,045
78				
79	Federal Income Taxes + Other	(42,794,680)	26,981,620	(15,813,060)

PacifiCorp
Oregon General Rate Case
Adjustment Summary
Twelve Months Ending December 31, 2025

		Exhibit PAC/1702		Exhibit PAC/1702			
				Tab 3	Tab 4	Tab 5	Tab 6
		TOTAL COMPANY UNADJUSTED RESULTS JUNE 2023	OREGON ALLOCATED UNADJUSTED RESULTS JUNE 2023	Revenue Adjustments	O&M Adjustments	Net Power Cost Adjustments	Depreciation & Amortization Adjustments
1	Operating Revenues:						
2	General Business Revenues	5,314,367,832	1,399,023,529	280,144,493	1,769,316	-	-
3	Interdepartmental	-	-	-	-	-	-
4	Special Sales	276,874,873	70,586,388	-	-	21,491,668	-
5	Other Operating Revenues	272,845,382	74,297,451	1,710,577	-	-	-
6	Total Operating Revenues	5,864,088,087	1,543,907,367	281,855,070	1,769,316	21,491,668	-
7							
8	Operating Expenses:						
9	Steam Production	929,501,268	246,336,079	-	354,350	(13,786,753)	3,818,882
10	Nuclear Production	-	-	-	-	-	-
11	Hydro Production	42,657,730	11,468,171	-	2,706,114	-	-
12	Other Power Supply	1,454,847,175	520,565,938	-	2,671,783	78,154,638	-
13	Transmission	247,176,958	66,310,208	-	(1,931,955)	370,746	-
14	Distribution	282,601,391	104,588,448	-	9,263,977	-	-
15	Customer Accounting	80,792,201	23,991,155	-	7,431,387	-	-
16	Customer Service & Info	158,979,871	4,916,333	-	391,763	-	-
17	Sales	-	-	-	-	-	-
18	Administrative & General	630,431,721	172,101,036	-	(110,837,989)	-	-
19							
20	Total O&M Expenses	3,826,988,315	1,150,277,368	-	(89,950,571)	64,738,631	3,818,882
21							
22	Depreciation	993,452,379	271,108,388	-	-	-	40,255,866
23	Amortization	76,333,322	15,984,719	-	-	-	(2,716,107)
24	Taxes Other Than Income	188,692,373	74,630,102	-	6,690,549	-	-
25	Income Taxes - Federal	(251,536,478)	(73,225,613)	56,491,598	17,957,678	(8,677,947)	(3,114,987)
26	Income Taxes - State	(2,433,217)	(1,498,603)	12,793,783	4,066,917	(1,965,315)	(705,458)
27	Income Taxes - Def Net	55,172,095	(9,956,034)	-	(1,865,118)	-	(938,932)
28	Investment Tax Credit Adj.	(910,300)	-	-	-	-	-
29	Misc Revenue & Expense	(396,311)	(50,000)	-	19,995	-	-
30							
31	Total Operating Expenses:	4,885,362,180	1,427,270,327	69,285,381	(63,080,549)	54,095,369	36,599,264
32							
33	Operating Rev For Return:	978,725,907	116,637,039	212,569,689	64,849,865	(32,603,701)	(36,599,264)
34							
35	Rate Base:						
36	Electric Plant In Service	32,886,279,146	9,145,444,083	-	-	-	-
37	Plant Held for Future Use	14,174,575	7,461,409	-	-	-	-
38	Misc Deferred Debits	1,636,633,742	182,518,703	-	-	-	-
39	Elec Plant Acq Adj	11,954,169	723,506	-	-	-	-
40	Pensions	104,951,393	28,783,408	-	-	-	-
41	Prepayments	96,171,480	16,838,184	-	-	-	-
42	Fuel Stock	137,605,040	36,243,955	-	-	-	-
43	Material & Supplies	407,130,439	129,822,071	-	-	-	-
44	Working Capital	126,195,894	46,667,656	2,072,867	(1,832,030)	1,618,415	(47)
45	Weatherization Loans	224,530,257	-	-	-	-	-
46	Misc Rate Base	-	-	-	-	-	-
47							
48	Total Electric Plant:	35,645,626,136	9,594,502,976	2,072,867	(1,832,030)	1,618,415	(47)
49							
50	Rate Base Deductions:						
51	Accum Prov For Deprec	(11,020,394,328)	(3,223,614,207)	-	-	-	(817,609,078)
52	Accum Prov For Amort	(731,617,791)	(207,213,607)	-	-	-	(25,921,413)
53	Accum Def Income Tax	(2,927,745,908)	(674,015,477)	-	(38,564,469)	-	1,988,755
54	Unamortized ITC	(2,260,839)	(45,635)	-	-	-	-
55	Customer Adv For Const	(193,419,991)	(73,982,464)	-	-	-	-
56	Customer Service Deposits	-	-	-	-	-	-
57	Misc Rate Base Deductions	(2,624,994,265)	(610,776,749)	-	156,851,573	-	(8,088,788)
58							
59	Total Rate Base Deductions	(17,500,433,122)	(4,789,648,140)	-	118,287,105	-	(849,630,523)
60							
61	Total Rate Base:	18,145,193,015	4,804,854,836	2,072,867	116,455,075	1,618,415	(849,630,570)
62							
63	Return on Rate Base		2.427%	4.421%	1.155%	-0.665%	0.632%
64							
65	Return on Equity		-0.325%	8.842%	2.310%	-1.329%	1.264%
66							
67	TAX CALCULATION:						
68	Operating Revenue		31,956,790	281,855,070	85,009,343	(43,246,962)	(41,358,641)
69	Other Deductions						
70	Interest (AFUDC)		(27,057,087)	-	-	-	-
71	Interest		124,420,851	53,677	3,015,583	41,909	(22,001,031)
72	Schedule "M" Additions		349,040,084	-	7,585,912	-	3,818,882
73	Schedule "M" Deductions		382,368,862	-	-	-	-
74	Income Before Tax		(98,735,753)	281,801,394	89,579,671	(43,288,871)	(15,538,728)
75							
76	State Income Taxes		(1,498,603)	12,793,783	4,066,917	(1,965,315)	(705,458)
77	Taxable Income		(97,237,150)	269,007,610	85,512,754	(41,323,556)	(14,833,270)
78							
79	Federal Income Taxes + Other		(73,225,613)	56,491,598	17,957,678	(8,677,947)	(3,114,987)
	APPROXIMATE PRICE CHANGE		350,528,448	(291,740,043)	(76,613,297)	44,948,662	(40,051,957)

PacifiCorp
Oregon General Rate Case
Adjustment Summary
Twelve Months Ending December 31, 2025

	Exhibit PAC/1702		
	Tab 7	Tab 8	OR Allocated
	Tax Adjustments	Rate Base Adjustments	Results of Operations December 2025
1 Operating Revenues:			
2 General Business Revenues	-	-	1,680,937,338
3 Interdepartmental	-	-	-
4 Special Sales	-	-	92,078,056
5 Other Operating Revenues	-	(4,075,388)	71,932,639
6 Total Operating Revenues	-	(4,075,388)	1,844,948,033
7			
8 Operating Expenses:			
9 Steam Production	-	(372,219)	236,350,339
10 Nuclear Production	-	-	-
11 Hydro Production	-	(563,449)	13,610,836
12 Other Power Supply	-	899,010	602,291,370
13 Transmission	-	-	64,748,998
14 Distribution	-	855,753	114,708,178
15 Customer Accounting	-	-	31,422,542
16 Customer Service & Info	-	-	5,308,096
17 Sales	-	-	-
18 Administrative & General	-	349,677	61,612,724
19			
20 Total O&M Expenses	-	1,168,773	1,130,053,083
21			
22 Depreciation	-	5,713,429	317,077,683
23 Amortization	-	17,636,230	30,904,843
24 Taxes Other Than Income	19,252,152	-	100,572,803
25 Income Taxes - Federal	(28,534,545)	(3,690,866)	(42,794,680)
26 Income Taxes - State	(6,548,315)	(835,879)	5,307,130
27 Income Taxes - Def Net	18,161,605	(10,338,733)	(4,937,211)
28 Investment Tax Credit Adj.	-	-	-
29 Misc Revenue & Expense	-	-	(30,006)
30			
31 Total Operating Expenses:	2,330,897	9,652,955	1,536,153,644
32			
33 Operating Rev For Return:	(2,330,897)	(13,728,343)	308,794,389
34			
35 Rate Base:			
36 Electric Plant In Service	-	1,280,364,158	10,425,808,241
37 Plant Held for Future Use	-	(7,461,409)	-
38 Misc Deferred Debits	-	(80,576,798)	101,941,905
39 Elec Plant Acq Adj	-	(20,258)	703,248
40 Pensions	-	(28,783,408)	-
41 Prepayments	-	-	16,838,184
42 Fuel Stock	-	1,024,593	37,268,548
43 Material & Supplies	-	-	129,822,071
44 Working Capital	(473,620)	(184,593)	47,868,648
45 Weatherization Loans	-	-	-
46 Misc Rate Base	-	-	-
47			
48 Total Electric Plant:	(473,620)	1,164,362,284	10,760,250,845
49			
50 Rate Base Deductions:			
51 Accum Prov For Deprec	-	(1,906,517)	(4,043,129,802)
52 Accum Prov For Amort	-	276,415	(232,858,605)
53 Accum Def Income Tax	(34,395,710)	41,418,474	(703,568,427)
54 Unamortized ITC	4,716	-	(40,918)
55 Customer Adv For Const	-	27,323,942	(46,658,522)
56 Customer Service Deposits	-	-	-
57 Misc Rate Base Deductions	29,710,341	(807,875)	(433,111,498)
58			
59 Total Rate Base Deductions	(4,680,653)	66,304,439	(5,459,367,773)
60			
61 Total Rate Base:	(5,154,273)	1,230,666,723	5,300,883,073
62			
63 Return on Rate Base	-0.047%	-2.099%	5.825%
64			
65 Return on Equity	-0.094%	-4.197%	6.470%
66			
67 TAX CALCULATION:			
68 Operating Revenue	(19,252,152)	(28,593,820)	266,369,627
69 Other Deductions			
70 Interest (AFUDC)	(38,533,764)	-	(65,590,851)
71 Interest	(133,469)	31,867,893	137,265,413
72 Schedule "M" Additions	40,628,028	33,466,404	434,539,308
73 Schedule "M" Deductions	143,378,120	(8,583,880)	517,163,102
74 Income Before Tax	(83,335,010)	(18,411,430)	112,071,272
75			
76 State Income Taxes	(6,548,315)	(835,879)	5,307,130
77 Taxable Income	(76,786,695)	(17,575,551)	106,764,142
78			
79 Federal Income Taxes + Other	(28,534,545)	(3,690,866)	(42,794,680)
APPROXIMATE PRICE CHANGE	2,653,261	149,674,120	139,399,195

Docket No. UE 433
Exhibit PAC/1702
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 2025

February 2024

Tab 1 - Summary

PacifiCorp
OREGON
Normalized Results of Operations - 2020 PROTOCOL
Twelve Months Ending December 31, 2025

(1)	Test Period 2020 Protocol Revenue Requirement	1,820,336,533	Page 1.1
(2)	Normalized General Business Revenues	1,680,937,338	Page 1.1
(3)	2020 Protocol Price Change	**139,399,195**	Page 1.4

PacifiCorp
OREGON
Normalized Results of Operations - 2020 PROTOCOL
Twelve Months Ending December 31, 2025

		(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	604,412,863	1,076,524,475	1,680,937,338	(18,264,624)	157,663,819	1,820,336,533
3	Interdepartmental		-	-			-
4	Special Sales	92,078,056	-	92,078,056			92,078,056
5	Other Operating Revenues		71,932,639	71,932,639			71,932,639
6	Total Operating Revenues	696,490,919	1,148,457,114	1,844,948,033	(18,264,624)	157,663,819	1,984,347,228
7							
8	Operating Expenses:						
9	Steam Production	147,610,878	88,739,462	236,350,339			236,350,339
10	Nuclear Production		-	-			-
11	Hydro Production		13,610,836	13,610,836			13,610,836
12	Other Power Supply	571,959,299	30,332,071	602,291,370			602,291,370
13	Transmission	45,115,602	19,633,397	64,748,998			64,748,998
14	Distribution		114,708,178	114,708,178			114,708,178
15	Customer Accounting		31,422,542	31,422,542		872,291	32,294,833
16	Customer Service & Info		5,308,096	5,308,096			5,308,096
17	Sales		-	-			-
18	Administrative & General		61,612,724	61,612,724			61,612,724
19							
20	Total O&M Expenses	764,685,778	365,367,305	1,130,053,083	-	872,291	1,130,925,374
21							
22	Depreciation		317,077,683	317,077,683			317,077,683
23	Amortization		30,904,843	30,904,843			30,904,843
24	Taxes Other Than Income		100,572,803	100,572,803		3,932,410	104,505,214
25	Income Taxes - Federal	(78,872,787)	36,078,107	(42,794,680)	(3,661,436)	30,643,056	(15,813,060)
26	Income Taxes - State	(3,096,047)	8,403,176	5,307,130	(829,214)	6,939,804	11,417,720
27	Income Taxes - Def Net		(4,937,211)	(4,937,211)			(4,937,211)
28	Investment Tax Credit Adj.		-	-			-
29	Misc Revenue & Expense		(30,006)	(30,006)			(30,006)
30							
31	Total Operating Expenses:	682,716,945	853,436,699	1,536,153,644	(4,490,650)	42,387,561	1,574,050,555
32							
33	Operating Rev For Return:	13,773,974	295,020,414	308,794,389	(13,773,974)	115,276,258	410,296,672
34							
35	Rate Base:						
36	Electric Plant In Service		10,425,808,241	10,425,808,241			10,425,808,241
37	Plant Held for Future Use		-	-			-
38	Misc Deferred Debits		101,941,905	101,941,905			101,941,905
39	Elec Plant Acq Adj		703,248	703,248			703,248
40	Pension		-	-			-
41	Prepayments		16,838,184	16,838,184			16,838,184
42	Fuel Stock		37,268,548	37,268,548			37,268,548
43	Material & Supplies		129,822,071	129,822,071			129,822,071
44	Working Capital		47,868,648	47,868,648			47,868,648
45	Weatherization Loans		-	-			-
46	Misc Rate Base		-	-			-
47							
48	Total Electric Plant:	-	10,760,250,845	10,760,250,845			10,760,250,845
49							
50	Rate Base Deductions:						
51	Accum Prov For Deprec		(4,043,129,802)	(4,043,129,802)			(4,043,129,802)
52	Accum Prov For Amort		(232,858,605)	(232,858,605)			(232,858,605)
53	Accum Def Income Tax		(703,568,427)	(703,568,427)			(703,568,427)
54	Unamortized ITC		(40,918)	(40,918)			(40,918)
55	Customer Adv For Const		(46,658,522)	(46,658,522)			(46,658,522)
56	Customer Service Deposits		-	-			-
57	Misc Rate Base Deductions		(433,111,498)	(433,111,498)			(433,111,498)
58							
59	Total Rate Base Deductions	-	(5,459,367,773)	(5,459,367,773)			(5,459,367,773)
60							
61	Total Rate Base:	-	5,300,883,073	5,300,883,073			5,300,883,073
62							
63	Return on Rate Base			5.825%			7.740%
64							
65	Return on Equity			6.470%			10.300%

Ref. Page 1.4

PacifiCorp
OREGON
Normalized Results of Operations - 2020 PROTOCOL
Twelve Months Ending December 31, 2025

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	1,076,524,475	157,663,819	1,234,188,294
3	Interdepartmental	-		-
4	Special Sales	-		-
5	Other Operating Revenues	71,932,639		71,932,639
6	Total Operating Revenues	1,148,457,114	157,663,819	1,306,120,933
7				
8	Operating Expenses:			
9	Steam Production	88,739,462		88,739,462
10	Nuclear Production	-		-
11	Hydro Production	13,610,836		13,610,836
12	Other Power Supply	30,332,071		30,332,071
13	Transmission	19,633,397		19,633,397
14	Distribution	114,708,178		114,708,178
15	Customer Accounting	31,422,542	872,291	32,294,833
16	Customer Service & Info	5,308,096		5,308,096
17	Sales	-		-
18	Administrative & General	61,612,724		61,612,724
19				
20	Total O&M Expenses	365,367,305	872,291	366,239,596
21				
22	Depreciation	317,077,683		317,077,683
23	Amortization	30,904,843		30,904,843
24	Taxes Other Than Income	100,572,803	3,932,410	104,505,214
25	Income Taxes - Federal	36,078,107	30,643,056	66,721,163
26	Income Taxes - State	8,403,176	6,939,804	15,342,980
27	Income Taxes - Def Net	(4,937,211)		(4,937,211)
28	Investment Tax Credit Adj.	-		-
29	Misc Revenue & Expense	(30,006)		(30,006)
30				
31	Total Operating Expenses:	853,436,699	42,387,561	895,824,260
32				
33	Operating Rev For Return:	295,020,414	115,276,258	410,296,672
34				
35	Rate Base:			
36	Electric Plant In Service	10,425,808,241		10,425,808,241
37	Plant Held for Future Use	-		-
38	Misc Deferred Debits	101,941,905		101,941,905
39	Elec Plant Acq Adj	703,248		703,248
40	Pension	-		-
41	Prepayments	16,838,184		16,838,184
42	Fuel Stock	37,268,548		37,268,548
43	Material & Supplies	129,822,071		129,822,071
44	Working Capital	47,868,648		47,868,648
45	Weatherization Loans	-		-
46	Misc Rate Base	-		-
47				
48	Total Electric Plant:	10,760,250,845		10,760,250,845
49				
50	Rate Base Deductions:			
51	Accum Prov For Deprec	(4,043,129,802)		(4,043,129,802)
52	Accum Prov For Amort	(232,858,605)		(232,858,605)
53	Accum Def Income Tax	(703,568,427)		(703,568,427)
54	Unamortized ITC	(40,918)		(40,918)
55	Customer Adv For Const	(46,658,522)		(46,658,522)
56	Customer Service Deposits	-		-
57	Misc Rate Base Deductions	(433,111,498)		(433,111,498)
58				
59	Total Rate Base Deductions	(5,459,367,773)		(5,459,367,773)
60				
61	Total Rate Base:	5,300,883,073		5,300,883,073
62				
63	Return on Rate Base	5.565%		7.740%
64				
65	Return on Equity	5.951%		10.300%
66				
67	TAX CALCULATION:			
68	Operating Revenue	334,564,486	152,859,118	487,423,604
69	Other Deductions			
70	Interest (AFUDC)	(65,590,851)	-	(65,590,851)
71	Interest	137,265,413	-	137,265,413
72	Schedule "M" Additions	434,539,308	-	434,539,308
73	Schedule "M" Deductions	517,163,102	-	517,163,102
74	Income Before Tax	180,266,131	152,859,118	333,125,249
75				
76	State Income Taxes	8,403,176	6,939,804	15,342,980
77	Taxable Income	171,862,955	145,919,314	317,782,268
78				
79	Federal Income Taxes + Other	36,078,107	30,643,056	66,721,163

PacifiCorp
OREGON
Normalized Results of Operations - 2020 PROTOCOL
Twelve Months Ending December 31, 2025

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	604,412,863	(18,264,624)	586,148,239
3	Interdepartmental	-		-
4	Special Sales	92,078,056		92,078,056
5	Other Operating Revenues	-		-
6	Total Operating Revenues	696,490,919	(18,264,624)	678,226,295
7				
8	Operating Expenses:			
9	Steam Production	147,610,878		147,610,878
10	Nuclear Production	-		-
11	Hydro Production	-		-
12	Other Power Supply	571,959,299		571,959,299
13	Transmission	45,115,602		45,115,602
14	Distribution	-		-
15	Customer Accounting	-	-	-
16	Customer Service & Info	-		-
17	Sales	-		-
18	Administrative & General	-		-
19				
20	Total O&M Expenses	764,685,778	-	764,685,778
21				
22	Depreciation	-		-
23	Amortization	-		-
24	Taxes Other Than Income	-	-	-
25	Income Taxes - Federal	(78,872,787)	(3,661,436)	(82,534,223)
26	Income Taxes - State	(3,096,047)	(829,214)	(3,925,261)
27	Income Taxes - Def Net	-		-
28	Investment Tax Credit Adj.	-		-
29	Misc Revenue & Expense	-		-
30				
31	Total Operating Expenses:	682,716,945	(4,490,650)	678,226,295
32				
33	Operating Rev For Return:	13,773,974	(13,773,974)	-
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	(68,194,859)	(18,264,624)	(86,459,483)
69	Other Deductions			
70	Interest (AFUDC)	-	-	-
71	Interest	-	-	-
72	Schedule "M" Additions	-	-	-
73	Schedule "M" Deductions	-	-	-
74	Income Before Tax	(68,194,859)	(18,264,624)	(86,459,483)
75				
76	State Income Taxes	(3,096,047)	(829,214)	(3,925,261)
77	Taxable Income	(65,098,813)	(17,435,410)	(82,534,223)
78				
79	Federal Income Taxes + Other	(78,872,787)	(3,661,436)	(82,534,223)

PacifiCorp
OREGON
Normalized Results of Operations - 2020 PROTOCOL
Twelve Months Ending December 31, 2025

		(1) Total Adjusted Results	(2) Price Change	(3) Results with Price Change
1	Operating Revenues:			
2	General Business Revenues	1,680,937,338	139,399,195	1,820,336,533
3	Interdepartmental	-		
4	Special Sales	92,078,056		
5	Other Operating Revenues	71,932,639		
6	Total Operating Revenues	1,844,948,033		
7				
8	Operating Expenses:			
9	Steam Production	236,350,339		
10	Nuclear Production	-		
11	Hydro Production	13,610,836		
12	Other Power Supply	602,291,370		
13	Transmission	64,748,998		
14	Distribution	114,708,178		
15	Customer Accounting	31,422,542	872,291	32,294,833
16	Customer Service & Info	5,308,096		
17	Sales	-		
18	Administrative & General	61,612,724		
19				
20	Total O&M Expenses	1,130,053,083		
21				
22	Depreciation	317,077,683		
23	Amortization	30,904,843		
24	Taxes Other Than Income	100,572,803	3,932,410	104,505,214
25	Income Taxes - Federal	(42,794,680)	26,981,620	(15,813,060)
26	Income Taxes - State	5,307,130	6,110,590	11,417,720
27	Income Taxes - Def Net	(4,937,211)		
28	Investment Tax Credit Adj.	-		
29	Misc Revenue & Expense	(30,006)		
30				
31	Total Operating Expenses:	1,536,153,644	37,896,911	1,574,050,555
32				
33	Operating Rev For Return:	308,794,389	101,502,284	410,296,672
34				
35	Rate Base:			
36	Electric Plant In Service	10,425,808,241		
37	Plant Held for Future Use	-		
38	Misc Deferred Debits	101,941,905		
39	Elec Plant Acq Adj	703,248		
40	Pensions	-		
41	Prepayments	16,838,184		
42	Fuel Stock	37,268,548		
43	Material & Supplies	129,822,071		
44	Working Capital	47,868,648		
45	Weatherization Loans	-		
46	Misc Rate Base	-		
47				
48	Total Electric Plant:	10,760,250,845	-	10,760,250,845
49				
50	Rate Base Deductions:			
51	Accum Prov For Deprec	(4,043,129,802)		
52	Accum Prov For Amort	(232,858,605)		
53	Accum Def Income Tax	(703,568,427)		
54	Unamortized ITC	(40,918)		
55	Customer Adv For Const	(46,658,522)		
56	Customer Service Deposits	-		
57	Misc Rate Base Deductions	(433,111,498)		
58				
59	Total Rate Base Deductions	(5,459,367,773)	-	(5,459,367,773)
60				
61	Total Rate Base:	5,300,883,073	-	5,300,883,073
62				
63	Return on Rate Base	5.825%		7.740%
64				
65	Return on Equity	6.470%		10.300%
66				
67	TAX CALCULATION:			
68	Operating Revenue	266,369,627	134,594,493	400,964,120
69	Other Deductions			
70	Interest (AFUDC)	(65,590,851)	-	(65,590,851)
71	Interest	137,265,413	-	137,265,413
72	Schedule "M" Additions	434,539,308	-	434,539,308
73	Schedule "M" Deductions	517,163,102	-	517,163,102
74	Income Before Tax	112,071,272	134,594,493	246,665,765
75				
76	State Income Taxes	5,307,130	6,110,590	11,417,720
77	Taxable Income	106,764,142	128,483,903	235,248,045
78				
79	Federal Income Taxes + Other	(42,794,680)	26,981,620	(15,813,060)

PacifiCorp
OREGON
Normalized Results of Operations - 2020 PROTOCOL
Twelve Months Ending December 31, 2025

Net Rate Base	$	5,300,883,073	Ref. Page 1.1
Return on Rate Base Requested		7.74%	Ref. Page 2.0
Revenues Required to Earn Requested Return		410,296,672	
Less Current Operating Revenues		(308,794,389)	
Increase to Current Revenues		101,502,284	
Net to Gross Bump-up		137.34%	
Price Change Required for Requested Return	$	139,399,195	
Requested Price Change	$	139,399,195	
Uncollectible Percent		0.626%	Ref. Page 1.6
Increased Uncollectible Expense	$	872,291	
Requested Price Change	$	139,399,195	
Franchise Tax		2.276%	Ref. Page 1.6
Revenue Tax		0.000%	Ref. Page 1.6
Resource Supplier Tax		0.115%	Ref. Page 1.6
PUC Fees Based on General Business Revenues		0.430%	Ref. Page 1.6
Increase Taxes Other Than Income	$	3,932,410	
Requested Price Change	$	139,399,195	
Uncollectible Expense		(872,291)	
Taxes Other Than Income		(3,932,410)	
Income Before Taxes	$	134,594,493	
State Effective Tax Rate		4.54%	Ref. Page 2.0
State Income Taxes	$	6,110,590	
Taxable Income	$	128,483,903	
Federal Income Tax Rate		21.00%	Ref. Page 2.0
Federal Income Taxes	$	26,981,620	
Operating Income		100.000%	
Net Operating Income		72.814%	Ref. Page 1.6
Net to Gross Bump-Up		137.34%	

PacifiCorp
OREGON
Normalized Results of Operations - 2020 PROTOCOL
Twelve Months Ending December 31, 2025

Operating Revenue	100.000%	
Operating Deductions		
Uncollectible Accounts	0.626%	See Note (1) Below
Taxes Other - Franchise Tax	2.276%	
Taxes Other - Revenue Tax	0.000%	
Taxes Other - Resource Supplier	0.115%	
PUC Fees Based on General Business Revenues	0.430%	
Sub-Total	96.553%	
State Income Tax @ 4.54%	4.384%	
Sub-Total	92.170%	
Federal Income Tax @ 21.00%	19.356%	
Net Operating Income	72.814%	

(1) Uncollectible Accounts =	10,518,476	Pg 2.11, OREGON Situs from Account 904
	1,680,937,338	Pg. 2.2, General Business Revenues

PacifiCorp
Oregon General Rate Case
Adjustment Summary
Twelve Months Ending December 31, 2025

		TOTAL COMPANY UNADJUSTED RESULTS JUNE 2023	OREGON ALLOCATED UNADJUSTED RESULTS JUNE 2023	Tab 3 Revenue Adjustments	Tab 4 O&M Adjustments	Tab 5 Net Power Cost Adjustments
1	Operating Revenues:					
2	General Business Revenues	5,314,367,832	1,399,023,529	280,144,493	1,769,316	-
3	Interdepartmental	-	-	-	-	-
4	Special Sales	276,874,873	70,586,388	-	-	21,491,668
5	Other Operating Revenues	272,845,382	74,297,451	1,710,577	-	-
6	Total Operating Revenues	5,864,088,087	1,543,907,367	281,855,070	1,769,316	21,491,668
7						
8	Operating Expenses:					
9	Steam Production	929,501,268	246,336,079	-	354,350	(13,786,753)
10	Nuclear Production	-	-	-	-	-
11	Hydro Production	42,657,730	11,468,171	-	2,706,114	-
12	Other Power Supply	1,454,847,175	520,565,938	-	2,671,783	78,154,638
13	Transmission	247,176,958	66,310,208	-	(1,931,955)	370,746
14	Distribution	282,601,391	104,588,448	-	9,263,977	-
15	Customer Accounting	80,792,201	23,991,155	-	7,431,387	-
16	Customer Service & Info	158,979,871	4,916,333	-	391,763	-
17	Sales	-	-	-	-	-
18	Administrative & General	630,431,721	172,101,036	-	(110,837,989)	-
19						
20	Total O&M Expenses	3,826,988,315	1,150,277,368	-	(89,950,571)	64,738,631
21						
22	Depreciation	993,452,379	271,108,388	-	-	-
23	Amortization	76,333,322	15,984,719	-	-	-
24	Taxes Other Than Income	188,692,373	74,630,102	-	6,690,549	-
25	Income Taxes - Federal	(251,536,478)	(73,225,613)	56,491,598	17,957,678	(8,677,947)
26	Income Taxes - State	(2,433,217)	(1,498,603)	12,793,783	4,066,917	(1,965,315)
27	Income Taxes - Def Net	55,172,095	(9,956,034)	-	(1,865,118)	-
28	Investment Tax Credit Adj.	(910,300)	-	-	-	-
29	Misc Revenue & Expense	(396,311)	(50,000)	-	19,995	-
30						
31	Total Operating Expenses:	4,885,362,180	1,427,270,327	69,285,381	(63,080,549)	54,095,369
32						
33	Operating Rev For Return:	978,725,907	116,637,039	212,569,689	64,849,865	(32,603,701)
34						
35	Rate Base:					
36	Electric Plant In Service	32,886,279,146	9,145,444,083	-	-	-
37	Plant Held for Future Use	14,174,575	7,461,409	-	-	-
38	Misc Deferred Debits	1,636,633,742	182,518,703	-	-	-
39	Elec Plant Acq Adj	11,954,169	723,506	-	-	-
40	Pensions	104,951,393	28,783,408	-	-	-
41	Prepayments	96,171,480	16,838,184	-	-	-
42	Fuel Stock	137,605,040	36,243,955	-	-	-
43	Material & Supplies	407,130,439	129,822,071	-	-	-
44	Working Capital	126,195,894	46,667,656	2,072,867	(1,832,030)	1,618,415
45	Weatherization Loans	224,530,257	-	-	-	-
46	Misc Rate Base	-	-	-	-	-
47						
48	Total Electric Plant:	35,645,626,136	9,594,502,976	2,072,867	(1,832,030)	1,618,415
49						
50	Rate Base Deductions:					
51	Accum Prov For Deprec	(11,020,394,328)	(3,223,614,207)	-	-	-
52	Accum Prov For Amort	(731,617,791)	(207,213,607)	-	-	-
53	Accum Def Income Tax	(2,927,745,908)	(674,015,477)	-	(38,564,469)	-
54	Unamortized ITC	(2,260,839)	(45,635)	-	-	-
55	Customer Adv For Const	(193,419,991)	(73,982,464)	-	-	-
56	Customer Service Deposits	-	-	-	-	-
57	Misc Rate Base Deductions	(2,624,994,265)	(610,776,749)	-	156,851,573	-
58						
59	Total Rate Base Deductions	(17,500,433,122)	(4,789,648,140)	-	118,287,105	-
60						
61	Total Rate Base:	18,145,193,015	4,804,854,836	2,072,867	116,455,075	1,618,415
62						
63	Return on Rate Base		2.427%	4.421%	1.155%	-0.665%
64						
65	Return on Equity		-0.325%	8.842%	2.310%	-1.329%
66						
67	TAX CALCULATION:					
68	Operating Revenue		31,956,790	281,855,070	85,009,343	(43,246,962)
69	Other Deductions					
70	Interest (AFUDC)		(27,057,087)	-	-	-
71	Interest		124,420,851	53,677	3,015,583	41,909
72	Schedule "M" Additions		349,040,084	-	7,585,912	-
73	Schedule "M" Deductions		382,368,862	-	-	-
74	Income Before Tax		(98,735,753)	281,801,394	89,579,671	(43,288,871)
75						
76	State Income Taxes		(1,498,603)	12,793,783	4,066,917	(1,965,315)
77	Taxable Income		(97,237,150)	269,007,610	85,512,754	(41,323,556)
78						
79	Federal Income Taxes + Other		(73,225,613)	56,491,598	17,957,678	(8,677,947)
	APPROXIMATE PRICE CHANGE		350,528,448	(291,740,043)	(76,613,297)	44,948,662

PacifiCorp
Oregon General Rate Case
Adjustment Summary
Twelve Months Ending December 31, 2025

		Tab 6	Tab 7	Tab 8	OR Allocated
		Depreciation & Amortization Adjustments	Tax Adjustments	Rate Base Adjustments	Results of Operations December 2025
1	Operating Revenues:				
2	General Business Revenues	-	-	-	1,680,937,338
3	Interdepartmental	-	-	-	-
4	Special Sales	-	-	-	92,078,056
5	Other Operating Revenues	-	-	(4,075,388)	71,932,639
6	Total Operating Revenues	-	-	(4,075,388)	1,844,948,033
7					
8	Operating Expenses:				
9	Steam Production	3,818,882	-	(372,219)	236,350,339
10	Nuclear Production	-	-	-	-
11	Hydro Production	-	-	(563,449)	13,610,836
12	Other Power Supply	-	-	899,010	602,291,370
13	Transmission	-	-	-	64,748,998
14	Distribution	-	-	855,753	114,708,178
15	Customer Accounting	-	-	-	31,422,542
16	Customer Service & Info	-	-	-	5,308,096
17	Sales	-	-	-	-
18	Administrative & General	-	-	349,677	61,612,724
19					
20	Total O&M Expenses	3,818,882	-	1,168,773	1,130,053,083
21					
22	Depreciation	40,255,866	-	5,713,429	317,077,683
23	Amortization	(2,716,107)	-	17,636,230	30,904,843
24	Taxes Other Than Income	-	19,252,152	-	100,572,803
25	Income Taxes - Federal	(3,114,987)	(28,534,545)	(3,690,866)	(42,794,680)
26	Income Taxes - State	(705,458)	(6,548,315)	(835,879)	5,307,130
27	Income Taxes - Def Net	(938,932)	18,161,605	(10,338,733)	(4,937,211)
28	Investment Tax Credit Adj.	-	-	-	-
29	Misc Revenue & Expense	-	-	-	(30,006)
30					
31	Total Operating Expenses:	36,599,264	2,330,897	9,652,955	1,536,153,644
32					
33	Operating Rev For Return:	(36,599,264)	(2,330,897)	(13,728,343)	308,794,389
34					
35	Rate Base:				
36	Electric Plant In Service	-	-	1,280,364,158	10,425,808,241
37	Plant Held for Future Use	-	-	(7,461,409)	-
38	Misc Deferred Debits	-	-	(80,576,798)	101,941,905
39	Elec Plant Acq Adj	-	-	(20,258)	703,248
40	Pensions	-	-	(28,783,408)	-
41	Prepayments	-	-	-	16,838,184
42	Fuel Stock	-	-	1,024,593	37,268,548
43	Material & Supplies	-	-	-	129,822,071
44	Working Capital	(47)	(473,620)	(184,593)	47,868,648
45	Weatherization Loans	-	-	-	-
46	Misc Rate Base	-	-	-	-
47					
48	Total Electric Plant:	(47)	(473,620)	1,164,362,284	10,760,250,845
49					
50	Rate Base Deductions:				
51	Accum Prov For Deprec	(817,609,078)	-	(1,906,517)	(4,043,129,802)
52	Accum Prov For Amort	(25,921,413)	-	276,415	(232,858,605)
53	Accum Def Income Tax	1,988,755	(34,395,710)	41,418,474	(703,568,427)
54	Unamortized ITC	-	4,716	-	(40,918)
55	Customer Adv For Const	-	-	27,323,942	(46,658,522)
56	Customer Service Deposits	-	-	-	-
57	Misc Rate Base Deductions	(8,088,788)	29,710,341	(807,875)	(433,111,498)
58					
59	Total Rate Base Deductions	(849,630,523)	(4,680,653)	66,304,439	(5,459,367,773)
60					
61	Total Rate Base:	(849,630,570)	(5,154,273)	1,230,666,723	5,300,883,073
62					
63	Return on Rate Base	0.632%	-0.047%	-2.099%	5.825%
64					
65	Return on Equity	1.264%	-0.094%	-4.197%	6.470%
66					
67	TAX CALCULATION:				
68	Operating Revenue	(41,358,641)	(19,252,152)	(28,593,820)	266,369,627
69	Other Deductions				
70	Interest (AFUDC)	-	(38,533,764)	-	(65,590,851)
71	Interest	(22,001,031)	(133,469)	31,867,893	137,265,413
72	Schedule "M" Additions	3,818,882	40,628,028	33,466,404	434,539,308
73	Schedule "M" Deductions	-	143,378,120	(8,583,880)	517,163,102
74	Income Before Tax	(15,538,728)	(83,335,010)	(18,411,430)	112,071,272
75					
76	State Income Taxes	(705,458)	(6,548,315)	(835,879)	5,307,130
77	Taxable Income	(14,833,270)	(76,786,695)	(17,575,551)	106,764,142
78					
79	Federal Income Taxes + Other	(3,114,987)	(28,534,545)	(3,690,866)	(42,794,680)
	APPROXIMATE PRICE CHANGE	(40,051,957)	2,653,261	149,674,120	139,399,195

Tab 0 - Results of Operations

PacifiCorp
RESULTS OF OPERATIONS

USER SPECIFIC INFORMATION

STATE:	OREGON
PERIOD:	TWELVE MONTHS ENDING DECEMBER 31, 2025
FILE:	OR JAM Dec 2025 GRC
PREPARED BY:	Revenue Requirement Department
DATE:	2/11/2024
TIME:	10:48:57 AM
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	49.99%	5.18%	2.59%
PREFERRED	0.01%	6.75%	0.00%
COMMON	50.00%	10.30%	5.15%
	100.00%		7.74%

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

RESULTS OF OPERATIONS SUMMARY

			JUNE 2023 UNADJUSTED RESULTS		DECEMBER 2025 NORMALIZED RESULTS	
	Description of Account Summary:	**Ref**	**TOTAL**	**OREGON**	**TOTAL**	**OREGON**
1	Operating Revenues					
2	General Business Revenues	2.2	5,314,367,832	1,399,023,529	5,596,281,641	1,680,937,338
3	Interdepartmental	2.2	0	0	0	0
4	Special Sales	2.2	276,874,873	70,586,388	356,816,632	92,078,056
5	Other Operating Revenues	2.3	272,845,382	74,297,451	275,227,526	71,932,639
6	Total Operating Revenues	2.3	5,864,088,087	1,543,907,367	6,228,325,799	1,844,948,033
7						
8	Operating Expenses:					
9	Steam Production	2.5	929,501,268	246,336,079	891,377,878	236,350,339
10	Nuclear Production	2.5	0	0	0	0
11	Hydro Production	2.6	42,657,730	11,468,171	50,627,720	13,610,836
12	Other Power Supply	2.7, .8	1,454,847,175	520,565,938	1,749,745,636	602,291,370
13	Transmission	2.9	247,176,958	66,310,208	241,086,689	64,748,998
14	Distribution	2.10	282,601,391	104,588,448	297,352,687	114,708,178
15	Customer Accounting	2.11	80,792,201	23,991,155	90,489,557	31,422,542
16	Customer Service & Infor	2.12	158,979,871	4,916,333	158,220,294	5,308,096
17	Sales	2.12	0	0	0	0
18	Administrative & General	2.13	630,431,721	172,101,036	176,796,426	61,612,724
19						
20	Total O & M Expenses	2.13	3,826,988,315	1,150,277,368	3,655,696,887	1,130,053,083
21						
22	Depreciation	2.14	993,452,379	271,108,388	1,182,577,845	317,077,683
23	Amortization	2.15	76,333,322	15,984,719	100,491,871	30,904,843
24	Taxes Other Than Income	2.15	188,692,373	74,630,102	249,331,003	100,572,803
25	Income Taxes - Federal	2.18	(251,536,478)	(73,225,613)	(118,097,100)	(42,794,680)
26	Income Taxes - State	2.18	(2,433,217)	(1,498,603)	35,344,422	5,307,130
27	Income Taxes - Def Net	2.16	55,172,095	(9,956,034)	(115,346,384)	(4,937,211)
28	Investment Tax Credit Adj.	2.15	(910,300)	0	(471,305)	0
29	Misc Revenue & Expense	2.3	(396,311)	(50,000)	(351,090)	(30,006)
30						
31	Total Operating Expenses	2.18	4,885,362,180	1,427,270,327	4,989,176,149	1,536,153,644
32						
33	Operating Revenue for Return		978,725,907	116,637,039	1,239,149,650	308,794,389
34						
35	Rate Base:					
36	Electric Plant in Service	2.26	32,886,279,146	9,145,444,083	38,015,063,522	10,425,808,241
37	Plant Held for Future Use	2.26	14,174,575	7,461,409	0	0
38	Misc Deferred Debits	2.28	1,636,633,742	182,518,703	1,335,815,134	101,941,905
39	Elec Plant Acq Adj	2.26,.27	11,954,169	723,506	11,878,818	703,248
40	Pensions	2.27	104,951,393	28,783,408	0	0
41	Prepayments	2.28	96,171,480	16,838,184	96,171,480	16,838,184
42	Fuel Stock	2.27	137,605,040	36,243,955	141,495,044	37,268,548
43	Material & Supplies	2.28	407,130,439	129,822,071	407,130,439	129,822,071
44	Working Capital	2.28	126,195,894	46,667,656	124,027,742	47,868,648
45	Weatherization Loans	2.27	224,530,257	0	224,530,257	0
46	Miscellaneous Rate Base	2.29	0	0	0	0
47						
48	Total Electric Plant		35,645,626,136	9,594,502,976	40,356,112,435	10,760,250,845
49						
50	Rate Base Deductions:					
51	Accum Prov For Depr	2.32	(11,020,394,328)	(3,223,614,207)	(13,661,526,090)	(4,043,129,802)
52	Accum Prov For Amort	2.33	(731,617,791)	(207,213,607)	(822,620,498)	(232,858,605)
53	Accum Def Income Taxes	2.30	(2,927,745,908)	(674,015,477)	(3,029,320,490)	(703,568,427)
54	Unamortized ITC	2.30	(2,260,839)	(45,635)	(2,074,486)	(40,918)
55	Customer Adv for Const	2.29	(193,419,991)	(73,982,464)	(193,419,991)	(46,658,522)
56	Customer Service Deposits	2.29	0	0	0	0
57	Misc. Rate Base Deductions	2.29	(2,624,994,265)	(610,776,749)	(2,058,185,179)	(433,111,498)
58						
59	Total Rate Base Deductions		(17,500,433,122)	(4,789,648,140)	(19,767,146,734)	(5,459,367,773)
60						
61	Total Rate Base		18,145,193,015	4,804,854,836	20,588,965,700	5,300,883,073
62						
63	Return on Rate Base		5.394%	2.427%	6.019%	5.825%
64						
65	Return on Equity		5.607%	-0.325%	6.857%	6.470%
66	Net Power Costs		2,380,539,065	629,382,892	2,531,355,564	672,607,722
67	100 Basis Points in Equity:		90,725,965	24,024,274	102,944,829	26,504,415
68	Revenue Requirement Impact		120,304,833	31,856,771	136,507,343	35,145,498
69	Rate Base Decrease		(1,539,330,746)	(820,646,040)	(1,579,268,506)	(419,019,707)

2020 PROTOCOL Year End FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2023 UNADJUSTED RESULTS TOTAL	JUNE 2023 UNADJUSTED RESULTS OREGON	DECEMBER 2025 NORMALIZED RESULTS TOTAL	DECEMBER 2025 NORMALIZED RESULTS OREGON
Sales to Ultimate Customers							
440	Residential Sales						
		S		2,192,507,229	726,305,943	2,270,593,606	804,392,320
			B1	2,192,507,229	726,305,943	2,270,593,606	804,392,320
442	Commercial & Industrial Sales						
		S		3,106,997,795	667,790,073	3,312,207,316	872,999,594
		SE		-	-	-	-
		SG		-	-	-	-
			B1	3,106,997,795	667,790,073	3,312,207,316	872,999,594
444	Public Street & Highway Lighting						
		S		14,862,807	4,927,512	13,480,719	3,545,424
		SO		-	-	-	-
			B1	14,862,807	4,927,512	13,480,719	3,545,424
445	Other Sales to Public Authority						
		S		-	-	-	-
			B1	-	-	-	-
448	Interdepartmental						
		S		-	-	-	-
		SO		-	-	-	-
			B1	-	-	-	-
Total Sales to Ultimate Customers			**B1**	**5,314,367,832**	**1,399,023,529**	**5,596,281,641**	**1,680,937,338**
447	Sales for Resale-Non NPC						
		S		14,317,310	-	14,317,310	-
			B1	14,317,310	-	14,317,310	-
447NPC	Sales for Resale-NPC						
		SG		262,557,563	70,586,388	342,499,323	92,078,056
		SE		-	-	-	-
		SG		-	-	-	-
			B1	262,557,563	70,586,388	342,499,323	92,078,056
	Total Sales for Resale		B1	276,874,873	70,586,388	356,816,632	92,078,056
449	Provision for Rate Refund						
		S		-	-	-	-
		SG		-	-	-	-
			B1	-	-	-	-
Total Sales from Electricity			**B1**	**5,591,242,705**	**1,469,609,916**	**5,953,098,274**	**1,773,015,394**
450	Forfeited Discounts & Interest						
		S		12,852,263	5,583,122	12,852,263	5,583,122
		SO		-	-	-	-
			B1	12,852,263	5,583,122	12,852,263	5,583,122
451	Misc Electric Revenue						
		S		7,209,105	1,520,715	7,209,105	1,520,715
		SG		-	-	-	-
		SO		-	-	-	-
			B1	7,209,105	1,520,715	7,209,105	1,520,715
453	Water Sales						
		SG		4,980	1,339	4,980	1,339
			B1	4,980	1,339	4,980	1,339
454	Rent of Electric Property						
		S		12,652,950	5,282,389	12,652,950	5,282,389
		SG		3,696,909	993,883	3,696,909	993,883
		SG		-	-	-	-
		SO		3,363,987	922,589	3,363,987	922,589
			B1	19,713,846	7,198,861	19,713,846	7,198,861

	2020 PROTOCOL Year End FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2023 UNADJUSTED RESULTS TOTAL	JUNE 2023 UNADJUSTED RESULTS OREGON	DECEMBER 2025 NORMALIZED RESULTS TOTAL	DECEMBER 2025 NORMALIZED RESULTS OREGON
144								
145								
146								
147	456	Other Electric Revenue						
148			S		24,404,444	4,075,388	20,329,056	-
149			CN		-	-	-	-
150			SE		32,877,886	8,659,745	37,552,124	9,890,899
151			SO		99,792	27,369	99,792	27,369
152			SG		175,683,066	47,230,912	177,466,360	47,710,335
153								
154								
155				B1	233,065,189	59,993,414	235,447,333	57,628,602
156								
157	**Total Other Electric Revenues**			**B1**	**272,845,382**	**74,297,451**	**275,227,526**	**71,932,639**
158								
159	**Total Electric Operating Revenues**			**B1**	**5,864,088,087**	**1,543,907,367**	**6,228,325,799**	**1,844,948,033**
160								
161	Summary of Revenues by Factor							
162		S			5,385,803,904	1,415,485,143	5,663,642,325	1,693,323,564
163		CN			-	-	-	-
164		SE			32,877,886	8,659,745	37,552,124	9,890,899
165		SO			3,463,779	949,958	3,463,779	949,958
166		SG			441,942,518	118,812,521	523,667,572	140,783,612
167		DGP			-	-	-	-
168								
169	Total Electric Operating Revenues				5,864,088,087	1,543,907,367	6,228,325,799	1,844,948,033
170	Miscellaneous Revenues							
171	41160	Gain on Sale of Utility Plant - CR						
172			S		-	-	-	-
173			SG		-	-	-	-
174			SO		-	-	-	-
175			SG		-	-	-	-
176			SG		-	-	-	-
177				B1	-	-	-	-
178								
179	41170	Loss on Sale of Utility Plant						
180			S		-	-	-	-
181			SG		-	-	-	-
182				B1	-	-	-	-
183								
184	4118	Gain from Emission Allowances						
185			S		-	-	-	-
186			SE		(91)	(24)	(91)	(24)
187				B1	(91)	(24)	(91)	(24)
188								
189	41181	Gain from Disposition of NOX Credits						
190			SE		-	-	-	-
191				B1	-	-	-	-
192								
193	4194	Impact Housing Interest Income						
194			SG		-	-	-	-
195				B1	-	-	-	-
196								
197	421	(Gain) / Loss on Sale of Utility Plant						
198			S		80,910	80,879	59,150	80,879
199			SG		-	-	-	-
200			SG		-	-	-	-
201			CN		-	-	-	-
202			SO		(477,131)	(130,855)	(110,008)	(30,170)
203			SG		-	-	(300,141)	(80,690)
204				B1	(396,221)	(49,977)	(350,999)	(29,982)
205								
206	**Total Miscellaneous Revenues**			**B1**	**(396,311)**	**(50,000)**	**(351,090)**	**(30,006)**
207	Miscellaneous Expenses							
208	4311	Interest on Customer Deposits						
209			S		-	-	-	-
210					-	-	-	-
211	**Total Miscellaneous Expenses**			B1	**-**	**-**	**-**	**-**
212								
213	**Net Misc Revenue and Expense**			**B1**	**(396,311)**	**(50,000)**	**(351,090)**	**(30,006)**
214								

2020 PROTOCOL Year End FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2023 UNADJUSTED RESULTS TOTAL	OREGON	DECEMBER 2025 NORMALIZED RESULTS TOTAL	OREGON
500	Operation Supervision & Engineering						
		SG		14,632,688	3,933,875	15,428,035	4,147,697
		SG		-	-	-	-
		SG		-	-	(1,138)	(306)
			B2	14,632,688	3,933,875	15,426,898	4,147,391
501	Fuel Related-Non NPC						
		S		-	-	-	-
		SE		22,201,079	5,847,569	37,773,978	9,949,333
		SE		-	-	-	-
		SE		-	-	-	-
		SE		-	-	-	-
			B2	22,201,079	5,847,569	37,773,978	9,949,333
501NPC	Fuel Related-NPC						
		S		341,013	-	-	-
		SE		601,557,043	158,444,824	555,009,264	146,184,550
		SE		-	-	-	-
		SE		-	-	-	-
		SE		-	-	-	-
			B2	601,898,056	158,444,824	555,009,264	146,184,550
	Total Fuel Related		B2	624,099,134	164,292,393	592,783,242	156,133,883
502	Steam Expenses						
		SG		78,328,419	21,057,935	82,250,253	22,112,287
		SG		-	-	-	-
		SG		-	-	(2,400)	(645)
			B2	78,328,419	21,057,935	82,247,853	22,111,642
503	Steam From Other Sources-Non-NPC						
		SE		-	-	751	198
			B2	-	-	751	198
503NPC	Steam From Other Sources-NPC						
		SE		11,210,726	2,952,806	5,415,246	1,426,328
			B2	11,210,726	2,952,806	5,415,246	1,426,328
505	Electric Expenses						
		SG		717,972	193,021	752,834	202,393
		SG		-	-	-	-
		SG		-	-	-	-
			B2	717,972	193,021	752,834	202,393
506	Misc. Steam Expense						
		SG		35,643,320	9,582,406	37,572,975	10,101,178
		SG		-	-	(6,878,238)	(1,849,156)
		SE		-	-	5,261,096	1,385,726
			B2	35,643,320	9,582,406	35,955,833	9,637,748
507	Rents						
		SG		(215,297)	(57,881)	(225,712)	(60,681)
		SG		-	-	-	-
		SG		-	-	-	-
			B2	(215,297)	(57,881)	(225,712)	(60,681)
510	Maint Supervision & Engineering						
		SG		5,000,170	1,344,253	5,215,817	1,402,228
		SG		-	-	-	-
		SG		-	-	1,997,238	536,941
			B2	5,000,170	1,344,253	7,213,055	1,939,169
511	Maintenance of Structures						
		SG		22,653,946	6,090,323	23,086,188	6,206,527
		SG		-	-	-	-
		SG		-	-	(3,951)	(1,062)
			B2	22,653,946	6,090,323	23,082,237	6,205,465
512	Maintenance of Boiler Plant						
		SG		86,304,858	23,202,334	87,822,069	23,610,223
		SG		-	-	-	-
		SG		-	-	(11,077,008)	(2,977,960)
			B2	86,304,858	23,202,334	76,745,061	20,632,263
513	Maintenance of Electric Plant						
		SG		36,733,112	9,875,388	37,449,293	10,067,927
		SG		-	-	-	-
		SG		-	-	(81)	(22)
			B2	36,733,112	9,875,388	37,449,212	10,067,905

	2020 PROTOCOL Year End FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2023 UNADJUSTED RESULTS TOTAL	JUNE 2023 UNADJUSTED RESULTS OREGON	DECEMBER 2025 NORMALIZED RESULTS TOTAL	DECEMBER 2025 NORMALIZED RESULTS OREGON
296								
297	514	Maintenance of Misc. Steam Plant						
298			SG		14,392,219	3,869,227	14,538,020	3,908,424
299			SG		-	-	-	-
300			SG		-	-	(6,652)	(1,788)
301				B2	14,392,219	3,869,227	14,531,368	3,906,636
302								
303	**Total Steam Power Generation**			**B2**	**929,501,268**	**246,336,079**	**891,377,878**	**236,350,339**
304	517	Operation Super & Engineering						
305			SG		-	-	-	-
306				B2	-	-	-	-
307								
308	518	Nuclear Fuel Expense						
309			SE		-	-	-	-
310								
311				B2	-	-	-	-
312								
313	519	Coolants and Water						
314			SG		-	-	-	-
315				B2	-	-	-	-
316								
317	520	Steam Expenses						
318			SG		-	-	-	-
319				B2	-	-	-	-
320								
321								
322								
323	523	Electric Expenses						
324			SG		-	-	-	-
325				B2	-	-	-	-
326								
327	524	Misc. Nuclear Expenses						
328			SG		-	-	-	-
329				B2	-	-	-	-
330								
331	528	Maintenance Super & Engineering						
332			SG		-	-	-	-
333				B2	-	-	-	-
334								
335	529	Maintenance of Structures						
336			SG		-	-	-	-
337				B2	-	-	-	-
338								
339	530	Maintenance of Reactor Plant						
340			SG		-	-	-	-
341				B2	-	-	-	-
342								
343	531	Maintenance of Electric Plant						
344			SG		-	-	-	-
345				B2	-	-	-	-
346								
347	532	Maintenance of Misc Nuclear						
348			SG		-	-	-	-
349				B2	-	-	-	-
350								
351	**Total Nuclear Power Generation**			**B2**	**-**	**-**	**-**	**-**
352								
353	535	Operation Super & Engineering						
354			SG		-	-	954,942	256,728
355			SG		-	-	(5,523)	(1,485)
356			SG		-	-	(2,135,002)	(573,977)
357			SG		9,054,832	2,434,315	9,410,904	2,530,042
358			SG		3,422,814	920,195	3,655,777	982,825
359								
360				B2	12,477,645	3,354,510	11,881,099	3,194,133
361								
362	536	Water For Power						
363			SG		-	-	(101)	(27)
364			SG		464,604	124,905	475,356	127,795
365			SG		-	-	-	-
366								
367				B2	464,604	124,905	475,255	127,768
368								
369	537	Hydraulic Expenses						
370			SG		-	-	(163)	(44)
371			SG		4,114,974	1,106,276	4,214,717	1,133,091
372			SG		341,210	91,731	347,624	93,456
373			SG		-	-	(141)	(38)
374				B2	4,456,184	1,198,007	4,562,036	1,226,465

	2020 PROTOCOL Year End FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2023 UNADJUSTED RESULTS TOTAL	OREGON	DECEMBER 2025 NORMALIZED RESULTS TOTAL	OREGON
375								
376	538	Electric Expenses						
377			DGP		-	-	-	-
378			SG		-	-	-	-
379			SG		-	-	-	-
380								
381				B2	-	-	-	-
382								
383	539	Misc. Hydro Expenses						
384			SG		-	-	-	-
385			SG		14,846,760	3,991,426	15,407,804	4,142,258
386			SG		7,957,118	2,139,204	8,290,598	2,228,857
387			SG		-	-	(5,193)	(1,396)
388			SG		-	-	(4,723)	(1,270)
389				B2	22,803,878	6,130,630	23,688,487	6,368,450
390								
391	540	Rents (Hydro Generation)						
392			SG		-	-	-	-
393			SG		1,757,400	472,462	1,790,256	481,295
394			SG		(133,277)	(35,830)	(135,768)	(36,500)
395								
396				B2	1,624,123	436,632	1,654,489	444,795
397								
398	541	Maint Supervision & Engineering						
399			SG		-	-	-	-
400			SG		1,559	419	1,554	418
401			SG		-	-	-	-
402								
403				B2	1,559	419	1,554	418
404								
405	542	Maintenance of Structures						
406			SG		-	-	(47)	(13)
407			SG		733,436	197,178	747,670	201,005
408			SG		21,796	5,860	22,402	6,022
409								
410				B2	755,232	203,038	770,024	207,015
411								
412								
413								
414								
415	543	Maintenance of Dams & Waterways						
416			SG		-	-	-	-
417			SG		930,916	250,269	956,026	257,020
418			SG		505,127	135,799	521,101	140,094
419								
420				B2	1,436,043	386,068	1,477,128	397,113
421								
422	544	Maintenance of Electric Plant						
423			SG		-	-	(205)	(55)
424			SG		1,453,981	390,891	1,494,141	401,687
425			SG		342,943	92,197	356,909	95,952
426								
427				B2	1,796,924	483,088	1,850,844	497,584
428								
429	545	Maintenance of Misc. Hydro Plant						
430			SG		-	-	(792)	(213)
431			SG		-	-	(129)	(35)
432			SG		(7,385,140)	(1,985,433)	-	-
433			SG		3,306,789	889,002	3,343,323	898,824
434			SG		919,889	247,304	924,402	248,518
435								
436				B2	(3,158,461)	(849,126)	4,266,804	1,147,094
437								
438	**Total Hydraulic Power Generation**			**B2**	**42,657,730**	**11,468,171**	**50,627,720**	**13,610,836**
439								
440	546	Operation Super & Engineering						
441			SG		504,693	135,682	526,858	141,641
442			SG		-	-	-	-
443			SG		-	-	(55)	(15)
444				B2	504,693	135,682	526,803	141,627
445								
446	547	Fuel-Non-NPC						
447			SE		-	-	-	-
448			SE		-	-	-	-
449				B2	-	-	-	-
450								
451	547NPC	Fuel-NPC						
452			SE		621,099,417	163,592,113	605,538,818	159,493,589
453			SE		628,119	165,441	628,119	165,441
454				B2	621,727,536	163,757,555	606,166,937	159,659,030

2020 PROTOCOL Year End FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2023 UNADJUSTED RESULTS TOTAL	JUNE 2023 UNADJUSTED RESULTS OREGON	DECEMBER 2025 NORMALIZED RESULTS TOTAL	DECEMBER 2025 NORMALIZED RESULTS OREGON
548	Generation Expense						
		SG		22,741,307	6,113,809	23,805,572	6,399,927
		SG		880,908	236,825	924,837	248,635
		SG		-	-	(1,011)	(272)
			B2	23,622,215	6,350,633	24,729,398	6,648,290
549	Miscellaneous Other						
		S		32,773	32,773	34,441	34,441
		SG		4,121,100	1,107,923	4,348,172	1,168,969
		SG		6,581,094	1,769,272	6,876,363	1,848,652
		SG		-	-	4,432,622	1,191,673
		SG		-	-	-	-
			B2	10,734,968	2,909,968	15,691,598	4,243,736
550	Rents						
		S		374,393	374,393	390,750	390,750
		SG		-	-	-	-
		SG		39,881	10,722	41,623	11,190
		SG		10,639,757	2,860,409	11,104,613	2,985,382
			B2	11,054,031	3,245,524	11,536,987	3,387,322
551	Maint Supervision & Engineering						
		SG		-	-	-	-
			B2	-	-	-	-
552	Maintenance of Structures						
		SG		2,391,894	643,040	2,476,375	665,752
		SG		117,546	31,601	121,746	32,730
		SG		-	-	(698)	(188)
			B2	2,509,439	674,642	2,597,423	698,295
553	Maint of Generation & Electric Plant						
		SG		3,324,363	893,727	3,446,684	926,612
		SG		18,210,283	4,895,681	18,652,715	5,014,625
		SG		292,933	78,753	301,991	81,188
		SG		-	-	1,761,160	473,473
			B2	21,827,579	5,868,161	24,162,550	6,495,898
554	Maintenance of Misc. Other						
		SG		2,200,039	591,462	2,253,635	605,871
		SG		1,773,101	476,683	1,815,492	488,080
		SG		128,767	34,618	133,421	35,869
		SG		-	-	(12)	(3)
			B2	4,101,907	1,102,763	4,202,537	1,129,817
Total Other Power Generation			**B2**	**696,082,368**	**184,044,927**	**689,614,234**	**182,404,015**
555	Purchased Power-Non NPC						
		S		(519,795,484)	-	(519,795,484)	-
				(519,795,484)	-	(519,795,484)	-
555NPC	Purchased Power-NPC						
		S		13,444,000	80,131	(1,482,488)	(1,482,488)
		SE		20,074,007	5,287,317	76,775,318	20,221,942
	Seasonal Contracts	SG		1,207,781,184	324,701,791	1,463,913,536	393,560,814
		DGP		-	-	-	-
				1,241,299,192	330,069,238	1,539,206,367	412,300,269
	Total Purchased Power		B2	721,503,708	330,069,238	1,019,410,883	412,300,269
556	System Control & Load Dispatch						
		SG		2,506,281	673,793	2,622,466	705,028
			B2	2,506,281	673,793	2,622,466	705,028
557	Other Expenses						
		S		11,472,438	7,786,113	11,974,223	8,126,293
		SG		33,440,680	8,990,245	36,281,861	9,754,073
		SGCT		-	-	-	-
		SE		6,158	1,622	6,427	1,693
		SG		-	-	-	-
		TROJP		-	-	-	-
			B2	44,919,276	16,777,980	48,262,511	17,882,058

2020 PROTOCOL

	FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2023 UNADJUSTED RESULTS TOTAL	JUNE 2023 UNADJUSTED RESULTS OREGON	DECEMBER 2025 NORMALIZED RESULTS TOTAL	DECEMBER 2025 NORMALIZED RESULTS OREGON
536								
537	Embedded Cost Differentials							
538		Company Owned Hydro	DGP		-	-	-	-
539		Company Owned Hydro	SG		-	-	-	-
540		Mid-C Contract	MC		-	-	-	-
541		Mid-C Contract	SG		-	-	-	-
542		Existing QF Contracts	S		-	-	-	-
543		Existing QF Contracts	SG		-	-	-	-
544								
545					-	-	-	-
546								
547								
548								
549								
550	2020 Protocol Adjustment							
551		Baseline ECD	S		(10,164,458)	(11,000,000)	(10,164,458)	(11,000,000)
552			S		-	-	-	-
553	2020 Protocol Adjustment				(10,164,458)	(11,000,000)	(10,164,458)	(11,000,000)
554								
555	**Total Other Power Supply**			B2	**758,764,807**	**336,521,011**	**1,060,131,402**	**419,887,355**
556								
557	**Total Production Expense**			B2	**2,427,006,174**	**778,370,189**	**2,691,751,234**	**852,252,545**
558								
559								
560	Summary of Production Expense by Factor							
561		S			(504,295,324)	(2,726,589)	(519,043,014)	(3,931,003)
562		SG			1,654,524,949	444,805,086	1,924,385,231	517,354,748
563		SE			1,276,776,549	336,291,692	1,286,409,018	338,828,800
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				2,427,006,174	778,370,189	2,691,751,234	852,252,545
580	560	Operation Supervision & Engineering						
581			SG		10,930,041	2,938,449	11,510,476	3,094,494
582			SG		-	-	(9,489)	(2,551)
583								
584				B2	10,930,041	2,938,449	11,500,987	3,091,943
585								
586	561	Load Dispatching						
587			SG		18,802,836	5,054,984	19,476,128	5,235,993
588			SG		-	-	(2,197)	(591)
589								
590				B2	18,802,836	5,054,984	19,473,931	5,235,402
591	562	Station Expense						
592			SG		4,696,886	1,262,718	4,856,715	1,305,687
593			SG		-	-	(17)	(5)
594								
595				B2	4,696,886	1,262,718	4,856,697	1,305,682
596								
597	563	Overhead Line Expense						
598			SG		1,777,951	477,987	1,811,690	487,058
599			SG		-	-	(768)	(207)
600								
601				B2	1,777,951	477,987	1,810,922	486,851
602								
603	564	Underground Line Expense						
604			SG		-	-	-	-
605								
606				B2	-	-	-	-
607								
608	565	Transmission of Electricity by Others						
609			SG		-	-	-	-
610			SE		-	-	-	-
611					-	-	-	-
612								
613	565NPC	Transmission of Electricity by Others-NPC						
614			SG		141,048,505	37,919,702	156,108,211	41,968,377
615			SE		25,912,615	6,825,154	11,948,862	3,147,225
616					166,961,120	44,744,856	168,057,073	45,115,602

2020 PROTOCOL Year End FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2023 UNADJUSTED RESULTS TOTAL	JUNE 2023 UNADJUSTED RESULTS OREGON	DECEMBER 2025 NORMALIZED RESULTS TOTAL	DECEMBER 2025 NORMALIZED RESULTS OREGON
	Total Transmission of Electricity by		B2	166,961,120	44,744,856	168,057,073	45,115,602
566	Misc. Transmission Expense						
		SG		3,977,554	1,069,332	3,985,654	1,071,510
		SG		-	-	(225)	(61)
			B2	3,977,554	1,069,332	3,985,429	1,071,449
567	Rents - Transmission						
		SG		2,369,571	637,039	2,377,608	639,200
		SG		-	-	-	-
			B2	2,369,571	637,039	2,377,608	639,200
568	Maint Supervision & Engineering						
		SG		1,287,165	346,044	1,377,055	370,210
		SG		-	-	(1,413)	(380)
			B2	1,287,165	346,044	1,375,641	369,830
569	Maintenance of Structures						
		SG		6,226,385	1,673,911	6,309,069	1,696,140
		SG		-	-	(15)	(4)
			B2	6,226,385	1,673,911	6,309,055	1,696,136
570	Maintenance of Station Equipment						
		SG		14,058,332	3,779,464	14,329,474	3,852,358
		SG		-	-	(921)	(248)
			B2	14,058,332	3,779,464	14,328,553	3,852,111
571	Maintenance of Overhead Lines						
		SG		15,825,442	4,254,537	15,597,878	4,193,358
		SG		-	-	(8,847,338)	(2,378,532)
			B2	15,825,442	4,254,537	6,750,540	1,814,826
572	Maintenance of Underground Lines						
		SG		165,378	44,461	165,263	44,430
		SG		-	-	(88)	(24)
			B2	165,378	44,461	165,176	44,406
573	Maint of Misc. Transmission Plant						
		SG		98,296	26,426	95,077	25,561
		SG		-	-	-	-
			B2	98,296	26,426	95,077	25,561
Total Transmission Expense			**B2**	**247,176,958**	**66,310,208**	**241,086,689**	**64,748,998**
Summary of Transmission Expense by Factor							
	SE			25,912,615	6,825,154	11,948,862	3,147,225
	SG			221,264,343	59,485,053	229,137,827	61,601,773
	SNPT			-	-	-	-
Total Transmission Expense by Factor				247,176,958	66,310,208	241,086,689	64,748,998
580	Operation Supervision & Engineering						
		S		3,512,365	1,405,980	3,692,176	1,483,689
		SNPD		14,628,141	3,656,802	15,194,072	3,798,276
			B2	18,140,506	5,062,782	18,886,248	5,281,965
581	Load Dispatching						
		S		-	-	-	-
		SNPD		16,273,116	4,068,020	17,170,832	4,292,434
			B2	16,273,116	4,068,020	17,170,832	4,292,434
582	Station Expense						
		S		5,218,862	1,100,166	5,416,401	1,137,499
		SNPD		501	125	523	131
			B2	5,219,363	1,100,291	5,416,924	1,137,630
583	Overhead Line Expenses						
		S		11,094,040	2,484,502	11,683,192	2,684,199
		SNPD		-	-	-	-
			B2	11,094,040	2,484,502	11,683,192	2,684,199
584	Underground Line Expense						
		S		-	-	-	-
		SNPD		-	-	-	-
			B2	-	-	-	-

2020 PROTOCOL Year End FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2023 UNADJUSTED RESULTS TOTAL	OREGON	DECEMBER 2025 NORMALIZED RESULTS TOTAL	OREGON
585	Street Lighting & Signal Systems						
		S		-	-	-	-
		SNPD		285,897	71,470	300,587	75,142
			B2	285,897	71,470	300,587	75,142
586	Meter Expenses						
		S		2,702,247	1,323,961	2,832,242	1,388,283
		SNPD		-	-	-	-
			B2	2,702,247	1,323,961	2,832,242	1,388,283
587	Customer Installation Expenses						
		S		21,049,798	7,224,789	22,017,679	7,565,964
		SNPD		-	-	-	-
			B2	21,049,798	7,224,789	22,017,679	7,565,964
588	Misc. Distribution Expenses						
		S		1,942,316	(292,109)	2,025,487	(296,944)
		SNPD		132,294	33,071	730,508	182,615
			B2	2,074,610	(259,038)	2,755,994	(114,329)
589	Rents						
		S		2,858,365	1,830,561	2,934,066	1,871,412
		SNPD		396,486	99,115	404,913	101,222
			B2	3,254,851	1,929,676	3,338,979	1,972,634
590	Maint Supervision & Engineering						
		S		(5,277,012)	990,143	(4,820,162)	1,028,357
		SNPD		3,218,427	804,555	3,344,544	836,083
			B2	(2,058,586)	1,794,698	(1,475,618)	1,864,440
591	Maintenance of Structures						
		S		2,065,590	689,375	1,974,450	658,957
		SNPD		83,550	20,886	80,147	20,036
			B2	2,149,140	710,261	2,054,598	678,993
592	Maintenance of Station Equipment						
		S		9,115,374	3,274,403	10,219,978	4,224,901
		SNPD		956,139	239,019	1,163,152	290,770
			B2	10,071,512	3,513,422	11,383,130	4,515,671
593	Maintenance of Overhead Lines						
		S		138,967,405	62,571,152	147,712,516	70,302,494
		SNPD		3,289,392	822,296	3,371,129	842,729
			B2	142,256,797	63,393,448	151,083,645	71,145,222
594	Maintenance of Underground Lines						
		S		40,345,598	9,370,272	40,311,654	9,446,513
		SNPD		9,382	2,345	9,688	2,422
			B2	40,354,980	9,372,617	40,321,342	9,448,935
595	Maintenance of Line Transformers						
		S		-	-	447	-
		SNPD		1,056,734	264,167	1,088,942	272,218
			B2	1,056,734	264,167	1,089,388	272,218
596	Maint of Street Lighting & Signal Sys.						
		S		2,351,219	773,084	2,361,056	790,355
		SNPD		-	-	-	-
			B2	2,351,219	773,084	2,361,056	790,355
597	Maintenance of Meters						
		S		589,900	172,264	607,961	178,506
		SNPD		(28,761)	(7,190)	(25,925)	(6,481)
			B2	561,140	165,075	582,036	172,025
598	Maint of Misc. Distribution Plant						
		S		2,164,554	695,412	2,073,583	667,240
		SNPD		3,599,473	899,811	3,476,848	869,157
			B2	5,764,027	1,595,223	5,550,431	1,536,397
Total Distribution Expense			**B2**	**282,601,391**	**104,588,448**	**297,352,687**	**114,708,178**
Summary of Distribution Expense by Factor							
	S			238,700,620	93,613,955	251,042,727	103,131,426
	SNPD			43,900,772	10,974,493	46,309,960	11,576,752
Total Distribution Expense by Factor				282,601,391	104,588,448	297,352,687	114,708,178

Line	2020 PROTOCOL Year End FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2023 UNADJUSTED RESULTS TOTAL	JUNE 2023 UNADJUSTED RESULTS OREGON	DECEMBER 2025 NORMALIZED RESULTS TOTAL	DECEMBER 2025 NORMALIZED RESULTS OREGON
778	901	Supervision						
779			S		466	-	478	-
780			CN		2,982,177	915,693	3,123,097	958,963
781				B2	2,982,643	915,693	3,123,575	958,963
782								
783	902	Meter Reading Expense						
784			S		11,178,872	2,002,181	11,708,657	2,093,427
785			CN		730,563	224,323	765,168	234,949
786				B2	11,909,435	2,226,504	12,473,825	2,328,376
787								
788	903	Customer Receipts & Collections						
789			S		3,024,082	593,394	7,956,655	5,419,367
790			CN		38,925,598	11,952,312	40,662,839	12,485,741
791				B2	41,949,680	12,545,706	48,619,494	17,905,108
792								
793	904	Uncollectible Accounts						
794			S		24,866,225	8,584,525	27,211,586	10,518,476
795			SG		-	-	-	-
796			CN		(916,184)	(281,319)	(939,334)	(288,428)
797				B2	23,950,041	8,303,206	26,272,252	10,230,048
798								
799	905	Misc. Customer Accounts Expense						
800			S		252	(0)	258	(0)
801			CN		150	46	154	47
802				B2	402	46	412	47
803								
804	**Total Customer Accounts Expense**			**B2**	**80,792,201**	**23,991,155**	**90,489,557**	**31,422,542**
805								
806	Summary of Customer Accts Exp by Factor							
807		S			39,069,897	11,180,100	46,877,634	18,031,270
808		CN			41,722,304	12,811,055	43,611,923	13,391,273
809		SG			-	-	-	-
810	Total Customer Accounts Expense by Factor				80,792,201	23,991,155	90,489,557	31,422,542
811								
812	907	Supervision						
813			S		-	-	-	-
814			CN		1,296	398	1,285	395
815				B2	1,296	398	1,285	395
816								
817	908	Customer Assistance						
818			S		150,123,937	2,368,113	149,212,199	2,480,719
819			CN		3,216,804	987,737	3,370,436	1,034,910
820								
821								
822				B2	153,340,741	3,355,850	152,582,635	3,515,629
823								
824	909	Informational & Instructional Adv						
825			S		2,050,555	458,592	2,458,942	816,425
826			CN		3,578,273	1,098,728	3,168,504	972,906
827				B2	5,628,828	1,557,320	5,627,446	1,789,331
828								
829	910	Misc. Customer Service						
830			S		-	-	-	-
831			CN		9,005	2,765	8,927	2,741
832								
833				B2	9,005	2,765	8,927	2,741
834								
835	**Total Customer Service Expense**			**B2**	**158,979,871**	**4,916,333**	**158,220,294**	**5,308,096**
836								
837								
838	Summary of Customer Service Exp by Factor							
839		S			152,174,492	2,826,705	151,671,140	3,297,144
840		CN			6,805,379	2,089,628	6,549,153	2,010,952
841								
842	Total Customer Service Expense by Factor			B2	158,979,871	4,916,333	158,220,294	5,308,096
843								
844								
845	911	Supervision						
846			S		-	-	-	-
847			CN		-	-	-	-
848				B2	-	-	-	-
849								
850	912	Demonstration & Selling Expense						
851			S		-	-	-	-
852			CN		-	-	-	-
853				B2	-	-	-	-
854								
855	913	Advertising Expense						
856			S		-	-	-	-
857			CN		-	-	-	-
858				B2	-	-	-	-

2020 PROTOCOL Year End FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2023 UNADJUSTED RESULTS TOTAL	OREGON	DECEMBER 2025 NORMALIZED RESULTS TOTAL	OREGON
916	Misc. Sales Expense						
		S		-	-	-	-
		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**	**158,979,871**	**4,916,333**	**158,220,294**	**5,308,096**
920	Administrative & General Salaries						
		S		(615,775)	(615,850)	91,768	91,689
		CN		-	-	-	-
		SO		81,072,180	22,234,423	85,534,056	23,458,113
			B2	80,456,405	21,618,573	85,625,824	23,549,802
921	Office Supplies & expenses						
		S		536,549	(4,518)	544,379	(4,584)
		CN		130,985	40,220	132,896	40,807
		SO		16,883,123	4,630,275	18,488,173	5,070,467
			B2	17,550,657	4,665,977	19,165,448	5,106,690
922	A&G Expenses Transferred						
		S		-	-	-	-
		CN		-	-	-	-
		SO		(48,437,529)	(13,284,218)	(51,107,587)	(14,016,494)
			B2	(48,437,529)	(13,284,218)	(51,107,587)	(14,016,494)
923	Outside Services						
		S		3,070,939	817,809	3,013,143	865,859
		CN		-	-	-	-
		SO		49,301,782	13,521,243	52,198,500	14,315,682
			B2	52,372,720	14,339,052	55,211,643	15,181,541
924	Property Insurance						
		S		14,501,986	10,486,751	19,789,014	15,773,778
		SG		-	-	-	-
		SO		5,049,524	1,384,855	4,804,432	1,317,638
			B2	19,551,510	11,871,606	24,593,446	17,091,416
925	Injuries & Damages						
		S		(8,898,109)	(8,898,109)	3,960,968	3,960,968
		SO		465,818,221	127,752,817	16,101,277	4,415,850
			B2	456,920,112	118,854,708	20,062,246	8,376,819
926	Employee Pensions & Benefits						
		S		(13,736,530)	(5,733,248)	(13,736,530)	(5,733,248)
		SG		-	-	2,967,013	797,657
		SO		144,270,988	39,566,990	113,525,375	31,134,863
			B2	130,534,458	33,833,743	102,755,859	26,199,272
927	Franchise Requirements						
		S		-	-	-	-
		SO		-	-	-	-
			B2	-	-	-	-
928	Regulatory Commission Expense						
		S		19,215,001	6,788,165	20,818,785	8,126,600
		SE		-	-	-	-
		SO		1,691,665	463,947	1,732,403	475,120
		SG		6,382,311	1,715,831	6,510,573	1,750,313
			B2	27,288,977	8,967,942	29,061,761	10,352,032
929	Duplicate Charges						
		S		-	-	-	-
		SO		(135,237,887)	(37,089,620)	(136,113,103)	(37,329,652)
			B2	(135,237,887)	(37,089,620)	(136,113,103)	(37,329,652)
930	Misc General Expenses						
		S		119,844	40	(911,330)	(1,024,126)
		CN		-	-	-	-
		SG		-	-	-	-
		SO		2,719,242	745,765	1,969,384	540,113
			B2	2,839,086	745,805	1,058,053	(484,014)

2020 PROTOCOL Year End FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2023 UNADJUSTED RESULTS TOTAL	 OREGON	DECEMBER 2025 NORMALIZED RESULTS TOTAL	 OREGON
931	Rents						
		S		372,803	282,800	429,409	333,350
		SO		(4,051,577)	(1,111,164)	(4,324,191)	(1,185,930)
			B2	(3,678,774)	(828,364)	(3,894,782)	(852,579)
935	Maintenance of General Plant						
		S		658,849	283,117	664,855	287,854
		CN		35,808	10,995	35,783	10,987
		SO		29,577,330	8,111,720	29,676,980	8,139,050
			B2	30,271,987	8,405,832	30,377,618	8,437,891
Total Administrative & General Expense			**B2**	**630,431,721**	**172,101,036**	**176,796,426**	**61,612,724**
Summary of A&G Expense by Factor							
	S			15,225,557	3,406,956	34,664,461	22,678,140
	SE			-	-	-	-
	SO			608,657,061	166,927,034	132,485,700	36,334,820
	SG			6,382,311	1,715,831	9,477,586	2,547,969
	CN			166,793	51,215	168,680	51,794
Total A&G Expense by Factor				630,431,721	172,101,036	176,796,426	61,612,724
Total O&M Expense			**B2**	**3,826,988,315**	**1,150,277,368**	**3,655,696,887**	**1,130,053,083**
403SP	Steam Depreciation						
		S		(6,748,935)	-	-	-
		SG		50,674,954	13,623,534	50,674,954	13,623,534
		SG		37,646,705	10,120,999	37,646,705	10,120,999
		SG		264,110,600	71,003,909	333,027,444	89,531,621
		SG		-	-	-	-
			B3	345,683,324	94,748,442	421,349,103	113,276,155
403NP	Nuclear Depreciation						
		SG		-	-	-	-
			B3	-	-	-	-
403HP	Hydro Depreciation						
		SG		15,346,394	4,125,749	15,346,394	4,125,749
		SG		1,316,807	354,012	1,316,807	354,012
		SG		6,840,910	1,839,121	20,657,435	5,553,577
		SG		7,852,010	2,110,947	9,365,259	2,517,771
		SG		-	-	(11,378,816)	(3,059,099)
			B3	31,356,121	8,429,829	35,307,079	9,492,011
403OP	Other Production Depreciation						
		S		20,057	158	61,373	61,373
		SG		-	-	-	-
		SG		70,324,552	18,906,163	68,630,208	18,450,653
		SG		4,283,251	1,151,516	4,283,251	1,151,516
		SG		143,905,228	38,687,707	162,327,029	43,640,253
			B3	218,533,087	58,745,544	235,301,861	63,303,795
403TP	Transmission Depreciation						
		SG		8,251,666	2,218,391	8,251,666	2,218,391
		SG		10,327,742	2,776,526	10,327,742	2,776,526
		SG		119,677,406	32,174,262	175,171,380	47,093,349
			B3	138,256,814	37,169,179	193,750,789	52,088,266
403	Distribution Depreciation						
360	Land & Land Rights	S		527,771	73,474	776,301	105,224
361	Structures	S		2,505,872	536,738	2,982,636	597,644
362	Station Equipment	S		28,350,042	6,619,129	32,351,083	7,130,257
363	Storage Battery Equipment	S		-	-	-	-
364	Poles & Towers	S		50,494,099	15,832,720	55,419,647	16,461,953
365	OH Conductors	S		21,939,011	6,641,320	25,024,376	7,035,472
366	UG Conduit	S		10,562,254	2,050,935	12,128,676	2,251,044
367	UG Conductor	S		21,317,741	4,541,656	24,885,594	4,997,445
368	Line Trans	S		37,750,189	12,032,100	42,958,819	12,697,496
369	Services	S		22,690,906	7,207,686	26,013,657	7,632,164
370	Meters	S		11,606,860	1,778,223	12,549,381	1,898,629
371	Inst Cust Prem	S		459,676	116,012	488,167	119,651
372	Leased Property	S		-	-	-	-
373	Street Lighting	S		2,253,019	617,732	2,455,928	643,654
			B3	210,457,441	58,047,724	238,034,265	61,570,633

2020 PROTOCOL Year End FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2023 UNADJUSTED RESULTS TOTAL	 OREGON	DECEMBER 2025 NORMALIZED RESULTS TOTAL	 OREGON
403GP	General Depreciation						
		S		16,547,470	5,055,867	18,865,645	6,424,180
		SG		6,539	1,758	6,539	1,758
		SG		34,736	9,338	34,736	9,338
		SE		112,428	29,613	112,819	29,716
		CN		872,675	267,960	709,753	217,934
		SG		11,268,948	3,029,562	11,241,590	3,022,207
		SO		20,313,717	5,571,131	27,854,589	7,639,251
		SG		9,078	2,441	9,078	2,441
		SG		-	-	-	-
			B3	49,165,591	13,967,669	58,834,749	17,346,823
403GV0	General Vehicles						
		SG		-	-	-	-
			B3	-	-	-	-
403MP	Mining Depreciation						
		SE		-	-	-	-
			B3	-	-	-	-
403EP	Experimental Plant Depreciation						
		SG		-	-	-	-
		SG		-	-	-	-
			B3	-	-	-	-
4031	ARO Depreciation						
		S		-	-	-	-
			B3	-	-	-	-
Total Depreciation Expense			**B3**	**993,452,379**	**271,108,388**	**1,182,577,845**	**317,077,683**
Summary	S			227,024,968	63,103,749	256,961,283	68,056,186
	DGP			-	-	-	-
	DGU			-	-	-	-
	SG			751,877,526	202,135,935	896,939,401	241,134,597
	SO			20,313,717	5,571,131	27,854,589	7,639,251
	CN			872,675	267,960	709,753	217,934
	SE			112,428	29,613	112,819	29,716
	SSGCH			-	-	-	-
	SSGCT			-	-	-	-
Total Depreciation Expense By Factor				1,000,201,315	271,108,388	1,182,577,845	317,077,683
404GP	Amort of LT Plant - Leasehold Improvements						
		S		384,033	145,001	420,872	139,579
		SG		-	-	-	-
		SO		159,654	43,786	41,363	11,344
		SG		-	-	-	-
		CN		-	-	-	-
		SG		-	-	-	-
			B4	543,687	188,787	462,235	150,923
404SP	Amort of LT Plant - Cap Lease Steam						
		SG		-	-	-	-
		SG		-	-	-	-
			B4	-	-	-	-
404IP	Amort of LT Plant - Intangible Plant						
		S		2,435,497	11,336	176,508	11,216
		SE		1,821	480	942	248
		SG		13,211,793	3,551,879	5,812,970	1,562,768
		SO		28,903,296	7,926,864	51,096,692	14,013,506
		CN		15,686,362	4,816,581	15,585,835	4,785,713
		SG		2,697,182	725,115	2,680,531	720,638
		SG		324,280	87,180	314,627	84,585
		SG		78,646	21,143	78,646	21,143
		SG		-	-	-	-
		SG		-	-	-	-
		SG		12,470	3,353	12,470	3,353
			B4	63,351,348	17,143,930	75,759,221	21,203,170
404MP	Amort of LT Plant - Mining Plant						
		SE		-	-	-	-
			B4	-	-	-	-
404OP	Amort of LT Plant - Other Plant						
		S		59,650	59,650	70,641	70,641
			B4	59,650	59,650	70,641	70,641

	2020 PROTOCOL Year End FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2023 UNADJUSTED RESULTS TOTAL	OREGON	DECEMBER 2025 NORMALIZED RESULTS TOTAL	OREGON
1093	404HP	Amortization of Other Electric Plant						
1094			SG		313,582	84,304	313,878	84,383
1095			SG		-	-	-	-
1096			SG		-	-	-	-
1097				B4	313,582	84,304	313,878	84,383
1098								
1099	**Total Amortization of Limited Term Plant**			**B4**	**64,268,267**	**17,476,671**	**76,605,976**	**21,509,117**
1100								
1101								
1102	405	Amortization of Other Electric Plant						
1103			S		-	-	-	-
1104								
1105				B4	-	-	-	-
1106								
1107	406	Amortization of Plant Acquisition Adj						
1108			S		301,635	-	301,635	-
1109			SG		-	-	-	-
1110			SG		-	-	-	-
1111			SG		75,351	20,258	75,351	20,258
1112			SO		-	-	-	-
1113				B4	376,987	20,258	376,987	20,258
1114	407	Amort of Prop Losses, Unrec Plant, etc						
1115			S		11,031,016	(1,688,853)	21,575,576	8,855,708
1116			SO		-	-	-	-
1117			SG-P		-	-	-	-
1118			SE		-	-	-	-
1119			SG		657,053	176,643	1,933,332	519,760
1120			TROJP		-	-	-	-
1121				B4	11,688,069	(1,512,209)	23,508,908	9,375,468
1122								
1123	**Total Amortization Expense**			**B4**	**76,333,322**	**15,984,719**	**100,491,871**	**30,904,843**
1124								
1125								
1126								
1127	Summary of Amortization Expense by Factor							
1128		S			14,211,832	(1,472,865)	22,545,233	9,077,143
1129		SE			1,821	480	942	248
1130		TROJP			-	-	-	-
1131		DGP			-	-	-	-
1132		DGU			-	-	-	-
1133		SO			29,062,950	7,970,650	51,138,056	14,024,850
1134		SSGCT			-	-	-	-
1135		SSGCH			-	-	-	-
1136		CN			15,686,362	4,816,581	15,585,835	4,785,713
1137		SG			17,370,357	4,669,874	11,221,805	3,016,888
1138	Total Amortization Expense by Factor				76,333,322	15,984,719	100,491,871	30,904,843
1139	408	Taxes Other Than Income						
1140			S		36,312,799	32,862,927	49,158,348	45,708,476
1141			GPS		133,792,985	36,693,349	179,679,000	49,277,803
1142			SO		15,434,449	4,232,970	15,434,449	4,232,970
1143			SE		1,205,427	317,499	1,205,427	317,499
1144			SG		1,946,713	523,357	3,853,778	1,036,056
1145			OPRV-ID		-	-	-	-
1146			EXCTAX		-	-	-	-
1147			SG		-	-	-	-
1148								
1149								
1150								
1151	**Total Taxes Other Than Income**			**B5**	**188,692,373**	**74,630,102**	**249,331,003**	**100,572,803**
1152								
1153								
1154	41140	Deferred Investment Tax Credit - Fed						
1155			DGU		(910,300)	-	(471,305)	-
1156								
1157				B7	(910,300)	-	(471,305)	-
1158								
1159	41141	Deferred Investment Tax Credit - Idaho						
1160			DGU		-	-	-	-
1161								
1162				B7	-	-	-	-
1163								
1164	**Total Deferred ITC**			**B7**	**(910,300)**	**-**	**(471,305)**	**-**
1165								
1166								
1167	427	Interest on Long-Term Debt						
1168			S		460,318,292	127,339,341	523,726,055	140,183,903
1169			SNP		-	-	-	-
1170				B6	460,318,292	127,339,341	523,726,055	140,183,903

	2020 PROTOCOL Year End FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2023 UNADJUSTED RESULTS TOTAL	JUNE 2023 UNADJUSTED RESULTS OREGON	DECEMBER 2025 NORMALIZED RESULTS TOTAL	DECEMBER 2025 NORMALIZED RESULTS OREGON
1171								
1172	428	Amortization of Debt Disc & Exp						
1173			SNP		5,081,412	1,328,071	5,081,412	1,328,071
1174				B6	5,081,412	1,328,071	5,081,412	1,328,071
1175								
1176	429	Amortization of Premium on Debt						
1177			SNP		(1,586)	(414)	(1,586)	(414)
1178				B6	(1,586)	(414)	(1,586)	(414)
1179								
1180	431	Other Interest Expense						
1181			OTH		-	-	-	-
1182			SO		-	-	-	-
1183			SNP		31,270,786	8,172,894	31,270,786	8,172,894
1184				B6	31,270,786	8,172,894	31,270,786	8,172,894
1185								
1186	432	AFUDC - Borrowed						
1187			SNP		(47,517,217)	(12,419,040)	(47,517,217)	(12,419,040)
1188					(47,517,217)	(12,419,040)	(47,517,217)	(12,419,040)
1189								
1190		Total Elec. Interest Deductions for		B6	449,151,688	124,420,851	512,559,451	137,265,413
1191								
1192		Non-Regulated Portion of Interest						
1193		427	NUTIL		-	-	-	-
1194		428	NUTIL		-	-	-	-
1195		429	NUTIL		-	-	-	-
1196		431	NUTIL		-	-	-	-
1197								
1198		Total Non-Regulated Interest			-	-	-	-
1199								
1200		Total Interest Deductions for Tax		B6	449,151,688	124,420,851	512,559,451	137,265,413
1201								
1202								
1203	419	Interest & Dividends						
1204			S		-	-	-	-
1205			SNP		(103,524,703)	(27,057,087)	(250,960,991)	(65,590,851)
1206		Total Operating Deductions for Ta›		B6	(103,524,703)	(27,057,087)	(250,960,991)	(65,590,851)
1207								
1208								
1209	41010	Deferred Income Tax - Federal-DR						
1210			S		85,748,550	943,583	(64,081,735)	(309,582)
1211			TROJD		-	-	-	-
1212			SG		-	-	-	-
1213			SO		(74,383,696)	(20,400,075)	650,554	178,417
1214			SNP		37,136,073	9,705,838	89,739,890	23,454,306
1215			SE		6,569,304	1,730,297	15,953	4,202
1216			SG		41,768,328	11,229,063	38,296,680	10,295,739
1217			GPS		32,060,721	8,792,802	11,476,602	3,147,512
1218			DITEXP		-	-	-	-
1219			BADDEBT		-	-	-	-
1220			CN		-	-	-	-
1221			IBT		-	-	-	-
1222			CIAC		-	-	-	-
1223			SCHMDEXP		-	-	-	-
1224			TAXDEPR		310,976,044	81,771,172	343,555,998	90,338,073
1225			SNPD		10,833	2,708	-	-
1226				B7	439,886,157	93,775,388	419,653,942	127,108,667
1227								
1228								
1229								
1230	41110	Deferred Income Tax - Federal-CR						
1231			S		(44,348,109)	(13,059,103)	(104,465,478)	(17,534,021)
1232			SE		(2,657,283)	(699,905)	(3,658,320)	(963,569)
1233			SG		-	-	-	-
1234			SNP		(22,395,044)	(5,853,141)	(53,328,696)	(13,937,921)
1235			SG		(7,189,068)	(1,932,720)	(54,437,149)	(14,634,969)
1236			GPS		392,216	107,567	-	-
1237			SO		(5,695,937)	(1,562,137)	(13,905,339)	(3,813,604)
1238			SNPD		(649,785)	(162,436)	-	-
1239			BADDEBT		(1,347,818)	(524,822)	(0)	(0)
1240			SG		-	-	-	-
1241			SG		-	-	-	-
1242			TROJD		91,374	24,476	-	-
1243			CN		-	-	21,827	6,702
1244			CIAC		(33,807,601)	(8,451,362)	(36,950,197)	(9,236,961)
1245			SCHMDEXP		(267,107,007)	(71,617,840)	(268,276,974)	(71,931,536)
1246			TAXDEPR		-	-	-	-
1247				B7	(384,714,062)	(103,731,422)	(535,000,325)	(132,045,879)
1248								
1249	**Total Deferred Income Taxes**			**B7**	**55,172,095**	**(9,956,034)**	**(115,346,384)**	**(4,937,211)**

	2020 PROTOCOL Year End FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2023 UNADJUSTED RESULTS TOTAL	JUNE 2023 UNADJUSTED RESULTS OREGON	DECEMBER 2025 NORMALIZED RESULTS TOTAL	DECEMBER 2025 NORMALIZED RESULTS OREGON
1250	SCHMAF	Additions - Flow Through						
1251			S		-	-	-	-
1252			SNP		-	-	-	-
1253			SO		-	-	-	-
1254			SE		-	-	-	-
1255			TROJP		-	-	-	-
1256			SG		-	-	-	-
1257				B6	-	-	-	-
1258								
1259	SCHMAP	Additions - Permanent						
1260			S		-	-	-	-
1261			SE		2,679	706	15,008	3,953
1262			SNP		-	-	-	-
1263			SO		2,637,495	723,345	1,897,410	520,374
1264			SG		-	-	-	-
1265			SCHMDEXP		153,260	41,093	131,219	35,183
1266				B6	2,793,433	765,143	2,043,637	559,509
1267								
1268	SCHMAT	Additions - Temporary						
1269			S		(259,221,280)	(11,508,475)	(349,792)	21,050,906
1270			SG		-	-	-	-
1271			CIAC		137,504,173	34,373,852	150,285,917	37,569,085
1272			SNP		91,086,380	23,806,223	216,901,464	56,689,096
1273			TROJD		(371,643)	(99,551)	-	-
1274			SG		-	-	-	-
1275			SE		10,807,854	2,846,694	14,879,342	3,919,087
1276			SG		(1,552,200)	(417,296)	41,982,385	11,286,610
1277			GPS		(1,595,245)	(437,503)	-	-
1278			SO		20,519,774	5,627,644	39,847,239	10,928,291
1279			SNPD		2,642,844	660,669	-	-
1280			BADDEBT		5,481,922	2,134,584	0	0
1281			CN		-	-	(88,778)	(27,260)
1282			SCHMDEXP		1,086,392,617	291,288,100	1,091,151,172	292,563,984
1283				B6	1,091,695,197	348,274,940	1,554,608,949	433,979,799
1284								
1285	TOTAL SCHEDULE - M ADDITIONS			B6	1,094,488,630	349,040,084	1,556,652,586	434,539,308
1286								
1287	SCHMDF	Deductions - Flow Through						
1288			S		-	-	-	-
1289			DGP		-	-	-	-
1290			DGU		-	-	-	-
1291				B6	-	-	-	-
1292	SCHMDP	Deductions - Permanent						
1293			S		-	-	-	-
1294			SE		3,532,967	930,552	574,764	151,388
1295			SNP		113,981	29,790	107,935	28,210
1296			SCHMDEXP		-	-	-	-
1297			SG		-	-	-	-
1298			SO		-	-	-	-
1299				B6	3,646,948	960,342	682,699	179,597
1300								
1301	SCHMDT	Deductions - Temporary						
1302			S		348,761,317	3,837,789	(260,636,824)	(1,259,158)
1303			BADDEBT		-	-	-	-
1304			SNP		151,041,919	39,476,127	364,995,118	95,394,668
1305			CN		-	-	-	-
1306			SG		-	-	-	-
1307			DGP		-	-	-	-
1308			SE		26,719,047	7,037,562	64,891	17,092
1309			SG		169,882,496	45,671,477	155,762,417	41,875,413
1310			GPS		130,399,159	35,762,577	46,678,274	12,801,734
1311			SO		(302,537,538)	(82,972,329)	2,645,975	725,671
1312			TAXDEPR		1,264,819,225	332,584,303	1,397,330,243	367,428,084
1313			SNPD		44,060	11,014	(0)	(0)
1314				B6	1,789,129,685	381,408,520	1,706,840,094	516,983,504
1315								
1316	TOTAL SCHEDULE - M DEDUCTIONS			B6	1,792,776,633	382,368,862	1,707,522,793	517,163,102
1317								
1318	**TOTAL SCHEDULE - M ADJUSTMENTS**			**B6**	**(698,288,003)**	**(33,328,779)**	**(150,870,207)**	**(82,623,793)**
1319								
1320								
1321								
1322	40911	State Income Taxes						
1323					(12,026,323)	(4,482,603)	28,516,222	5,088,036
1324			S		9,593,106	2,984,000	6,828,200	219,094
1325		PTC	SG		-	-	-	-
1326			IBT		-	-	-	-
1327	**Total State Tax Expense**				**(2,433,217)**	**(1,498,603)**	**35,344,422**	**5,307,130**
1328								
1329								

2020 PROTOCOL

	Year End				**JUNE 2023**		**DECEMBER 2025**	
	FERC				**UNADJUSTED RESULTS**		**NORMALIZED RESULTS**	
	ACCT	**DESCRIP**	**FACTOR**	**Ref**	**TOTAL**	**OREGON**	**TOTAL**	**OREGON**
1330	Calculation of Taxable Income:							
1331		Operating Revenues			5,864,088,087	1,543,907,367	6,228,325,799	1,844,948,033
1332		Operating Deductions:						
1333		O & M Expenses			3,826,988,315	1,150,277,368	3,655,696,887	1,130,053,083
1334		Depreciation Expense			993,452,379	271,108,388	1,182,577,845	317,077,683
1335		Amortization Expense			76,333,322	15,984,719	100,491,871	30,904,843
1336		Taxes Other Than Income			188,692,373	74,630,102	249,331,003	100,572,803
1337		Interest & Dividends (AFUDC-Equity)			(103,524,703)	(27,057,087)	(250,960,991)	(65,590,851)
1338		Misc Revenue & Expense			(396,311)	(50,000)	(351,090)	(30,006)
1339		Total Operating Deductions			4,981,545,376	1,484,893,490	4,936,785,525	1,512,987,554
1340		Other Deductions:						
1341		Interest Deductions			449,151,688	124,420,851	512,559,451	137,265,413
1342		Interest on PCRBS			-	-	-	-
1343		Schedule M Adjustments			(698,288,003)	(33,328,779)	(150,870,207)	(82,623,793)
1344								
1345		Income Before State Taxes			(264,896,980)	(98,735,753)	628,110,617	112,071,272
1346								
1347		State Income Taxes			(2,433,217)	(1,498,603)	35,344,422	5,307,130
1348								
1349	Total Taxable Income				(262,463,763)	(97,237,150)	592,766,195	106,764,142
1350								
1351	Tax Rate				21.0%	21.0%	21.0%	21.0%
1352								
1353	Federal Income Tax - Calculated				(55,117,390)	(20,419,802)	124,480,901	22,420,470
1354								
1355	Adjustments to Calculated Tax:							
1356	40910		SE		(2,701)	(711)	(15,000)	(3,951)
1357	40910	PTC	SG		(196,377,610)	(52,794,465)	(242,529,591)	(65,202,036)
1358	40910		SO		(38,776)	(10,634)	(33,410)	(9,163)
1359	40910	IRS Settle	S		-	-	-	-
1360	**Federal Income Tax Expense**				**(251,536,478)**	**(73,225,613)**	**(118,097,100)**	**(42,794,680)**
1361								
1362	**Total Operating Expenses**				**4,885,362,180**	**1,427,270,327**	**4,989,176,149**	**1,536,153,644**
1363	310	Land and Land Rights						
1364			SG		2,327,033	625,603	2,327,033	625,603
1365			SG		33,769,530	9,078,654	33,769,530	9,078,654
1366			SG		54,351,537	14,611,953	54,351,537	14,611,953
1367			S		-	-	-	-
1368			SG		1,266,851	340,582	1,266,851	340,582
1369				B8	91,714,952	24,656,792	91,714,952	24,656,792
1370								
1371	311	Structures and Improvements						
1372			SG		225,389,076	60,593,953	225,389,076	60,593,953
1373			SG		311,097,937	83,636,058	311,097,937	83,636,058
1374			SG		471,568,481	126,777,211	471,568,481	126,777,211
1375			SG		-	-	-	-
1376				B8	1,008,055,494	271,007,222	1,008,055,494	271,007,222
1377								
1378	312	Boiler Plant Equipment						
1379			SG		584,581,300	157,159,755	584,581,300	157,159,755
1380			SG		462,513,467	124,342,847	462,513,467	124,342,847
1381			SG		3,398,079,363	913,544,993	3,507,993,276	943,094,422
1382			SG		-	-	-	-
1383				B8	4,445,174,129	1,195,047,595	4,555,088,042	1,224,597,024
1384								
1385	314	Turbogenerator Units						
1386			SG		108,374,641	29,135,609	108,374,641	29,135,609
1387			SG		106,495,684	28,630,467	106,495,684	28,630,467
1388			SG		778,564,077	209,310,389	778,564,077	209,310,389
1389			SG		-	-	-	-
1390				B8	993,434,402	267,076,465	993,434,402	267,076,465
1391								
1392	315	Accessory Electric Equipment						
1393			SG		85,682,834	23,035,108	85,682,834	23,035,108
1394			SG		133,070,911	35,774,993	133,070,911	35,774,993
1395			SG		209,782,111	56,398,152	209,782,111	56,398,152
1396			SG		-	-	-	-
1397				B8	428,535,856	115,208,253	428,535,856	115,208,253
1398								
1399								
1400								
1401	316	Misc Power Plant Equipment						
1402			SG		2,348,343	631,332	2,348,343	631,332
1403			SG		4,812,938	1,293,918	4,812,938	1,293,918
1404			SG		26,807,198	7,206,889	26,807,198	7,206,889
1405			SG		-	-	-	-
1406				B8	33,968,479	9,132,139	33,968,479	9,132,139

2020 PROTOCOL Year End FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2023 UNADJUSTED RESULTS TOTAL	JUNE 2023 UNADJUSTED RESULTS OREGON	DECEMBER 2025 NORMALIZED RESULTS TOTAL	DECEMBER 2025 NORMALIZED RESULTS OREGON
317	Steam Plant ARO						
		S		-	-	-	-
			B8	-	-	-	-
SP	Unclassified Steam Plant - Account 300						
		SG		17,789,039	4,782,433	17,789,039	4,782,433
			B8	17,789,039	4,782,433	17,789,039	4,782,433
Total Steam Production Plant			**B8**	**7,018,672,351**	**1,886,910,899**	**7,128,586,264**	**1,916,460,328**
Summary of Steam Production Plant by Factor							
	S			-	-	-	-
	DGP			-	-	-	-
	DGU			-	-	-	-
	SG			7,018,672,351	1,886,910,899	7,128,586,264	1,916,460,328
	SSGCH			-	-	-	-
Total Steam Production Plant by Factor				7,018,672,351	1,886,910,899	7,128,586,264	1,916,460,328
320	Land and Land Rights						
		SG		-	-	-	-
		SG		-	-	-	-
			B8	-	-	-	-
321	Structures and Improvements						
		SG		-	-	-	-
		SG	B8	-	-	-	-
				-	-	-	-
322	Reactor Plant Equipment						
		SG		-	-	-	-
		SG		-	-	-	-
			B8	-	-	-	-
323	Turbogenerator Units						
		SG		-	-	-	-
		SG		-	-	-	-
			B8	-	-	-	-
324	Land and Land Rights						
		SG		-	-	-	-
		SG		-	-	-	-
			B8	-	-	-	-
325	Misc. Power Plant Equipment						
		SG		-	-	-	-
		SG		-	-	-	-
			B8	-	-	-	-
NP	Unclassified Nuclear Plant - Acct 300						
		SG		-	-	-	-
			B8	-	-	-	-
Total Nuclear Production Plant			**B8**	**-**	**-**	**-**	**-**
Summary of Nuclear Production Plant by Factor							
	DGP			-	-	-	-
	DGU			-	-	-	-
	SG			-	-	-	-
Total Nuclear Plant by Factor				-	-	-	-
330	Land and Land Rights						
		SG		9,836,805	2,644,542	9,836,805	2,644,542
		SG		5,264,970	1,415,443	5,264,970	1,415,443
		SG		22,035,950	5,924,179	22,035,950	5,924,179
		SG		1,333,374	358,466	1,333,374	358,466
			B8	38,471,099	10,342,631	38,471,099	10,342,631
331	Structures and Improvements						
		SG		15,172,569	4,079,017	15,172,569	4,079,017
		SG		4,752,295	1,277,614	4,752,295	1,277,614
		SG		245,366,398	65,964,688	245,366,398	65,964,688
		SG		17,369,258	4,669,579	17,369,258	4,669,579
			B8	282,660,520	75,990,898	282,660,520	75,990,898

Line	2020 PROTOCOL Year End FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2023 UNADJUSTED RESULTS TOTAL	OREGON	DECEMBER 2025 NORMALIZED RESULTS TOTAL	OREGON
1487								
1488	332	Reservoirs, Dams & Waterways						
1489			SG		126,238,846	33,938,250	126,238,846	33,938,250
1490			SG		18,671,362	5,019,638	18,671,362	5,019,638
1491			SG		281,996,011	75,812,251	382,550,491	102,845,475
1492			SG		87,475,205	23,516,971	117,873,002	31,689,163
1493			SG		-	-	(1,321,596)	(355,300)
1494				B8	514,381,425	138,287,110	644,012,105	173,137,226
1495								
1496	333	Water Wheel, Turbines, & Generators						
1497			SG		25,499,649	6,855,366	25,499,649	6,855,366
1498			SG		6,690,812	1,798,769	6,690,812	1,798,769
1499			SG		53,799,268	14,463,480	53,799,268	14,463,480
1500			SG		44,593,709	11,988,643	44,593,709	11,988,643
1501				B8	130,583,438	35,106,257	130,583,438	35,106,257
1502								
1503	334	Accessory Electric Equipment						
1504			SG		2,782,502	748,052	2,782,502	748,052
1505			SG		3,335,903	896,830	3,335,903	896,830
1506			SG		55,539,496	14,931,325	55,539,496	14,931,325
1507			SG		11,384,099	3,060,519	11,384,099	3,060,519
1508				B8	73,042,000	19,636,726	73,042,000	19,636,726
1509								
1510								
1511								
1512	335	Misc. Power Plant Equipment						
1513			SG		973,732	261,780	973,732	261,780
1514			SG		150,826	40,548	150,826	40,548
1515			SG		1,497,327	402,544	1,497,327	402,544
1516			SG		61,353	16,494	61,353	16,494
1517				B8	2,683,238	721,366	2,683,238	721,366
1518								
1519	336	Roads, Railroads & Bridges						
1520			SG		3,221,794	866,152	3,221,794	866,152
1521			SG		734,401	197,437	734,401	197,437
1522			SG		18,101,409	4,866,411	18,101,409	4,866,411
1523			SG		3,552,346	955,018	3,552,346	955,018
1524				B8	25,609,949	6,885,019	25,609,949	6,885,019
1525								
1526	337	Hydro Plant ARO						
1527			S		-	-	-	-
1528				B8	-	-	-	-
1529								
1530	HP	Unclassified Hydro Plant - Acct 300						
1531			S		-	-	-	-
1532			SG		-	-	-	-
1533			SG		-	-	-	-
1534			SG		-	-	-	-
1535				B8	-	-	-	-
1536								
1537	**Total Hydraulic Production Plant**			**B8**	**1,067,431,670**	**286,970,007**	**1,197,062,350**	**321,820,122**
1538								
1539	Summary of Hydraulic Plant by Factor							
1540		S			-	-	-	-
1541		SG			1,067,431,670	286,970,007	1,197,062,350	321,820,122
1542		DGP			-	-	-	-
1543		DGU			-	-	-	-
1544	Total Hydraulic Plant by Factor				1,067,431,670	286,970,007	1,197,062,350	321,820,122
1545								
1546	340	Land and Land Rights						
1547			S		74,986	74,986	74,986	74,986
1548			SG		39,022,504	10,490,871	39,022,504	10,490,871
1549			SG		13,533,305	3,638,315	13,533,305	3,638,315
1550			SG		235,129	63,213	235,129	63,213
1551				B8	52,865,925	14,267,385	52,865,925	14,267,385
1552								
1553	341	Structures and Improvements						
1554			S		73,237	3,756	73,237	3,756
1555			SG		171,265,274	46,043,225	167,732,528	45,093,476
1556			SG		-	-	-	-
1557			SG		100,605,967	27,047,066	100,605,967	27,047,066
1558			SG		4,273,000	1,148,760	4,273,000	1,148,760
1559				B8	276,217,478	74,242,807	272,684,733	73,293,058
1560								
1561	342	Fuel Holders, Producers & Accessories						
1562			SG		13,650,230	3,669,749	13,650,230	3,669,749
1563			SG		-	-	-	-
1564			SG		2,789,123	749,832	2,789,123	749,832
1565				B8	16,439,353	4,419,581	16,439,353	4,419,581

2020 PROTOCOL Year End FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2023 UNADJUSTED RESULTS TOTAL	OREGON	DECEMBER 2025 NORMALIZED RESULTS TOTAL	OREGON
343	Prime Movers						
		S		-	-	370,052	370,052
		SG		-	-	-	-
		SG		2,881,792,687	774,745,672	3,513,661,830	944,618,365
		SG		1,084,643,002	291,597,128	927,563,118	249,367,526
		SG		61,119,971	16,431,589	61,119,971	16,431,589
			B8	4,027,555,661	1,082,774,390	4,502,714,972	1,210,787,532
344	Generators						
		S		284,866	-	284,866	-
		SG		165,210,609	44,415,479	165,210,609	44,415,479
		SG		411,075,318	110,514,134	403,144,993	108,382,133
		SG		17,799,825	4,785,333	17,799,825	4,785,333
			B8	594,370,618	159,714,947	586,440,293	157,582,946
345	Accessory Electric Plant						
		S		597,074	516,566	597,074	516,566
		SG		211,863,593	56,957,741	199,420,171	53,612,432
		SG		247,641,485	66,576,326	247,641,485	66,576,326
		SG		-	-	-	-
		SG		2,901,493	780,042	2,901,493	780,042
			B8	463,003,645	124,830,675	450,560,223	121,485,366
346	Misc. Power Plant Equipment						
		SG		12,977,877	3,488,993	12,318,380	3,311,693
		SG		11,863,573	3,189,422	11,863,573	3,189,422
		SG		-	-	-	-
			B8	24,841,450	6,678,415	24,181,953	6,501,114
347	Other Production ARO						
		S		-	-	-	-
			B8	-	-	-	-
OP	Unclassified Other Prod Plant-Acct 300						
		S		-	-	-	-
		SG		-	-	-	-
				-	-	-	-
Total Other Production Plant			**B8**	**5,455,294,130**	**1,466,928,199**	**5,905,887,451**	**1,588,336,982**
Summary of Other Production Plant by Factor							
	S			1,030,163	595,308	1,400,215	965,360
	DGU			-	-	-	-
	SG			5,454,263,967	1,466,332,892	5,904,487,236	1,587,371,623
	SSGCT			-	-	-	-
Total of Other Production Plant by Factor				5,455,294,130	1,466,928,199	5,905,887,451	1,588,336,982
Experimental Plant							
103	Experimental Plant						
		SG		-	-	-	-
Total Experimental Production Plant			**B8**	**-**	**-**	**-**	**-**
Total Production Plant			**B8**	**13,541,398,150**	**3,640,809,105**	**14,231,536,065**	**3,826,617,433**
350	Land and Land Rights						
		SG		20,408,749	5,486,720	20,408,749	5,486,720
		SG		46,464,678	12,491,637	46,464,678	12,491,637
		SG		279,952,592	75,262,894	279,952,592	75,262,894
			B8	346,826,019	93,241,252	346,826,019	93,241,252
352	Structures and Improvements						
		S		-	-	-	-
		SG		6,904,523	1,856,223	6,904,523	1,856,223
		SG		17,394,775	4,676,439	17,394,775	4,676,439
		SG		362,085,438	97,343,618	361,819,486	97,272,119
			B8	386,384,736	103,876,279	386,118,784	103,804,780
353	Station Equipment						
		SG		102,223,543	27,481,938	102,223,543	27,481,938
		SG		145,969,092	39,242,560	145,969,092	39,242,560
		SG		2,479,223,938	666,518,457	2,476,645,370	665,825,231
			B8	2,727,416,573	733,242,955	2,724,838,005	732,549,729
354	Towers and Fixtures						
		SG		128,106,134	34,440,254	128,106,134	34,440,254
		SG		131,173,487	35,264,886	131,173,487	35,264,886
		SG		1,266,725,416	340,548,450	1,266,725,416	340,548,450
			B8	1,526,005,036	410,253,591	1,526,005,036	410,253,591

2020 PROTOCOL Year End FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2023 UNADJUSTED RESULTS TOTAL	 OREGON	DECEMBER 2025 NORMALIZED RESULTS TOTAL	 OREGON
355	Poles and Fixtures						
		SG		58,479,814	15,721,805	58,479,814	15,721,805
		SG		112,737,819	30,308,612	112,737,819	30,308,612
		SG		1,107,620,922	297,774,548	4,277,795,479	1,150,049,256
			B8	1,278,838,555	343,804,966	4,449,013,112	1,196,079,673
356	Clearing and Grading						
		SG		156,662,797	42,117,472	156,662,797	42,117,472
		SG		156,151,321	41,979,966	156,151,321	41,979,966
		SG		1,363,305,469	366,513,184	1,363,293,697	366,510,019
			B8	1,676,119,586	450,610,622	1,676,107,815	450,607,457
357	Underground Conduit						
		SG		6,371	1,713	6,371	1,713
		SG		91,651	24,639	91,651	24,639
		SG		3,774,966	1,014,868	3,774,966	1,014,868
			B8	3,872,987	1,041,220	3,872,987	1,041,220
358	Underground Conductors						
		SG		-	-	-	-
		SG		1,087,552	292,379	1,087,552	292,379
		SG		7,993,065	2,148,868	7,993,065	2,148,868
			B8	9,080,617	2,441,247	9,080,617	2,441,247
359	Roads and Trails						
		SG		1,863,032	500,860	1,863,032	500,860
		SG		435,969	117,206	435,969	117,206
		SG		9,842,468	2,646,065	9,842,468	2,646,065
			B8	12,141,468	3,264,131	12,141,468	3,264,131
TP	Unclassified Trans Plant - Acct 300						
		SG		124,433,526	33,452,905	124,433,526	33,452,905
			B8	124,433,526	33,452,905	124,433,526	33,452,905
TS0	Unclassified Trans Sub Plant - Acct 300						
		SG		-	-	-	-
			B8	-	-	-	-
Total Transmission Plant			**B8**	**8,091,119,105**	**2,175,229,169**	**11,258,437,370**	**3,026,735,986**
Summary of Transmission Plant by Factor							
		DGP		-	-	-	-
		DGU		-	-	-	-
		SG		8,091,119,105	2,175,229,169	11,258,437,370	3,026,735,986
Total Transmission Plant by Factor				8,091,119,105	2,175,229,169	11,258,437,370	3,026,735,986
360	Land and Land Rights						
		S		77,395,334	15,474,248	85,343,751	16,501,049
			B8	77,395,334	15,474,248	85,343,751	16,501,049
361	Structures and Improvements						
		S		148,470,211	35,033,648	163,580,146	36,865,601
			B8	148,470,211	35,033,648	163,580,146	36,865,601
362	Station Equipment						
		S		1,245,973,796	306,033,063	1,372,829,387	321,458,778
			B8	1,245,973,796	306,033,063	1,372,829,387	321,458,778
363	Storage Battery Equipment						
		S		-	-	-	-
			B8	-	-	-	-
364	Poles, Towers & Fixtures						
		S		1,533,876,966	516,891,491	1,691,184,218	537,021,123
			B8	1,533,876,966	516,891,491	1,691,184,218	537,021,123
365	Overhead Conductors						
		S		960,820,986	325,012,527	1,047,879,016	326,142,454
			B8	960,820,986	325,012,527	1,047,879,016	326,142,454
366	Underground Conduit						
		S		487,803,339	120,810,576	537,892,224	127,274,252
			B8	487,803,339	120,810,576	537,892,224	127,274,252
367	Underground Conductors						
		S		1,111,073,914	235,065,979	1,225,180,008	249,806,557
			B8	1,111,073,914	235,065,979	1,225,180,008	249,806,557

	2020 PROTOCOL Year End FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2023 UNADJUSTED RESULTS TOTAL	 OREGON	DECEMBER 2025 NORMALIZED RESULTS TOTAL	 OREGON
1725								
1726	368	Line Transformers						
1727			S		1,622,032,246	532,450,677	1,788,599,594	553,956,506
1728				B8	1,622,032,246	532,450,677	1,788,599,594	553,956,506
1729								
1730	369	Services						
1731			S		1,034,745,809	359,517,354	1,141,007,446	373,239,647
1732				B8	1,034,745,809	359,517,354	1,141,007,446	373,239,647
1733								
1734	370	Meters						
1735			S		293,512,897	105,898,473	323,656,355	109,792,499
1736				B8	293,512,897	105,898,473	323,656,355	109,792,499
1737								
1738	371	Installations on Customers' Premises						
1739			S		8,872,474	2,685,798	9,783,668	2,803,509
1740				B8	8,872,474	2,685,798	9,783,668	2,803,509
1741								
1742	372	Leased Property						
1743			S		-	-	-	-
1744				B8	-	-	-	-
1745								
1746	373	Street Lights						
1747			S		63,188,232	25,130,359	69,677,429	25,968,508
1748				B8	63,188,232	25,130,359	69,677,429	25,968,508
1749								
1750	DP	Unclassified Dist Plant - Acct 300						
1751			S		91,005,899	24,538,568	91,005,899	24,538,568
1752				B8	91,005,899	24,538,568	91,005,899	24,538,568
1753								
1754	DS0	Unclassified Dist Sub Plant - Acct 300						
1755			S		-	-	-	-
1756				B8	-	-	-	-
1757								
1758								
1759	**Total Distribution Plant**			**B8**	**8,678,772,103**	**2,604,542,761**	**9,547,619,141**	**2,705,369,051**
1760								
1761	Summary of Distribution Plant by Factor							
1762		S			8,678,772,103	2,604,542,761	9,547,619,141	2,705,369,051
1763								
1764	Total Distribution Plant by Factor				8,678,772,103	2,604,542,761	9,547,619,141	2,705,369,051
1765	389	Land and Land Rights						
1766			S		16,330,314	6,116,556	16,330,314	6,116,556
1767			CN		1,128,506	346,514	1,128,506	346,514
1768			SG		332	89	332	89
1769			SG		1,228	330	1,228	330
1770			SO		7,611,617	2,087,521	7,611,617	2,087,521
1771				B8	25,071,997	8,551,011	25,071,997	8,551,011
1772								
1773	390	Structures and Improvements						
1774			S		150,891,908	44,350,073	150,891,908	44,350,073
1775			SG		335,238	90,126	335,238	90,126
1776			SG		1,356,387	364,653	1,356,387	364,653
1777			CN		8,218,829	2,523,635	8,218,829	2,523,635
1778			SG		10,331,894	2,777,643	10,331,894	2,777,643
1779			SE		940,953	247,839	940,953	247,839
1780			SO		112,996,016	30,989,684	112,996,016	30,989,684
1781				B8	285,071,225	81,343,652	285,071,225	81,343,652
1782								
1783	391	Office Furniture & Equipment						
1784			S		7,224,862	2,351,456	7,224,862	2,351,456
1785			SG		-	-	-	-
1786			SG		-	-	-	-
1787			CN		2,869,402	881,065	2,869,402	881,065
1788			SG		4,567,536	1,227,944	4,567,536	1,227,944
1789			SE		26,583	7,002	26,583	7,002
1790			SO		80,210,716	21,998,162	80,210,716	21,998,162
1791			SG		-	-	-	-
1792			SG		8,326	2,238	8,326	2,238
1793				B8	94,907,425	26,467,867	94,907,425	26,467,867

	2020 PROTOCOL Year End FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2023 UNADJUSTED RESULTS TOTAL	 OREGON	DECEMBER 2025 NORMALIZED RESULTS TOTAL	 OREGON
1794								
1795	392	Transportation Equipment						
1796			S		121,404,641	30,555,126	121,194,108	30,344,593
1797			SO		6,942,712	1,904,071	6,942,712	1,904,071
1798			SG		24,705,632	6,641,901	24,705,632	6,641,901
1799			CN		-	-	-	-
1800			SG		667,672	179,498	667,672	179,498
1801			SE		327,360	86,224	327,360	86,224
1802			SG		70,616	18,984	70,616	18,984
1803			SG		-	-	-	-
1804			SG		44,655	12,005	44,655	12,005
1805				B8	154,163,287	39,397,809	153,952,754	39,187,276
1806								
1807	393	Stores Equipment						
1808			S		10,705,594	3,157,311	10,546,743	2,998,461
1809			SG		-	-	-	-
1810			SG		-	-	-	-
1811			SO		242,940	66,627	242,940	66,627
1812			SG		6,911,513	1,858,102	6,911,513	1,858,102
1813			SG		53,971	14,510	53,971	14,510
1814				B8	17,914,017	5,096,550	17,755,167	4,937,700
1815								
1816	394	Tools, Shop & Garage Equipment						
1817			S		38,782,731	10,911,877	38,782,731	10,911,877
1818			SG		23,979	6,446	23,979	6,446
1819			SG		22,944,395	6,168,407	22,944,395	6,168,407
1820			SO		1,802,346	494,302	1,802,346	494,302
1821			SE		125,691	33,106	125,691	33,106
1822			SG		-	-	-	-
1823			SG		-	-	-	-
1824			SG		89,913	24,172	89,913	24,172
1825				B8	63,769,055	17,638,311	63,769,055	17,638,311
1826								
1827	395	Laboratory Equipment						
1828			S		28,155,412	10,593,738	27,882,938	10,321,264
1829			SG		-	-	-	-
1830			SG		-	-	-	-
1831			SO		5,070,769	1,390,682	5,070,769	1,390,682
1832			SE		1,326,848	349,480	1,326,848	349,480
1833			SG		7,511,378	2,019,371	7,422,750	1,995,544
1834			SG		-	-	-	-
1835			SG		14,022	3,770	14,022	3,770
1836				B8	42,078,428	14,357,041	41,717,326	14,060,740
1837								
1838	396	Power Operated Equipment						
1839			S		183,513,742	52,727,762	183,451,936	52,665,956
1840			SG		262,000	70,436	262,000	70,436
1841			SG		47,251,389	12,703,138	47,251,389	12,703,138
1842			SO		4,663,667	1,279,032	4,663,667	1,279,032
1843			SG		739,649	198,848	739,649	198,848
1844			SE		236,686	62,341	236,686	62,341
1845			SG		-	-	-	-
1846			SG		-	-	-	-
1847				B8	236,667,133	67,041,558	236,605,326	66,979,751
1848	397	Communication Equipment						
1849			S		205,678,174	64,283,709	305,897,824	124,669,936
1850			SG		-	-	-	-
1851			SG		139,259	37,439	139,259	37,439
1852			SO		95,836,464	26,283,597	161,444,092	44,276,794
1853			CN		3,458,622	1,061,988	1,533,847	470,976
1854			SG		206,696,110	55,568,507	195,826,707	52,646,359
1855			SE		361,776	95,289	161,042	42,417
1856			SG		-	-	-	-
1857			SG		16,633	4,472	16,633	4,472
1858				B8	512,187,037	147,335,000	665,019,403	222,148,393
1859								
1860	398	Misc. Equipment						
1861			S		3,742,268	1,374,243	3,742,268	1,374,243
1862			SG		-	-	-	-
1863			SG		-	-	-	-
1864			CN		70,861	21,758	70,861	21,758
1865			SO		1,574,970	431,943	1,574,970	431,943
1866			SE		3,966	1,045	3,966	1,045
1867			SG		3,113,773	837,112	3,113,773	837,112
1868			SG		-	-	-	-
1869				B8	8,505,838	2,666,100	8,505,838	2,666,100

	2020 PROTOCOL Year End FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2023 UNADJUSTED RESULTS TOTAL	OREGON	DECEMBER 2025 NORMALIZED RESULTS TOTAL	OREGON
1870								
1871	399	Coal Mine						
1872			SE		1,822,901	480,136	44,290,377	11,665,695
1873	MP		SE		-	-	-	-
1874				B8	1,822,901	480,136	44,290,377	11,665,695
1875								
1876	399L	WIDCO Capital Lease						
1877			SE		-	-	-	-
1878					-	-	-	-
1879								
1880		Remove Capital Leases			-	-	-	-
1881					-	-	-	-
1882								
1883	1011390	General Capital Leases						
1884			S		691,142	691,142	691,142	691,142
1885			SG		8,058,124	2,166,359	8,058,124	2,166,359
1886			SO		-	-	-	-
1887				B9	8,749,266	2,857,500	8,749,266	2,857,500
1888								
1889		Remove Capital Leases			(8,749,266)	(2,857,500)	(8,749,266)	(2,857,500)
1890					-	-	-	-
1891								
1892	1011346	General Gas Line Capital Leases						
1893			SG		-	-	-	-
1894				B9	-	-	-	-
1895								
1896		Remove Capital Leases			-	-	-	-
1897					-	-	-	-
1898								
1899	GP	Unclassified Gen Plant - Acct 300						
1900			S		-	-	-	-
1901			SO		65,411,605	17,939,437	65,411,605	17,939,437
1902			CN		-	-	-	-
1903			SG		-	-	-	-
1904			SG		-	-	-	-
1905			SG		-	-	-	-
1906				B8	65,411,605	17,939,437	65,411,605	17,939,437
1907								
1908	399G	Unclassified Gen Plant - Acct 300						
1909			S		-	-	-	-
1910			SO		-	-	-	-
1911			SG		-	-	-	-
1912			SG		-	-	-	-
1913			SG		-	-	-	-
1914				B8	-	-	-	-
1915								
1916	**Total General Plant**			**B8**	**1,507,569,947**	**428,314,471**	**1,702,077,498**	**513,585,933**
1917								
1918	Summary of General Plant by Factor							
1919		S			767,120,788	227,112,993	866,636,774	286,795,556
1920		DGP			-	-	-	-
1921		DGU			-	-	-	-
1922		SG			345,915,622	92,996,499	334,957,591	90,050,525
1923		SO			382,363,821	104,865,059	447,971,449	122,858,256
1924		SE			5,172,762	1,362,460	47,439,505	12,495,148
1925		CN			15,746,220	4,834,960	13,821,444	4,243,948
1926		DEU			-	-	-	-
1927		SSGCT			-	-	-	-
1928		SSGCH			-	-	-	-
1929		Less Capital Leases			(8,749,266)	(2,857,500)	(8,749,266)	(2,857,500)
1930	Total General Plant by Factor				1,507,569,947	428,314,471	1,702,077,498	513,585,933
1931	301	Organization						
1932			S		-	-	-	-
1933			SO		-	-	-	-
1934			SG		-	-	-	-
1935				B8	-	-	-	-
1936	302	Franchise & Consent						
1937			S		1,000,000	-	1,000,000	-
1938			SG		13,121,054	3,527,485	16,248,726	4,368,333
1939			SG		103,455,075	27,813,025	103,371,094	27,790,447
1940			SG		10,024,217	2,694,926	9,755,649	2,622,724
1941			SG		-	-	-	-
1942			SG		477,596	128,398	477,596	128,398
1943				B8	128,077,942	34,163,834	130,853,065	34,909,902

	2020 PROTOCOL Year End FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2023 UNADJUSTED RESULTS TOTAL	OREGON	DECEMBER 2025 NORMALIZED RESULTS TOTAL	OREGON
1944								
1945	303	Miscellaneous Intangible Plant						
1946			S		23,339,968	4,613,651	23,279,307	4,606,407
1947			SG		194,784,035	52,366,046	194,784,035	52,366,046
1948			SO		489,268,951	134,184,289	696,998,520	191,155,091
1949			SE		9,106	2,398	4,710	1,241
1950			CN		231,939,839	71,218,359	229,473,811	70,461,152
1951			SG		-	-	-	-
1952			SG		-	-	-	-
1953				B8	939,341,899	262,384,743	1,144,540,383	318,589,936
1954	303	Less Non-Regulated Plant						
1955			S		-	-	-	-
1956					939,341,899	262,384,743	1,144,540,383	318,589,936
1957	IP	Unclassified Intangible Plant - Acct 300						
1958			S		-	-	-	-
1959			SG		-	-	-	-
1960			SG		-	-	-	-
1961			SO		-	-	-	-
1962					-	-	-	-
1963								
1964	**Total Intangible Plant**			**B8**	**1,067,419,842**	**296,548,577**	**1,275,393,448**	**353,499,838**
1965								
1966	Summary of Intangible Plant by Factor							
1967		S			24,339,968	4,613,651	24,279,307	4,606,407
1968		DGP			-	-	-	-
1969		DGU			-	-	-	-
1970		SG			321,861,977	86,529,880	324,637,101	87,275,948
1971		SO			489,268,951	134,184,289	696,998,520	191,155,091
1972		CN			231,939,839	71,218,359	229,473,811	70,461,152
1973		SSGCT			-	-	-	-
1974		SSGCH			-	-	-	-
1975		SE			9,106	2,398	4,710	1,241
1976	Total Intangible Plant by Factor				1,067,419,842	296,548,577	1,275,393,448	353,499,838
1977	Summary of Unclassified Plant (Account 106)							
1978		DP			91,005,899	24,538,568	91,005,899	24,538,568
1979		DS0			-	-	-	-
1980		GP			65,411,605	17,939,437	65,411,605	17,939,437
1981		HP			-	-	-	-
1982		NP			-	-	-	-
1983		OP			-	-	-	-
1984		TP			124,433,526	33,452,905	124,433,526	33,452,905
1985		TS0			-	-	-	-
1986		IP			-	-	-	-
1987		MP			-	-	-	-
1988		SP			17,789,039	4,782,433	17,789,039	4,782,433
1989	Total Unclassified Plant by Factor				298,640,069	80,713,343	298,640,069	80,713,343
1990								
1991	**Total Electric Plant In Service**			**B8**	**32,886,279,146**	**9,145,444,083**	**38,015,063,522**	**10,425,808,241**
1992	Summary of Electric Plant by Factor							
1993		S			9,471,263,022	2,836,864,713	10,439,935,437	2,997,736,374
1994		SE			5,181,868	1,364,858	47,444,215	12,496,388
1995		DGU			-	-	-	-
1996		DGP			-	-	-	-
1997		SG			22,299,264,691	5,994,969,344	26,148,167,911	7,029,714,532
1998		SO			871,632,772	239,049,348	1,144,969,969	314,013,347
1999		CN			247,686,058	76,053,319	243,295,255	74,705,100
2000		DEU			-	-	-	-
2001		SSGCH			-	-	-	-
2002		SSGCT			-	-	-	-
2003		Less Capital Leases			(8,749,266)	(2,857,500)	(8,749,266)	(2,857,500)
2004					32,886,279,146	9,145,444,083	38,015,063,522	10,425,808,241
2005	105	Plant Held For Future Use						
2006			S		12,062,430	6,893,577	-	-
2007			SG		-	-	-	-
2008			SG		1,517,970	408,094	1,517,970	408,094
2009			SG		-	-	-	-
2010			SE		-	-	-	-
2011			SG		594,174	159,739	(1,517,970)	(408,094)
2012								
2013								
2014	**Total Plant Held For Future Use**			**B10**	**14,174,575**	**7,461,409**	**-**	**-**
2015								
2016	114	Electric Plant Acquisition Adjustments						
2017			S		11,763,784	-	11,763,784	-
2018			SG		144,704,699	38,902,639	144,704,699	38,902,639
2019			SG		-	-	-	-
2020	**Total Electric Plant Acquisition Adjustment**			**B15**	**156,468,483**	**38,902,639**	**156,468,483**	**38,902,639**

2020 PROTOCOL Year End FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2023 UNADJUSTED RESULTS TOTAL	OREGON	DECEMBER 2025 NORMALIZED RESULTS TOTAL	OREGON
115	Accum Provision for Asset Acquisition Adjustments						
		S		(2,500,812)	-	(2,500,812)	-
		SG		(142,013,501)	(38,179,133)	(142,088,852)	(38,199,390)
		SG		-	-	-	-
			B15	(144,514,313)	(38,179,133)	(144,589,665)	(38,199,390)
128	Pensions						
		SO		104,951,393	28,783,408	-	-
Total Pensions			**B15**	**104,951,393**	**28,783,408**	**-**	**-**
124	Weatherization						
		S		516,505	-	516,505	-
		SO		-	-	-	-
			B16	516,505	-	516,505	-
182W	Weatherization						
		S		224,013,752	-	224,013,752	-
		SG		-	-	-	-
		SGCT		-	-	-	-
		SO		-	-	-	-
			B16	224,013,752	-	224,013,752	-
186W	Weatherization						
		S		-	-	-	-
		CN		-	-	-	-
		CNP		-	-	-	-
		SG		-	-	-	-
		SO		-	-	-	-
			B16	-	-	-	-
Total Weatherization			**B16**	**224,530,257**	**-**	**224,530,257**	**-**
151	Fuel Stock						
		DEU		-	-	-	-
		SE		142,169,743	37,446,258	145,444,254	38,308,735
		SE		-	-	-	-
		SE		-	-	-	-
			B13	142,169,743	37,446,258	145,444,254	38,308,735
152	Fuel Stock - Undistributed						
		SE		-	-	-	-
				-	-	-	-
25316	UAMPS Working Capital Deposit						
		SE		(1,762,000)	(464,095)	240,231	63,275
			B13	(1,762,000)	(464,095)	240,231	63,275
25317	DG&T Working Capital Deposit						
		SE		(2,802,703)	(738,207)	(4,189,441)	(1,103,462)
			B13	(2,802,703)	(738,207)	(4,189,441)	(1,103,462)
25319	Provo Working Capital Deposit						
		SE		-	-	-	-
				-	-	-	-
Total Fuel Stock			**B13**	**137,605,040**	**36,243,955**	**141,495,044**	**37,268,548**
154	Materials and Supplies						
		S		250,693,096	92,111,560	250,693,096	92,111,560
		SG		(126,807)	(34,091)	(126,807)	(34,091)
		SE		-	-	-	-
		SO		(824,409)	(226,098)	(824,409)	(226,098)
		SG		134,063,446	36,041,827	134,063,446	36,041,827
		SG		33,938	9,124	33,938	9,124
		SNPD		(1,319,331)	(329,812)	(1,319,331)	(329,812)
		SG		-	-	-	-
		SG		-	-	-	-
		SG		-	-	-	-
		SG		-	-	-	-
		SG		8,640,607	2,322,954	8,640,607	2,322,954
		SG		-	-	-	-
			B13	391,160,539	129,895,465	391,160,539	129,895,465
158	WA GHG Allocation Inventory						
		S		16,242,900	-	16,242,900	-
			B13	16,242,900	-	16,242,900	-

	2020 PROTOCOL Year End FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2023 UNADJUSTED RESULTS TOTAL	OREGON	DECEMBER 2025 NORMALIZED RESULTS TOTAL	OREGON
2098								
2099	25318	Provo Working Capital Deposit						
2100			SG		(273,000)	(73,394)	(273,000)	(73,394)
2101								
2102				B13	(273,000)	(73,394)	(273,000)	(73,394)
2103								
2104	**Total Materials and Supplies**			**B13**	**407,130,439**	**129,822,071**	**407,130,439**	**129,822,071**
2105								
2106	165	Prepayments						
2107			S		51,220,696	4,549,813	51,220,696	4,549,813
2108			GPS		197,660	54,209	197,660	54,209
2109			SG		6,134,385	1,649,178	6,134,385	1,649,178
2110			SE		587,701	154,795	587,701	154,795
2111			SO		38,031,038	10,430,189	38,031,038	10,430,189
2112	**Total Prepayments**			**B15**	**96,171,480**	**16,838,184**	**96,171,480**	**16,838,184**
2113								
2114	182M	Misc Regulatory Assets						
2115			S		957,717,305	236,341	952,590,630	75,123
2116			SG		11,149,670	2,997,495	-	-
2117			SGCT		-	-	-	-
2118			SG-P		-	-	-	-
2119			SE		190,387,608	50,146,418	128,271,840	33,785,672
2120			SG		-	-	-	-
2121			SO		318,139,567	87,251,258	85,397,886	23,420,768
2122				B16	1,477,394,149	140,631,513	1,166,260,355	57,281,563
2123								
2124	186M	Misc Deferred Debits						
2125			S		3,427,151	-	3,427,151	-
2126			SG		-	-	-	-
2127			SG		-	-	-	-
2128			SG		155,505,931	41,806,459	165,821,117	44,579,610
2129			SO		-	-	-	-
2130			SE		306,510	80,732	306,510	80,732
2131			SG		-	-	-	-
2132			EXCTAX		-	-	-	-
2133	**Total Misc. Deferred Debits**			**B11**	**159,239,593**	**41,887,191**	**169,554,778**	**44,660,342**
2134								
2135	Working Capital							
2136	CWC	Cash Working Capital						
2137			S		85,383,086	34,740,058	83,534,345	36,025,180
2138			SO		-	-	-	-
2139			SE		-	-	-	-
2140				B14	85,383,086	34,740,058	83,534,345	36,025,180
2141								
2142	OWC	Other Work. Cap.						
2143	131	Cash	SNP		-	-	-	-
2144	135	Working Funds	SG		-	-	-	-
2145	141	Notes Receivable	SO		-	-	-	-
2146	143	Other A/R	SO		67,575,159	18,532,802	67,575,159	18,532,802
2147	232	A/P	S		(24,331)	-	(24,331)	-
2148	232	A/P	SO		(6,461,727)	(1,772,159)	(6,461,727)	(1,772,159)
2149	232	A/P	SE		(2,815,901)	(741,683)	(2,815,901)	(741,683)
2150	232	A/P	SG		(4,621,875)	(1,242,552)	(4,621,875)	(1,242,552)
2151	2533	Other Msc. Df. Crd.	S		-	-	-	-
2152	2533	Other Msc. Df. Crd.	SE		(10,815,889)	(2,848,810)	(11,135,301)	(2,932,940)
2153	230	Asset Retir. Oblig.	SG		-	-	-	-
2154	230	Asset Retir. Oblig.	S		(2,022,628)	-	(2,022,628)	-
2155	254	Decom. Reg Liability	SG		-	-	-	-
2156	254	Reclam. Reg Liability	SE		-	-	-	-
2157	2533	Cholla Reclamation	SE		-	-	-	-
2158				B14	40,812,809	11,927,598	40,493,397	11,843,468
2159								
2160	**Total Working Capital**			**B14**	**126,195,894**	**46,667,656**	**124,027,742**	**47,868,648**
2161	Miscellaneous Rate Base							
2162	18221	Unrec Plant & Reg Study Costs						
2163			S		-	-	-	-
2164								
2165					-	-	-	-
2166								
2167	18222	Nuclear Plant - Trojan						
2168			S		-	-	-	-
2169			TROJP		-	-	-	-
2170			TROJD		-	-	-	-
2171				B16	-	-	-	-

	2020 PROTOCOL Year End FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2023 UNADJUSTED RESULTS TOTAL	 OREGON	DECEMBER 2025 NORMALIZED RESULTS TOTAL	 OREGON
2172								
2173								
2174								
2175	1869	Misc Deferred Debits-Trojan						
2176			S		-	-	-	-
2177			SG		-	-	-	-
2178					-	-	-	-
2179								
2180	**Total Miscellaneous Rate Base**			**B15**	**-**	**-**	**-**	**-**
2181								
2182	**Total Rate Base Additions**				**2,759,346,990**	**449,058,893**	**2,341,048,913**	**334,442,604**
2183	235	Customer Service Deposits						
2184			S		-	-	-	-
2185			CN		-	-	-	-
2186	**Total Customer Service Deposits**			B15	-	-	-	-
2187								
2188	2281	Prop Ins	S		(967,647)	31,639,210	(967,647)	31,639,210
2189	2282	Inj & Dam	SO		(526,198,873)	(144,312,492)	-	-
2190	2283	Pen & Ben	SO		(1,252,613)	(343,535)	(1,252,613)	(343,535)
2191	2282	Prov for Injuries & Da	S		(4,316,923)	(4,316,923)	5,479,612	5,479,612
2192	2281	Prop Ins	SO		(10,000,000)	(2,742,547)	-	-
2193	25335	Reg Liabilities	SE		(115,119,099)	(30,321,356)	(115,119,099)	(30,321,356)
2194				B15	(657,855,155)	(150,397,643)	(111,859,747)	6,453,930
2195								
2196	22841	Accum Misc. Operating Provisions						
2197			S		-	-	-	-
2198			SG		(234,889)	(63,148)	(234,889)	(63,148)
2199				B15	(234,889)	(63,148)	(234,889)	(63,148)
2200								
2201	254105	ARO	S		-	-	-	-
2202	230	ARO	TROJD		(6,946,250)	(1,860,674)	(6,946,250)	(1,860,674)
2203	254	Reg Liabilities	SO		(33,831,393)	(9,278,417)	(33,831,393)	(9,278,417)
2204	254		S		(1,517,888,367)	(359,427,149)	(1,497,074,689)	(338,613,472)
2205				B15	(1,558,666,010)	(370,566,240)	(1,537,852,333)	(349,752,563)
2206								
2207	252	Customer Advances for Construction						
2208			S		(31,225,486)	(30,377,839)	(39,124,188)	(5,177,396)
2209			SE		-	-	-	-
2210			SG		(162,194,505)	(43,604,625)	(154,295,803)	(41,481,126)
2211			SO		-	-	-	-
2212			CN		-	-	-	-
2213	**Total Customer Advances for Construction**			**B20**	**(193,419,991)**	**(73,982,464)**	**(193,419,991)**	**(46,658,522)**
2214								
2215	25398	SO2 Emissions						
2216			SE		-	-	-	-
2217					-	-	-	-
2218								
2219	25399	Other Deferred Credits						
2220			S		(75,556,188)	(331,064)	(75,556,188)	(331,064)
2221			SO		(12,178,111)	(3,339,904)	(12,178,111)	(3,339,904)
2222			SG		(304,720,623)	(81,921,571)	(304,720,623)	(81,921,571)
2223			SE		(15,783,288)	(4,157,179)	(15,783,288)	(4,157,179)
2224				B15	(408,238,211)	(89,749,718)	(408,238,211)	(89,749,718)
2225								
2226	190	Accumulated Deferred Income Taxes						
2227			S		378,209,035	89,316,945	376,238,926	80,908,155
2228			CN		-	-	-	-
2229			SO		203,180,962	55,723,325	46,622,158	12,786,344
2230			DGP		-	-	-	-
2231			IBT		-	-	-	-
2232			SG		-	-	-	-
2233			SG		-	-	-	-
2234			BADDEBT		6,204,844	2,416,080	6,374,315	2,482,069
2235			TROJD		1,177,177	315,327	1,151,728	308,510
2236			SG		1,904,417	511,987	1,608,485	432,428
2237			SE		32,356,562	8,522,433	4,247,960	1,118,875
2238			SNP		-	-	-	-
2239			SNPD		549,138	137,276	2,308,230	577,021
2240			SG		-	-	-	-
2241				B19	623,582,135	156,943,372	438,551,802	98,613,403
2242								
2243	281	Accumulated Deferred Income Taxes						
2244			S		-	-	-	-
2245			SG		(128,320,334)	(34,497,840)	(0)	(0)
2246			SG		-	-	-	-
2247				B19	(128,320,334)	(34,497,840)	(0)	(0)

2020 PROTOCOL Year End FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2023 UNADJUSTED RESULTS TOTAL	OREGON	DECEMBER 2025 NORMALIZED RESULTS TOTAL	OREGON
282	Accumulated Deferred Income Taxes						
		S		54,870,428	13,614,613	(481,889,357)	(67,722,863)
		DITBAL		(3,020,857,941)	(753,720,323)	(383,920)	(95,790)
		SNP		(249,251)	(65,144)	(249,251)	(65,144)
		SO		1,450	398	(167,418,741)	(45,915,370)
		GPS		-	-	-	-
		CIAC		-	-	-	-
		SNPD		-	-	-	-
		SCHMDEXP		-	-	-	-
		TAXDEPR		-	-	-	-
		SG		-	-	-	-
		IBT		-	-	-	-
		SG		-	-	-	-
		CN		-	-	(21,827)	(6,702)
		SE		(1,612,025)	(424,593)	(1,242,990)	(327,393)
		SG		-	-	(2,482,770,307)	(667,471,869)
			B19	(2,967,847,339)	(740,595,049)	(3,133,976,393)	(781,605,130)
283	Accumulated Deferred Income Taxes						
		S		(281,809,078)	(8,730,572)	(291,231,674)	(8,897,652)
		SG		(3,309,478)	(889,725)	(1,536,694)	(413,127)
		SE		(35,177,917)	(9,265,553)	(613,153)	(161,499)
		SO		(125,140,421)	(34,320,343)	(30,805,535)	(8,448,561)
		GPS		(9,185,124)	(2,519,063)	(9,178,803)	(2,517,329)
		SNP		(538,350)	(140,703)	(530,040)	(138,531)
		TROJD		-	-	-	-
		SG		-	-	-	-
		SG		-	-	-	-
		SG		-	-	-	-
			B19	(455,160,369)	(55,865,960)	(333,895,898)	(20,576,699)
Total Accum Deferred Income Tax			**B19**	**(2,927,745,908)**	**(674,015,477)**	**(3,029,320,490)**	**(703,568,427)**
255	Accumulated Investment Tax Credit						
		S		(2,091,094)	-	(1,922,284)	-
		ITC84		-	-	-	-
		ITC85		-	-	-	-
		ITC86		-	-	-	-
		ITC88		-	-	-	-
		ITC89		-	-	-	-
		ITC90		-	-	-	-
		SG		(169,745)	(45,635)	(152,202)	(40,918)
Total Accumulated ITC			**B19**	**(2,260,839)**	**(45,635)**	**(2,074,486)**	**(40,918)**
Total Rate Base Deductions				**(5,748,421,002)**	**(1,358,820,325)**	**(5,283,000,146)**	**(1,183,379,365)**
108SP	Steam Prod Plant Accumulated Depr						
		S		(65,845,207)	-	(65,845,207)	-
		SG		(824,873,009)	(221,760,155)	(824,873,009)	(221,760,155)
		SG		(769,219,505)	(206,798,180)	(769,219,505)	(206,798,180)
		SG		(2,339,730,354)	(629,016,783)	(3,997,300,692)	(1,074,640,597)
		SG		-	-	-	-
		SG		-	-	-	-
			B17	(3,999,668,075)	(1,057,575,119)	(5,657,238,413)	(1,503,198,932)
108NP	Nuclear Prod Plant Accumulated Depr						
		SG		-	-	-	-
		SG		-	-	-	-
		SG		-	-	-	-
			B17	-	-	-	-
108HP	Hydraulic Prod Plant Accum Depr						
		S		-	-	-	-
		SG		(145,923,755)	(39,230,371)	(145,923,755)	(39,230,371)
		SG		(32,553,755)	(8,751,803)	(32,553,755)	(8,751,803)
		SG		(199,044,187)	(53,511,352)	(222,822,330)	(59,903,905)
		SG		(76,852,964)	(20,661,272)	(87,837,794)	(23,614,451)
		SG		-	-	(6,619,615)	(1,779,628)
			B17	(454,374,661)	(122,154,798)	(495,757,249)	(133,280,158)
108OP	Other Production Plant - Accum Depr						
		S		(44,745)	(310)	(173,198,503)	(173,154,068)
		SG		-	-	-	-
		SG		117,259,199	31,524,147	(91,457,351)	(24,587,538)
		SG		(568,854,645)	(152,931,776)	(641,654,082)	(172,503,291)
		SG		(50,136,554)	(13,478,790)	(50,136,554)	(13,478,790)
			B17	(501,776,746)	(134,886,729)	(956,446,490)	(383,723,687)

	2020 PROTOCOL Year End FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2023 UNADJUSTED RESULTS TOTAL	 OREGON	DECEMBER 2025 NORMALIZED RESULTS TOTAL	 OREGON
2329	108EP	Experimental Plant - Accum Depr						
2330			SG		-	-	-	-
2331			SG		-	-	-	-
2332					-	-	-	-
2333								
2334	**Total Production Plant Accum Depreciation**			**B17**	**(4,955,819,482)**	**(1,314,616,645)**	**(7,109,442,153)**	**(2,020,202,776)**
2335								
2336	Summary of Prod Plant Depreciation by Factor							
2337		S			(65,889,953)	(310)	(239,043,711)	(173,154,068)
2338		DGP			-	-	-	-
2339		DGU			-	-	-	-
2340		SG			(4,889,929,529)	(1,314,616,335)	(6,870,398,442)	(1,847,048,708)
2341		SSGCH			-	-	-	-
2342		SSGCT			-	-	-	-
2343	Total of Prod Plant Depreciation by Factor				(4,955,819,482)	(1,314,616,645)	(7,109,442,153)	(2,020,202,776)
2344								
2345								
2346	108TP	Transmission Plant Accumulated Depr						
2347			SG		(349,536,968)	(93,970,067)	(349,536,968)	(93,970,067)
2348			SG		(420,976,303)	(113,175,930)	(420,976,303)	(113,175,930)
2349			SG		(1,424,968,812)	(383,090,854)	(1,654,652,610)	(444,839,407)
2350	**Total Trans Plant Accum Depreciation**			**B17**	**(2,195,482,082)**	**(590,236,851)**	**(2,425,165,880)**	**(651,985,404)**
2351	108360	Land and Land Rights						
2352			S		(10,428,264)	(2,501,052)	(12,267,420)	(2,858,488)
2353				B17	(10,428,264)	(2,501,052)	(12,267,420)	(2,858,488)
2354								
2355	108361	Structures and Improvements						
2356			S		(36,908,591)	(9,863,390)	(40,436,632)	(10,548,995)
2357				B17	(36,908,591)	(9,863,390)	(40,436,632)	(10,548,995)
2358								
2359	108362	Station Equipment						
2360			S		(379,219,430)	(106,831,385)	(408,819,501)	(112,577,498)
2361				B17	(379,219,430)	(106,831,385)	(408,819,501)	(112,577,498)
2362								
2363	108363	Storage Battery Equipment						
2364			S		-	-	-	-
2365				B17	-	-	-	-
2366								
2367	108364	Poles, Towers & Fixtures						
2368			S		(718,134,437)	(269,538,865)	(754,546,320)	(276,584,933)
2369				B17	(718,134,437)	(269,538,865)	(754,546,320)	(276,584,933)
2370								
2371	108365	Overhead Conductors						
2372			S		(364,755,336)	(143,460,816)	(387,395,342)	(147,706,066)
2373				B17	(364,755,336)	(143,460,816)	(387,395,342)	(147,706,066)
2374								
2375	108366	Underground Conduit						
2376			S		(191,409,398)	(51,732,079)	(203,001,054)	(53,984,823)
2377				B17	(191,409,398)	(51,732,079)	(203,001,054)	(53,984,823)
2378								
2379	108367	Underground Conductors						
2380			S		(406,334,486)	(102,482,947)	(432,737,093)	(107,614,232)
2381				B17	(406,334,486)	(102,482,947)	(432,737,093)	(107,614,232)
2382								
2383	108368	Line Transformers						
2384			S		(636,665,915)	(262,971,898)	(675,209,628)	(270,462,078)
2385				B17	(636,665,915)	(262,971,898)	(675,209,628)	(270,462,078)
2386								
2387	108369	Services						
2388			S		(395,631,698)	(156,860,755)	(420,220,316)	(161,639,339)
2389				B17	(395,631,698)	(156,860,755)	(420,220,316)	(161,639,339)
2390								
2391	108370	Meters						
2392			S		(112,190,330)	(32,684,776)	(119,165,119)	(34,040,310)
2393				B17	(112,190,330)	(32,684,776)	(119,165,119)	(34,040,310)
2394								
2395								
2396								
2397	108371	Installations on Customers' Premises						
2398			S		(7,248,581)	(2,123,577)	(7,459,419)	(2,164,552)
2399				B17	(7,248,581)	(2,123,577)	(7,459,419)	(2,164,552)
2400								
2401	108372	Leased Property						
2402			S		-	-	-	-
2403				B17	-	-	-	-
2404								
2405	108373	Street Lights						
2406			S		(33,584,203)	(12,324,304)	(35,085,741)	(12,616,113)
2407				B17	(33,584,203)	(12,324,304)	(35,085,741)	(12,616,113)

2020 PROTOCOL Year End FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2023 UNADJUSTED RESULTS TOTAL	JUNE 2023 UNADJUSTED RESULTS OREGON	DECEMBER 2025 NORMALIZED RESULTS TOTAL	DECEMBER 2025 NORMALIZED RESULTS OREGON
108D00	Unclassified Dist Plant - Acct 300						
		S		-	-	-	-
			B17	-	-	-	-
108DS	Unclassified Dist Sub Plant - Acct 300						
		S		-	-	-	-
			B17	-	-	-	-
108DP	Unclassified Dist Sub Plant - Acct 300						
		S		2,140,729	685,999	2,140,729	685,999
			B17	2,140,729	685,999	2,140,729	685,999
Total Distribution Plant Accum Depreciation			**B17**	**(3,290,369,938)**	**(1,152,689,844)**	**(3,494,202,854)**	**(1,192,111,426)**
Summary of Distribution Plant Depr by Factor							
	S			(3,290,369,938)	(1,152,689,844)	(3,494,202,854)	(1,192,111,426)
Total Distribution Depreciation by Factor				(3,290,369,938)	(1,152,689,844)	(3,494,202,854)	(1,192,111,426)
108GP	General Plant Accumulated Depr						
		S		(303,587,815)	(91,214,708)	(330,848,307)	(96,741,359)
		SG		(473,066)	(127,180)	(473,066)	(127,180)
		SG		(2,092,186)	(562,467)	(2,092,186)	(562,467)
		SG		(142,888,014)	(38,414,238)	(155,924,142)	(41,918,891)
		CN		(6,304,713)	(1,935,895)	(5,485,751)	(1,684,429)
		SO		(121,429,156)	(33,302,512)	(135,829,842)	(37,251,967)
		SE		(1,798,513)	(473,712)	(1,912,546)	(503,748)
		SG		(149,363)	(40,155)	(149,363)	(40,155)
		SG		-	-	-	-
			B17	(578,722,825)	(166,070,867)	(632,715,203)	(178,830,195)
108MP	Mining Plant Accumulated Depr.						
		S		-	-	-	-
		SE		-	-	-	-
			B17	-	-	-	-
108MP	Less Centralia Situs Depreciation						
		S		-	-	-	-
			B17	-	-	-	-
1081390	Accum Depr - Capital Lease						
		SO	B17	-	-	-	-
				-	-	-	-
	Remove Capital Leases			-	-	-	-
			B17	-	-	-	-
1081399	Accum Depr - Capital Lease						
		S		-	-	-	-
		SE	B17	-	-	-	-
				-	-	-	-
	Remove Capital Leases			-	-	-	-
			B17	-	-	-	-
Total General Plant Accum Depreciation			**B17**	**(578,722,825)**	**(166,070,867)**	**(632,715,203)**	**(178,830,195)**
Summary of General Depreciation by Factor							
	S			(303,587,815)	(91,214,708)	(330,848,307)	(96,741,359)
	DGP			-	-	-	-
	DGU			-	-	-	-
	SE			(1,798,513)	(473,712)	(1,912,546)	(503,748)
	SO			(121,429,156)	(33,302,512)	(135,829,842)	(37,251,967)
	CN			(6,304,713)	(1,935,895)	(5,485,751)	(1,684,429)
	SG			(145,602,629)	(39,144,039)	(158,638,757)	(42,648,693)
	DEU			-	-	-	-
	SSGCT			-	-	-	-
	SSGCH			-	-	-	-
	Remove Capital Leases			-	-	-	-
Total General Depreciation by Factor				(578,722,825)	(166,070,867)	(632,715,203)	(178,830,195)
Total Accum Depreciation - Plant In Service			**B17**	**(11,020,394,328)**	**(3,223,614,207)**	**(13,661,526,090)**	**(4,043,129,802)**

	2020 PROTOCOL Year End FERC ACCT	DESCRIP	FACTOR	Ref	JUNE 2023 UNADJUSTED RESULTS TOTAL	OREGON	DECEMBER 2025 NORMALIZED RESULTS TOTAL	OREGON
2485	111OP	Accum Prov for Amort-Other						
2486			S		(92,148)	(92,148)	(198,109)	(198,109)
2487			SG		-	-	-	-
2488				B18	(92,148)	(92,148)	(198,109)	(198,109)
2489								
2490								
2491	111GP	Accum Prov for Amort-General						
2492			S		(12,628,554)	(5,064,283)	(13,259,862)	(5,273,651)
2493			CN		-	-	-	-
2494			SG		-	-	-	-
2495			SO		(1,442,803)	(395,695)	(1,504,848)	(412,712)
2496			SE		-	-	-	-
2497				B18	(14,071,356)	(5,459,979)	(14,764,710)	(5,686,363)
2498								
2499								
2500	111HP	Accum Prov for Amort-Hydro						
2501			SG		-	-	-	-
2502			SG		-	-	-	-
2503			SG		(3,764,748)	(1,012,121)	(4,235,565)	(1,138,696)
2504			SG		-	-	-	-
2505				B18	(3,764,748)	(1,012,121)	(4,235,565)	(1,138,696)
2506								
2507								
2508	111IP	Accum Prov for Amort-Intangible Plant						
2509			S		(1,666,939)	(149,822)	(1,871,328)	(159,409)
2510			SG		-	-	-	-
2511			SG		(421,999)	(113,451)	(421,999)	(113,451)
2512			SE		(5,540)	(1,459)	(2,923)	(770)
2513			SG		(108,800,207)	(29,250,019)	(116,718,993)	(31,378,917)
2514			SG		(45,827,311)	(12,320,286)	(49,765,034)	(13,378,910)
2515			SG		(6,403,898)	(1,721,634)	(6,610,880)	(1,777,279)
2516			CN		(185,912,323)	(57,085,366)	(206,894,836)	(63,528,158)
2517			SG		-	-	-	-
2518			SG		-	-	-	-
2519			SO		(364,651,322)	(100,007,324)	(421,136,121)	(115,498,543)
2520				B18	(713,689,539)	(200,649,360)	(803,422,114)	(225,835,437)
2521	111IP	Less Non-Regulated Plant						
2522			OTH		-	-	-	-
2523					(713,689,539)	(200,649,360)	(803,422,114)	(225,835,437)
2524								
2525	111390	Accum Amtr - Capital Lease						
2526			S		-	-	-	-
2527			SG		-	-	-	-
2528			SO		-	-	-	-
2529				B9	-	-	-	-
2530								
2531		Remove Capital Lease Amtr			-	-	-	-
2532								
2533	**Total Accum Provision for Amortization**			**B18**	**(731,617,791)**	**(207,213,607)**	**(822,620,498)**	**(232,858,605)**
2534								
2535								
2536								
2537								
2538	Summary of Amortization by Factor							
2539		S			(14,387,640)	(5,306,253)	(15,329,299)	(5,631,169)
2540		DGP			-	-	-	-
2541		DGU			-	-	-	-
2542		SE			(5,540)	(1,459)	(2,923)	(770)
2543		SO			(366,094,125)	(100,403,019)	(422,640,969)	(115,911,254)
2544		CN			(185,912,323)	(57,085,366)	(206,894,836)	(63,528,158)
2545		SSGCT			-	-	-	-
2546		SSGCH			-	-	-	-
2547		SG			(165,218,164)	(44,417,511)	(177,752,471)	(47,787,254)
2548		Less Capital Lease			-	-	-	-
2549	Total Provision For Amortization by Factor				(731,617,791)	(207,213,607)	(822,620,498)	(232,858,605)

Tab 1 - Retcl sc

Oregon General Rate Case – December 2025
Revenue Adjustment Index

The Company used actual revenue for the 12 months ended June 30, 2023 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 2025 test period.

3.1 Pro Forma Revenues
3.2 Confidential REC Revenue
3.3 Wheeling Revenue
3.4 Fly Ash Revenue

PacifiCorp
Oregon General Rate Case - December 2025
Tab 3 Adjustment Summary

		Total Adjustments	3.1 Pro Forma Revenues	3.2 REC Revenues_CONF	3.3 Wheeling Revenue	3.4 Fly Ash Revenue
1	Operating ReWenues:					
2	General Business ReWenues	280,144,493	280,144,493	-	-	-
3	Interdepartmental	-	-	-	-	-
4	Special Sales	-	-	-	-	-
5	Other Operating ReWenues	1,710,577	-	(1,404,981)	4,508,033	(1,392,474)
6	Total Operating ReWenues	281,855,070	280,144,493	(1,404,981)	4,508,033	(1,392,474)
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 SerWice & Info	-	-	-	-	-
17	Sales	-	-	-	-	-
18	AdministratiWe & General	-	-	-	-	-
19						
20	Total O&M Expenses	-	-	-	-	-
21						
22	Depreciation	-	-	-	-	-
23	Amortization	-	-	-	-	-
24	Taxes Other Than Income	-	-	-	-	-
25	Income Taxes - Federal	56,491,598	56,148,751	(281,597)	903,535	(279,091)
26	Income Taxes - State	12,793,783	12,716,138	(63,774)	204,626	(63,206)
27	Income Taxes - Def Net	-	-	-	-	-
28	InWestment Tax Credit Adj.	-	-	-	-	-
29	Misc ReWenue & Expense	-	-	-	-	-
30						
31	Total Operating Expenses:	69,285,381	68,864,889	(345,371)	1,108,161	(342,297)
32						
33	Operating ReW For Return:	212,569,689	211,279,604	(1,059,610)	3,399,872	(1,050,178)
34						
35	Rate Base:					
36	Electric Plant In SerWice	-	-	-	-	-
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	2,072,867	2,060,287	(10,333)	33,154	(10,241)
45	Weatherization Loans	-	-	-	-	-
46	Misc Rate Base	-	-	-	-	-
47						
48	Total Electric Plant:	2,072,867	2,060,287	(10,333)	33,154	(10,241)
49						
50	Rate Base Deductions:					
51	Accum ProW For Deprec	-	-	-	-	-
52	Accum ProW For Amort	-	-	-	-	-
53	Accum Def Income Tax	-	-	-	-	-
54	Unamortized ITC	-	-	-	-	-
55	Customer AdW For Const	-	-	-	-	-
56	Customer SerWice Deposits	-	-	-	-	-
57	Misc Rate Base Deductions	-	-	-	-	-
58						
59	Total Rate Base Deductions	-	-	-	-	-
60						
61	Total Rate Base:	2,072,867	2,060,287	(10,333)	33,154	(10,241)
62						
63	Return on Rate Base	4.421%	4.394%	-0.022%	0.071%	-0.022%
64						
65	Return on Equity	8.842%	8.789%	-0.044%	0.141%	-0.044%
66						
67	TAX CALCULATION:					
68	Operating ReWenue	281,855,070	280,144,493	(1,404,981)	4,508,033	(1,392,474)
69	Other Deductions		-	-	-	-
70	Interest (AFUDC)	-	-	-	-	-
71	Interest	53,677	53,351	(268)	859	(265)
72	Schedule "M" Additions	-	-	-	-	-
73	Schedule "M" Deductions	-	-	-	-	-
74	Income Before Tax	281,801,394	280,091,143	(1,404,714)	4,507,174	(1,392,209)
75						
76	State Income Taxes	12,793,783	12,716,138	(63,774)	204,626	(63,206)
77	Taxable Income	269,007,610	267,375,005	(1,340,940)	4,302,548	(1,329,003)
78						
79	Federal Income Taxes + Other	56,491,598	56,148,751	(281,597)	903,535	(279,091)
	APPROXIMATE PRICE CHANGE	(291,740,043)	(289,971,727)	1,452,405	(4,660,197)	1,439,476

PacifiCorp
Oregon General Rate Case - December 2025
Pro Forma Revenues

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Revenue:							
Residential	440	3	78,086,377	OR	Situs	78,086,377	3.1.1
Commercial	442	3	178,474,543	OR	Situs	178,474,543	3.1.1
Industrial [1]	442	3	24,965,661	OR	Situs	24,965,661	3.1.1
Public Street & Hwy	444	3	(1,382,088)	OR	Situs	(1,382,088)	3.1.1
			280,144,493			280,144,493	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 2025 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 2025
Pro Forma Revenues
Actual 12 Months Ended June 2023
Forecast 12 Months Ending December 2025

	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[2]	Actual Base Rate Revenues	Normalizing Adjustments[3]	Temperature Normalization	Total Type 1 Adjusted Revenue	Type 2 Annualized Price Change[4]	Total Type 2 Adjusted Revenue	Type 3 Pro Forma Price Change[5]	Total Oregon Forecast Revenue	**Total Adjustment**
Residential	$706,439,053	$19,866,890	$726,305,943	($12,676,449)	$713,629,494	$4,861,159	($31,554,309)	$686,936,345	$65,109,555	$752,045,900	$52,346,421	$804,392,320	**$78,086,377**
Commercial	$565,456,459	($33,252,749)	$532,203,710	($10,336,249)	$521,867,461	($8,899,121)	($7,194,472)	$505,773,867	$41,192,227	$546,966,094	$163,712,159	$710,678,253	**$178,474,543**
Industrial	$121,494,735	($9,394,844)	$112,099,891	($2,355,042)	$109,744,849	$1,691,245	$0	$111,436,095	$7,440,735	$118,876,830	$7,078,472	$125,955,301	**$13,855,410**
Irrigation	$24,011,059	($524,587)	$23,486,472	($300,870)	$23,185,602	$3,557,904	($2,597,580)	$24,145,927	$2,072,513	$26,218,439	$8,378,284	$34,596,723	**$11,110,251**
Public St & Hwy	$5,094,531	($167,018)	$4,927,512	($93,540)	$4,833,972	($892,372)	$0	$3,941,599	($265,672)	$3,675,928	($130,504)	$3,545,424	**($1,382,088)**
Total Oregon	$1,422,495,837	($23,472,308)	$1,399,023,529	($25,762,151)	$1,373,261,378	$318,815	($41,346,361)	$1,332,233,832	$115,549,358	$1,447,783,191	$231,384,831	$1,679,168,022	**$280,144,493**
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, Community Solar Revenue, Other Customer Retail Revenue, Revenue Adjustment I&D Reserve, DSM, Blue Sky, BPA, OCAT, and Climate Credit.

[2] Revenue Accounting Adjustments, Customer Bill Credits, Income Tax Deferral Adjustments, BPA (Sch98), Wildfire Mitigation and Vegetation Management Adjustment (Sch 94), Oregon Corporate Activities Tax Recovery Adjustment (104), Wildfire Mitigation Plan Cost Recovery Adjustment (Sch 190), Deferred Accounting Adjustment (Sch 192), Replaced Meter Deferred Amounts Adjustment (194), Federal Tax Act Adjustment (195), Deer Creek Mine Closure Deferred Amounts Adjustment (Sch 198), Renewable Resource Deferral Adjustment (Sch 203), Oregon Solar Incentive Program (Sch 204), Power Cost Adjustment Mechanism Adjustment (Sch 206) and Community Solar Adjustment (207).

[3] Removal of Irrigation Demand Charge Accrual (net zero for calendar year), Rate Mitigation Adjustment (299), & Out of Period adjustment

[4] Includes rate changes for: General Rate Case (GRC) and Transition Adjustment Mechanism (TAM) effective January 1, 2023 Includes adjustment bringing direct access consumers to cost of service.

[5] TAM and Renewable Adjustment Clause (RAC) rate change effective January 1, 2024; adjustment to forecast.

PacifiCorp
Oregon General Rate Case - December 2025
Adjustment to MWhs
Historical 12 Months Ended June 2023; Forecast 12 Months Ended December 2025

	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	6,213,736	(7,730)	(300,945)	5,905,061	135	5,905,196	31,163	5,936,359
Commercial	6,060,427	5,408	(123,965)	5,941,871	93,137	6,035,007	1,616,111	7,651,118
Industrial	1,487,208	(2,037)	0	1,485,171	43,484	1,528,655	(61,114)	1,467,541
Irrigation	215,170	6,222	(27,669)	193,723	25	193,748	60,298	254,046
Public St & Hwy	31,402	(157)	0	31,245	(0)	31,244	(958)	30,286
Total Oregon	14,007,943	1,706	(452,579)	13,557,071	136,781	13,693,852	1,645,500	15,339,352
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
Oregon General Rate Case - December 2025
Present TAM Revenues In Rates
Forecast 12 Months Ended December 31, 2025

Base Rate Schedule	MWH	TAM Collection (Schedule 201 Revenue)
4	5,787,620	$244,501,472
23	1,162,132	$46,269,926
28	2,064,712	$81,165,170
30	1,330,279	$51,285,435
41	234,910	$8,924,213
47	43,379	$1,442,108
48	4,677,111	$170,224,355
848	0	$0
15	8,157	$111,792
51	20,858	$353,820
53	8,821	$116,441
54	1,374	$18,132
Total	15,339,352	$604,412,863

Comparison to UE 420	MWH	Approved TAM
2024 Test Period	16,835,899	$660,094,810
Difference resulting from change in test period	(1,496,547)	($55,681,947)
Percentage Change	-8.9%	-8.4%

PacifiCorp
Oregon General Rate Case - December 2025
Revenue split between TAM and GRC Proforma Revenue

Total Revenue - 2025	TAM/ NPC	NON-TAM / NON NPC
$1,679,168,022	$604,412,863	$1,074,755,159
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 2025
Historical 12 Months Ended June 2023; Forecast 12 Months Ended December 2025
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	2,214	-117	2,097	1,857,326	5,564		5,564	1,862,890
4	532,643	-19,062	513,581	6,117,681,583	(7,399,978)	(296,196,346)	(303,596,324)	5,814,085,259
23	17,201	250	17,451	99,237,877	(45,676)	(4,748,288)	(4,793,964)	94,443,913
28	225	12	237	48,083,884	(289,915)		(289,915)	47,793,969
BPA Balancing Account	0			0			0	0
Solar Feed-In Revenue	0			0			0	0
Revenue Accounting Adjustment	0			0			0	0
Other Customer Retail Rev	0			0			0	0
Community 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			(53,125,000)			0	(53,125,000)
Paperless Credit	0			0			0	0
AGA	0			0			0	0
Total Residential	**552,283**	**(18,917)**	**533,366**	**6,213,735,670**	**(7,730,005)**	**(300,944,633)**	**(308,674,638)**	**5,905,061,032**
Commercial								
15	3,634	-14	3,620	6,132,494	(6,347)		(6,347)	6,126,147
23	66,426	1,170	67,596	1,111,938,565	(2,527,986)	(22,940,932)	(25,468,918)	1,086,469,647
28	9,775	259	10,034	1,975,972,605	(1,936,707)	(40,997,676)	(42,934,383)	1,933,038,222
30	716	6	722	1,088,443,583	2,190,265	(23,074,796)	(20,884,531)	1,067,559,052
47	5	0	5	45,110,849	(401,000)		(401,000)	44,709,849
48	95	3	98	1,750,752,139	8,078,200	(36,951,287)	(28,873,087)	1,721,879,052
54	98	0	98	1,438,112	11,767		11,767	1,449,879
BPA Balancing Account	0			0			0	0
Solar Feed-In Revenue	0			0			0	0
Revenue Accounting Adjustment	0			0			0	0
Community 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			80,639,000			0	80,639,000
Paperless Credit	0			0			0	0
AGA	0			0			0	0
Total Commercial	**80,750**	**1,423**	**82,173**	**6,060,427,347**	**5,408,192**	**(123,964,690)**	**(118,556,498)**	**5,941,870,849**
Industrial								
15	115	1	116	246,566	(688)		(688)	245,878
23	968	3	971	18,665,782	(49,043)	0	(49,043)	18,616,739
28	391	-4	387	79,960,014	(584,207)	0	(584,207)	79,375,807
30	123	2	125	179,927,795	1,573,660		1,573,660	181,501,455
47	1	0	1	960,000	0		0	960,000
48	80	-2	78	1,224,925,280	(2,977,100)		(2,977,100)	1,221,948,180
BPA Balancing Account	0			0			0	0
Solar Feed-In Revenue	0			0			0	0
Revenue Accounting Adjustment	0			0			0	0
Community 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			(17,477,000)			0	(17,477,000)
Paperless Credit	0			0			0	0
AGA	0			0			0	0
Total Industrial	**1,678**	**0**	**1,678**	**1,487,208,437**	**(2,037,378)**	**0**	**(2,037,378)**	**1,485,171,059**
Irrigation								
41	7,923	-39	7,884	191,106,068	5,194,990	(24,886,718)	(19,691,728)	171,414,340
23	1	0	1	2,065	0		0	2,065
48	2	0	2	19,327,200	1,027,200	(2,782,588)	(1,755,388)	17,571,812
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
Revenue Accounting Adjustment	0			0			0	0
Community 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			4,735,000			0	4,735,000
Paperless Credit	0			0			0	0
AGA	0			0			0	0
Total Irrigation	**7,926**	**(39)**	**7,887**	**215,170,333**	**6,222,190**	**(27,669,306)**	**(21,447,116)**	**193,723,217**
Lighting								
15	18	-18	0	24,367	(176)		(176)	24,191
23	14	0	14	604,221	(25)		(25)	604,196
51	1,194	16	1,210	23,702,071	(117,814)		(117,814)	23,584,257
53	296	0	296	8,113,921	(38,843)		(38,843)	8,075,078
Solar Feed-In Revenue	0			0			0	0
Revenue Accounting Adjustment	0			0			0	0
Community Solar Revenue	0			0			0	0
Other Customer Retail Rev	0			0			0	0
DSM	0			0			0	0
Income Tax Deferral Adjustments	0			0				0
Unbilled	0			(1,043,000)			0	(1,043,000)
Paperless Credit	0			0			0	0
AGA	0			0			0	0
Total Lighting	**1,521**	**(1)**	**1,520**	**31,401,580**	**(156,858)**	**0**	**(156,858)**	**31,244,722**
TOTAL COMPANY	**644,158**	**(17,534)**	**626,624**	**14,007,943,367**	**1,706,141**	**(452,578,630)**	**(450,872,489)**	**13,557,070,878**

PacifiCorp
Oregon General Rate Case - December 2025
Historical 12 Months Ended June 2023; Foreca
Revenue, kWh and Customer Adjustments

	KWH				REVENUES		
	Type 2		Type 3			Type 1	
	Blocking Adjustment kWh	Total Type 2 Adjusted kWh	Forecast Adjustment kWh	Total Type 3 Adjusted kWh	305 Booked Revenues	Remove Tariff Riders $	Actual Base Rate Revenues
Residential							
15	(263)	1,862,627	(98,599)	1,764,028	$283,410	($137)	$283,273
4	186,807	5,814,272,066	(26,652,007)	5,787,620,059	$654,209,459	$42,434,748	$696,644,207
23	(81,749)	94,362,164	(307,546)	94,054,618	$12,986,776	$693,539	$13,680,315
28	30,429	47,824,398	5,096,169	52,920,567	$3,903,311	$241,967	$4,145,278
BPA Balancing Account		0		0	($531,705)	$531,705	$0
Solar Feed-In Revenue		0		0	$1,902,062	($1,902,062)	$0
Revenue Accounting Adjustment		0		0	($1,056,099)	$1,056,099	$0
Other Customer Retail Rev		0		0	$592,139	($592,139)	$0
Community Solar Revenue		0		0	$248,884	($248,884)	$0
Revenue Adjustment - I&D Reserve		0		0	$3,923,938	($3,923,938)	$0
DSM		0		0	$27,070,370	($27,070,370)	$0
Blue Sky		0		0	$894,816	($894,816)	$0
Income Tax Deferral Adjustments		0		0	$1,495,307	($1,495,307)	$0
Unbilled		(53,125,000)	53,125,000	0	$504,000	$0	$504,000
Paperless Credit		0		0	$0	($1,639,965)	($1,639,965)
AGA		0		0	$12,386	$0	$12,386
Total Residential	**135,224**	**5,905,196,256**	**31,163,016**	**5,936,359,272**	**$706,439,053**	**$7,190,441**	**$713,629,494**
Commercial							
15	(446)	6,125,701	19,386	6,145,087	$730,861	($10,220)	$720,641
23	299,528	1,086,769,175	(36,585,258)	1,050,183,917	$128,990,377	($2,205,444)	$126,784,933
28	6,138,130	1,939,176,352	(2,406,578)	1,936,769,774	$179,140,980	($2,656,882)	$176,484,098
30	53,584,129	1,121,143,181	38,288,044	1,159,431,225	$90,044,234	($1,293,572)	$88,750,662
47	0	44,709,849	(2,051,173)	42,658,676	$4,359,971	($55,438)	$4,304,533
48	33,115,200	1,754,994,252	1,699,561,782	3,454,556,034	$110,901,029	($1,785,689)	$109,115,340
54	0	1,449,879	(76,217)	1,373,662	$138,294	($2,398)	$135,896
BPA Balancing Account		0		0	$1,620	($1,620)	$0
Solar Feed-In Revenue		0		0	$1,701,024	($1,701,024)	$0
Revenue Accounting Adjustment		0		0	$857,831	($857,831)	$0
Community Solar Revenue					$180,757	($180,757)	$0
Other Customer Retail Rev					$633,216	($633,216)	$0
Revenue Adjustment - I&D Reserve		0		0	$3,681,612	($3,681,612)	$0
DSM		0		0	$25,833,071	($25,833,071)	$0
Blue Sky		0		0	$1,090,180	($1,090,180)	$0
Income Tax Deferral Adjustments		0		0	$1,401,636	($1,401,636)	$0
Unbilled		80,639,000	(80,639,000)	0	$12,011,000	$0	$12,011,000
Paperless Credit		0		0	$0	($198,409)	($198,409)
AGA		0		0	$3,758,766	$0	$3,758,766
Total Commercial	**93,136,541**	**6,035,007,390**	**1,616,110,986**	**7,651,118,375**	**$565,456,459**	**($43,588,998)**	**$521,867,461**
Industrial							
15	(13)	245,865	1,594	247,459	$24,215	($464)	$23,752
23	106	18,616,845	(1,332,261)	17,284,584	$2,199,714	($41,028)	$2,158,686
28	51	79,375,858	(4,354,197)	75,021,661	$7,781,766	($132,539)	$7,649,227
30	38	181,501,493	(10,653,933)	170,847,560	$16,567,293	($263,290)	$16,304,003
47	0	960,000	(240,000)	720,000	$598,131	($2,578)	$595,553
48	43,484,000	1,265,432,180	(62,012,090)	1,203,420,090	$84,801,853	($1,486,875)	$83,314,978
BPA Balancing Account		0		0	$4	($4)	$0
Solar Feed-In Revenue		0		0	$417,730	($417,730)	$0
Revenue Accounting Adjustment		0		0	$353,728	($353,728)	$0
Community Solar Revenue		0		0	$46,694	($46,694)	$0
Other Customer Retail Rev		0		0	$150,467	($150,467)	$0
Revenue Adjustment - I&D Reserve		0		0	$1,105,570	($1,105,570)	$0
DSM		0		0	$6,881,779	($6,881,779)	$0
Blue Sky		0		0	$484,844	($484,844)	$0
Income Tax Deferral Adjustments		0		0	$378,958	($378,958)	$0
Unbilled		(17,477,000)	17,477,000	0	($403,000)	$0	($403,000)
Paperless Credit		0		0	$0	($3,337)	($3,337)
AGA		0		0	$104,987	$0	$104,987
Total Industrial	**43,484,182**	**1,528,655,241**	**(61,113,887)**	**1,467,541,354**	**$121,494,735**	**($11,749,885)**	**$109,744,849**
Irrigation							
41	25,174	171,439,514	63,470,016	234,909,530	$18,898,900	$533,501	$19,432,401
23	0	2,065	88	2,153	$416	$3	$418
48	0	17,571,812	1,562,599	19,134,411	$1,368,934	($17,400)	$1,351,534
BPA Balancing Account		0		0	$24,566	($24,566)	$0
BPA Adjustment		0		0	$28,223	($28,223)	$0
Demand Charge Accrual		0		0	$151,000	$0	$151,000
Solar Feed-In Revenue		0		0	$54,145	($54,145)	$0
Revenue Accounting Adjustment		0		0	($4,685)	$4,685	$0
Community Solar Revenue		0		0	$6,035	($6,035)	$0
Other Customer Retail Rev		0		0	$20,717	($20,717)	$0
Revenue Adjustment - I&D Reserve		0		0	$186,988	($186,988)	$0
DSM		0		0	$957,615	($957,615)	$0
Blue Sky		0		0	$373	($373)	$0
Income Tax Deferral Adjustments		0		0	$56,538	($56,538)	$0
Unbilled		4,735,000	(4,735,000)	0	$2,066,000	$0	$2,066,000
Paperless Credit		0		0	$0	($11,045)	($11,045)
AGA		0		0	$195,293	$0	$195,293
Total Irrigation	**25,174**	**193,748,391**	**60,297,703**	**254,046,094**	**$24,011,059**	**($825,457)**	**$23,185,602**
Lighting							
15	(2)	24,189	(24,189)	0	$3,635	($7)	$3,628
23	0	604,196	2,767	606,963	$145,279	$653	$145,932
51	(232)	23,584,025	(2,725,827)	20,858,198	$4,224,482	($76,268)	$4,148,214
53	(33)	8,075,045	746,215	8,821,260	$636,050	($12,381)	$623,669
Solar Feed-In Revenue		0		0	$734	($734)	$0
Revenue Accounting Adjustment		0		0	$8,189	($8,189)	$0
Community Solar Revenue		0		0	$257	($257)	$0
Other Customer Retail Rev		0		0	$3,278	($3,278)	$0
DSM		0		0	$148,778	($148,778)	$0
Income Tax Deferral Adjustments		0		0	$8,848	($8,848)	$0
Unbilled		(1,043,000)	1,043,000	0	($85,000)	$0	($85,000)
Paperless Credit		0		0	$0	($2,471)	($2,471)
AGA		0		0	$0	$0	$0
Total Lighting	**(267)**	**31,244,455**	**(958,034)**	**30,286,421**	**$5,094,531**	**($260,559)**	**$4,833,972**
TOTAL COMPANY	**136,780,854**	**13,693,851,732**	**1,645,499,784**	**15,339,351,516**	**$1,422,495,837**	**($49,234,459)**	**$1,373,261,378**

PacifiCorp
Oregon General Rate Case - December 2025
Historical 12 Months Ended June 2023; 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	($35,422)		$247,851	($16,826)	$231,024	($5,890)	$225,134
4	$5,059,502	($31,082,828)	$670,620,881	$63,983,585	$734,604,466	$51,025,767	$785,630,233
23	$103,048	($471,480)	$13,311,883	$936,495	$14,248,378	$919,369	$15,167,747
28	($265,969)	$0	$3,879,309	$206,301	$4,085,610	$911,175	$4,996,785
BPA Balancing Account	$0		$0		$0		$0
Solar Feed-In Revenue	$0		$0		$0		$0
Revenue Accounting Adjustment	$0		$0		$0		$0
Other Customer Retail Rev	$0		$0		$0		$0
Community 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		$504,000		$504,000	($504,000)	$0
Paperless Credit	$0		($1,639,965)	$0	($1,639,965)		($1,639,965)
AGA	$0		$12,386		$12,386		$12,386
Total Residential	**$4,861,159**	**($31,554,309)**	**$686,936,345**	**$65,109,555**	**$752,045,900**	**$52,346,421**	**$804,392,320**
Commercial							
15	($105,416)		$615,226	($41,863)	$573,363	$21,431	$594,794
23	$907,893	($2,181,215)	$125,511,611	$11,138,167	$136,649,778	$5,539,677	$142,189,455
28	($10,191,404)	($2,335,155)	$163,957,539	$17,136,810	$181,094,349	$17,466,087	$198,560,436
30	($5,050,371)	($916,184)	$82,784,107	$5,841,713	$88,625,820	$13,304,928	$101,930,748
47	$78,286		$4,382,819	$96,412	$4,479,231	$126,613	$4,605,844
48	$5,501,334	($1,761,917)	$112,854,756	$7,026,856	$119,881,612	$139,264,468	$259,146,080
54	($39,443)		$96,453	($5,868)	$90,585	($45)	$90,540
BPA Balancing Account	$0		$0		$0		$0
Solar Feed-In Revenue	$0		$0		$0		$0
Revenue Accounting Adjustment	$0		$0		$0		$0
Community 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		$12,011,000		$12,011,000	($12,011,000)	$0
Paperless Credit	$0		($198,409)	$0	($198,409)		($198,409)
AGA	$0		$3,758,766		$3,758,766		$3,758,766
Total Commercial	**($8,899,121)**	**($7,194,472)**	**$505,773,867**	**$41,192,227**	**$546,966,094**	**$163,712,159**	**$710,678,253**
Industrial							
15	($3,771)		$19,981	($1,349)	$18,632	$822	$19,453
23	$14,508	$0	$2,173,194	$186,966	$2,360,160	$10,458	$2,370,618
28	($455,868)	$0	$7,193,359	$305,499	$7,498,858	$278,239	$7,777,097
30	($699,044)		$15,604,959	$847,368	$16,452,327	$589,796	$17,042,123
47	$3,419		$598,972	($23,714)	$575,258	($132,740)	$442,518
48	$2,832,001		$86,146,979	$6,125,965	$92,272,944	$5,928,897	$98,201,841
BPA Balancing Account	$0		$0		$0		$0
Solar Feed-In Revenue	$0		$0		$0		$0
Revenue Accounting Adjustment	$0		$0		$0		$0
Community 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		($403,000)		($403,000)	$403,000	$0
Paperless Credit	$0		($3,337)	$0	($3,337)		($3,337)
AGA	$0		$104,987		$104,987		$104,987
Total Industrial	**$1,691,245**	**$0**	**$111,436,095**	**$7,440,735**	**$118,876,830**	**$7,078,472**	**$125,955,301**
Irrigation							
41	$3,504,852	($2,471,300)	$20,465,953	$2,063,873	$22,529,826	$10,157,067	$32,686,893
23	$0	$0	$418	$27	$445	$32	$477
48	$204,052	($126,280)	$1,429,306	$8,614	$1,437,920	$287,185	$1,725,105
BPA Balancing Account	$0		$0		$0		$0
BPA Adjustment	$0		$0		$0		$0
Demand Charge Accrual	($151,000)		$0		$0		$0
Solar Feed-In Revenue	$0		$0		$0		$0
Revenue Accounting Adjustment	$0		$0		$0		$0
Community 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		$2,066,000		$2,066,000	($2,066,000)	$0
Paperless Credit	$0		($11,045)	$0	($11,045)		($11,045)
AGA	$0		$195,293		$195,293		$195,293
Total Irrigation	**$3,557,904**	**($2,597,580)**	**$24,145,927**	**$2,072,513**	**$26,218,439**	**$8,378,284**	**$34,596,723**
Lighting							
15	($315)		$3,313	($379)	$2,934	($2,934)	$0
23	$662		$146,594	$5,696	$152,290	$6,216	$158,506
51	($712,305)		$3,435,909	($247,981)	$3,187,928	($285,231)	$2,902,697
53	($180,414)		$443,255	($23,008)	$420,247	$66,445	$486,692
Solar Feed-In Revenue	$0		$0		$0		$0
Revenue Accounting Adjustment	$0		$0		$0		$0
Community Solar Revenue	$0		$0		$0		$0
Other Customer Retail Rev	$0		$0		$0		$0
DSM	$0		$0		$0		$0
Income Tax Deferral Adjustments	$0		$0		$0		$0
Unbilled	$0		($85,000)		($85,000)	$85,000	$0
Paperless Credit	$0		($2,471)	$0	($2,471)		($2,471)
AGA	$0		$0		$0		$0
Total Lighting	**($892,372)**	**$0**	**$3,941,599**	**($265,672)**	**$3,675,928**	**($130,504)**	**$3,545,424**
TOTAL COMPANY	**$318,815**	**($41,346,361)**	**$1,332,233,832**	**$115,549,358**	**$1,447,783,191**	**$231,384,831**	**$1,679,168,022**

PacifiCorp
Oregon General Rate Case - December 2025
Pro Forma Revenue
Historical 12 Months Ended June 2023; Forecast 12 Months Ended December 2025
Revenue Adjustments

				Remove Tariff Riders												
	305 Booked Revenues	Remove Accounting Adjustments	Paperless Billing Credit Sch 300	Sch 98 BPA Adjust	Sch 94 WMVM Adjust	104 OCAT Adjust	190 WMP Adjust	192 Def. Acct. 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 206 PCAM Adjust	Sch 207 Com. Sol. Adjust	**Total Remove Tariff Riders**
Residential																
15	$283,410		$0	$4,754	($3,144)	($865)	($573)	$0	($127)	$147	($21)	($55)	($42)	($199)	($11)	($137)
4	$654,209,459		$1,604,367	$54,925,464	($5,911,450)	($1,891,589)	($562,676)	($638,827)	($2,018,835)	$2,031,356	($917,652)	($850,424)	($1,896,481)	($1,193,798)	($244,707)	$42,434,748
23	$12,986,776		$35,206	$903,873	($110,408)	($37,076)	($11,638)	($8,233)	($33,741)	$34,262	($13,893)	($13,728)	($28,779)	($19,329)	($2,977)	$693,539
28	$3,903,311		$392	$319,156	($23,908)	($11,529)	($2,377)	($935)	($12,021)	$11,451	($6,732)	($6,484)	($14,425)	($9,179)	($1,443)	$241,967
BPA Balancing Account	($531,705)			$531,705												$531,705
Solar Feed-In Revenue	$1,902,062	($1,902,062)														($1,902,062)
Revenue Accounting Adjustment	($1,056,099)	$1,056,099														$1,056,099
Other Customer Retail Rev	$592,139	($592,139)														($592,139)
Community Solar Revenue	$248,884	($248,884)														($248,884)
Revenue Adjustment - I&D Reserve	$3,923,938	($3,923,938)														($3,923,938)
DSM	$27,070,370	($27,070,370)														($27,070,370)
Blue Sky	$894,816	($894,816)														($894,816)
Income Tax Deferral Adjustments	$1,495,307	($1,495,307)														($1,495,307)
Unbilled	$504,000															$0
Paperless Credit	$0		($1,639,965)													($1,639,965)
AGA	$12,386															$0
Total Residential	**$706,439,053**	**($35,071,416)**	**$0**	**$56,684,951**	**($6,048,909)**	**($1,941,059)**	**($577,264)**	**($647,995)**	**($2,064,724)**	**$2,077,216**	**($938,299)**	**($870,690)**	**($1,939,728)**	**($1,222,505)**	**($249,138)**	**$7,190,441**
Commercial																
15	$730,861		$0	$3,396	($9,228)	($2,084)	($1,563)	$0	($377)	$594	($63)	($160)	($126)	($578)	($31)	($10,220)
23	$128,990,377		$171,699	$217,660	($1,150,998)	($355,168)	($132,211)	($94,197)	($378,143)	$404,002	($155,710)	($155,937)	($322,543)	($220,533)	($33,366)	($2,205,444)
28	$179,140,980		$24,123	$523,421	($932,559)	($504,381)	($110,217)	($40,839)	($495,674)	$486,404	($277,582)	($277,342)	($594,823)	($397,929)	($59,482)	($2,656,882)
30	$90,044,234		$2,097	$298,116	($373,567)	($248,639)	($46,000)	($13,057)	($262,862)	$253,545	($160,009)	($159,423)	($331,434)	($218,052)	($34,286)	($1,293,572)
47	$4,359,971		$6	$0	($7,475)	($15,358)	($690)	($388)	($9,022)	$10,304	($5,864)	($5,749)	($12,180)	($7,668)	($1,353)	($55,438)
48	$110,901,029		$306	$343,952	($431,051)	($303,341)	($30,620)	($19,005)	($356,868)	$341,749	($231,964)	($240,650)	($481,771)	($322,895)	($53,530)	($1,785,689)
54	$138,294		$180	$0	($1,560)	($413)	($144)	$0	($331)	$386	($86)	($126)	($173)	($102)	($29)	($2,398)
BPA Balancing Account	$1,620			($1,620)												($1,620)
Solar Feed-In Revenue	$1,701,024	($1,701,024)														($1,701,024)
Revenue Accounting Adjustment	$857,831	($857,831)														($857,831)
Community Solar Revenue	$180,757	($180,757)														($180,757)
Other Customer Retail Rev	$633,216	($633,216)														($633,216)
Revenue Adjustment - I&D Reserve	$3,681,612	($3,681,612)														($3,681,612)
DSM	$25,833,071	($25,833,071)														($25,833,071)
Blue Sky	$1,090,180	($1,090,180)														($1,090,180)
Income Tax Deferral Adjustments	$1,401,636	($1,401,636)														($1,401,636)
Unbilled	$12,011,000															$0
Paperless Credit	$0		($198,409)													($198,409)
AGA	$3,758,766															$0
Total Commercial	**$565,456,459**	**($35,379,326)**	**$0**	**$1,384,925**	**($2,906,438)**	**($1,429,385)**	**($321,445)**	**($167,486)**	**($1,503,276)**	**$1,496,984**	**($831,279)**	**($839,386)**	**($1,743,049)**	**($1,167,757)**	**($182,079)**	**($43,588,998)**
Industrial																
15	$24,215		$0	$6	($325)	($69)	($52)	$0	($13)	$22	($2)	($6)	($4)	($20)	($1)	($464)
23	$2,199,714		$2,031	$1,329	($20,250)	($5,775)	($2,134)	($1,554)	($6,346)	$6,493	($2,613)	($2,589)	($5,413)	($3,646)	($560)	($41,028)
28	$7,781,766		$765	$272	($38,467)	($21,492)	($4,569)	($1,748)	($19,990)	$19,040	($11,194)	($11,625)	($23,988)	($17,145)	($2,399)	($132,539)
30	$16,567,293		$278	$0	($60,662)	($45,687)	($6,979)	($2,095)	($41,383)	$38,470	($25,190)	($25,410)	($52,179)	($37,054)	($5,398)	($263,290)
47	$598,131		$6	$0	($127)	($1,920)	$0	($4)	($192)	$220	($125)	($80)	($259)	($68)	($29)	($2,578)
48	$84,801,853		$257	$0	($262,387)	($233,398)	($26,519)	($11,760)	($253,840)	$245,584	($164,996)	($169,302)	($342,684)	($229,754)	($38,076)	($1,486,875)
BPA Balancing Account	$4			($4)												($4)
Solar Feed-In Revenue	$417,730	($417,730)														($417,730)
Revenue Accounting Adjustment	$353,728	($353,728)														($353,728)
Community Solar Revenue	$46,694	($46,694)														($46,694)
Other Customer Retail Rev	$150,467	($150,467)														($150,467)
Revenue Adjustment - I&D Reserve	$1,105,570	($1,105,570)														($1,105,570)
DSM	$6,881,779	($6,881,779)														($6,881,779)
Blue Sky	$484,844	($484,844)														($484,844)
Income Tax Deferral Adjustments	$378,958	($378,958)														($378,958)
Unbilled	($403,000)															$0
Paperless Credit	$0		($3,337)													($3,337)
AGA	$104,987															$0
Total Industrial	**$121,494,735**	**($9,819,771)**	**$0**	**$1,603**	**($382,219)**	**($308,340)**	**($40,253)**	**($17,161)**	**($321,765)**	**$309,831**	**($204,121)**	**($209,012)**	**($424,528)**	**($287,687)**	**($46,463)**	**($11,749,885)**
Irrigation																
41	$18,898,900		$11,039	$897,737	($93,494)	($79,369)	($63,327)	($8,156)	($66,887)	$99,433	($26,755)	($30,850)	($53,510)	($46,628)	($5,733)	$533,501
23	$416		$6	$0	($0)	($2)	($0)	($0)	($1)	$1	($0)	($0)	($1)	($0)	($0)	$3
48	$1,368,934		$0	$0	($901)	($5,942)	($68)	($102)	($3,865)	$5,722	($2,513)	($1,881)	($5,218)	($2,052)	($580)	($17,400)
BPA Balancing Account	$24,566			($24,566)												($24,566)
BPA Adjustment	$28,223			($28,223)												($28,223)
Demand Charge Accrual	$151,000															$0
Solar Feed-In Revenue	$54,145	($54,145)														($54,145)
Revenue Accounting Adjustment	($4,685)	$4,685														$4,685
Community Solar Revenue	$6,035	($6,035)														($6,035)
Other Customer Retail Rev	$20,717	($20,717)														($20,717)
Revenue Adjustment - I&D Reserve	$186,988	($186,988)														($186,988)
DSM	$957,615	($957,615)														($957,615)
Blue Sky	$373	($373)														($373)
Income Tax Deferral Adjustments	$56,538	($56,538)														($56,538)
Unbilled	$2,066,000															$0
Paperless Credit	$0		($11,045)													($11,045)
AGA	$195,293															$0
Total Irrigation	**$24,011,059**	**($1,277,727)**	**$0**	**$844,949**	**($94,395)**	**($85,313)**	**($63,395)**	**($8,257)**	**($70,753)**	**$105,156**	**($29,268)**	**($32,731)**	**($58,729)**	**($48,680)**	**($6,313)**	**($825,457)**
Lighting																
15	$3,635		$0	$19	($10)	($20)	$0	$0	($1)	$6	($0)	($0)	($0)	$0	($0)	($7)
23	$145,279		$2,471	$0	($661)	($376)	($151)	($71)	($205)	$195	($85)	($105)	($175)	($166)	($18)	$653
51	$4,224,482		$0	$0	($51,579)	($11,819)	($9,516)	$0	($2,672)	$4,452	($364)	($991)	($729)	($2,868)	($182)	($76,268)
53	$636,050		$0	$0	($6,773)	($1,776)	($1,018)	$0	($1,379)	$1,608	($487)	($763)	($974)	($738)	($81)	($12,381)
Solar Feed-In Revenue	$734	($734)														($734)
Revenue Accounting Adjustment	$8,189	($8,189)														($8,189)
Community Solar Revenue	$257	($257)														($257)
Other Customer Retail Rev	$3,278	($3,278)														($3,278)
DSM	$148,778	($148,778)														($148,778)
Income Tax Deferral Adjustments	$8,848	($8,848)														($8,848)
Unbilled	($85,000)															$0
Paperless Credit	$0		($2,471)													($2,471)
AGA	$0															$0
Total Lighting	**$5,094,531**	**($170,084)**	**$0**	**$19**	**($59,022)**	**($13,991)**	**($10,685)**	**($71)**	**($4,258)**	**$6,261**	**($936)**	**($1,860)**	**($1,878)**	**($3,773)**	**($282)**	**($260,559)**
TOTAL COMPANY	**$1,422,495,837**	**($81,718,325)**	**$0**	**$58,916,447**	**($9,490,983)**	**($3,778,087)**	**($1,013,042)**	**($840,969)**	**($3,964,777)**	**$3,995,447**	**($2,003,902)**	**($1,953,680)**	**($4,167,912)**	**($2,730,402)**	**($484,273)**	**($49,234,459)**

PacifiCorp
Oregon General Rate Case - December 2025
Pro Forma Revenue
Historical 12 Months Ended June 2023; Forecast '
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	$283,273		($35,530)	$108	($35,422)		$247,851	($16,826)	($16,826)	$231,024	$6,696	($12,587)	($5,890)	$225,134
4	$696,644,207		$5,839,234	($779,732)	$5,059,502	($31,082,828)	$670,620,881	$63,983,585	$63,983,585	$734,604,466	$56,772,645	($5,746,878)	$51,025,767	$785,630,233
23	$13,680,315		$106,906	($3,858)	$103,048	($471,480)	$13,311,883	$936,495	$936,495	$14,248,378	$899,584	$19,785	$919,369	$15,167,747
28	$4,145,278		($246,435)	($19,534)	($265,969)		$3,879,309	$206,301	$206,301	$4,085,610	$434,723	$476,452	$911,175	$4,996,785
BPA Balancing Account	$0				$0		$0			$0			$0	$0
Solar Feed-In Revenue	$0				$0		$0			$0			$0	$0
Revenue Accounting Adjustment	$0				$0		$0			$0			$0	$0
Other Customer Retail Rev	$0				$0		$0			$0			$0	$0
Community 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	$504,000				$0		$504,000			$504,000		($504,000)	($504,000)	$0
Paperless Credit	($1,639,965)				$0		($1,639,965)			($1,639,965)			$0	($1,639,965)
AGA	$12,386				$0		$12,386			$12,386			$0	$12,386
Total Residential	**$713,629,494**	**$0**	**$5,664,175**	**($803,016)**	**$4,861,159**	**($31,554,309)**	**$686,936,345**	**$65,109,555**	**$65,109,555**	**$752,045,900**	**$58,113,648**	**($5,767,228)**	**$52,346,421**	**$804,392,320**
Commercial														
15	$720,641		($104,703)	($713)	($105,416)		$615,226	($41,863)	($41,863)	$573,363	$19,552	$1,879	$21,431	$594,794
23	$126,784,933		$1,139,995	($232,102)	$907,893	($2,181,215)	$125,511,611	$11,138,167	$11,138,167	$136,649,778	$9,971,086	($4,431,409)	$5,539,677	$142,189,455
28	$176,484,098		($10,064,231)	($127,173)	($10,191,404)	($2,335,155)	$163,957,539	$17,136,810	$17,136,810	$181,094,349	$17,623,985	($157,898)	$17,466,087	$198,560,436
30	$88,750,662		($5,258,253)	$207,882	($5,050,371)	($916,184)	$82,784,107	$5,841,713	$5,841,713	$88,625,820	$9,998,735	$3,306,193	$13,304,928	$101,930,748
47	$4,304,533		$115,819	($37,533)	$78,286		$4,382,819	$96,412	$96,412	$4,479,231	$344,401	($217,788)	$126,613	$4,605,844
48	$109,115,340		$4,910,992	$590,342	$5,501,334	($1,761,917)	$112,854,756	$7,026,856	$7,026,856	$119,881,612	$14,657,191	$124,607,277	$139,264,468	$259,146,080
54	$135,896		($40,060)	$617	($39,443)		$96,453	($5,868)	($5,868)	$90,585	$4,538	($4,583)	($45)	$90,540
BPA Balancing Account	$0				$0		$0			$0			$0	$0
Solar Feed-In Revenue	$0				$0		$0			$0			$0	$0
Revenue Accounting Adjustment	$0				$0		$0			$0			$0	$0
Community 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	$12,011,000				$0		$12,011,000			$12,011,000		($12,011,000)	($12,011,000)	$0
Paperless Credit	($198,409)				$0		($198,409)			($198,409)			$0	($198,409)
AGA	$3,758,766				$0		$3,758,766			$3,758,766			$0	$3,758,766
Total Commercial	**$521,867,461**	**$0**	**($9,300,441)**	**$401,320**	**($8,899,121)**	**($7,194,472)**	**$505,773,867**	**$41,192,227**	**$41,192,227**	**$546,966,094**	**$52,619,488**	**$111,092,671**	**$163,712,159**	**$710,678,253**
Industrial														
15	$23,752		($3,722)	($49)	($3,771)		$19,981	($1,349)	($1,349)	$18,632	$699	$122	$822	$19,453
23	$2,158,686		$20,088	($5,580)	$14,508	$0	$2,173,194	$186,966	$186,966	$2,360,160	$171,077	($160,619)	$10,458	$2,370,618
28	$7,649,227		($409,486)	($46,382)	($455,868)	$0	$7,193,359	$305,499	$305,499	$7,498,858	$720,292	($442,053)	$278,239	$7,777,097
30	$16,304,003		($836,279)	$137,235	($699,044)		$15,604,959	$847,368	$847,368	$16,452,327	$1,618,560	($1,028,764)	$589,796	$17,042,123
47	$595,553		$3,419	$0	$3,419		$598,972	($23,714)	($23,714)	$575,258	$7,486	($140,226)	($132,740)	$442,518
48	$83,314,978		$3,056,714	($224,713)	$2,832,001		$86,146,979	$6,125,965	$6,125,965	$92,272,944	$10,862,804	($4,933,907)	$5,928,897	$98,201,841
BPA Balancing Account	$0				$0		$0			$0			$0	$0
Solar Feed-In Revenue	$0				$0		$0			$0			$0	$0
Revenue Accounting Adjustment	$0				$0		$0			$0			$0	$0
Community 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	($403,000)				$0		($403,000)			($403,000)		$403,000	$403,000	$0
Paperless Credit	($3,337)				$0		($3,337)			($3,337)			$0	($3,337)
AGA	$104,987				$0		$104,987			$104,987			$0	$104,987
Total Industrial	**$109,744,849**	**$0**	**$1,830,734**	**($139,489)**	**$1,691,245**	**$0**	**$111,436,095**	**$7,440,735**	**$7,440,735**	**$118,876,830**	**$13,380,918**	**($6,302,447)**	**$7,078,472**	**$125,955,301**
Irrigation														
41	$19,432,401		$2,875,678	$629,174	$3,504,852	($2,471,300)	$20,465,953	$2,063,873	$2,063,873	$22,529,826	$1,505,239	$8,651,828	$10,157,067	$32,686,893
23	$418		$0	$0	$0		$418	$27	$27	$445	$20	$12	$32	$477
48	$1,351,534		$77,704	$126,348	$204,052	($126,280)	$1,429,306	$8,614	$8,614	$1,437,920	$149,379	$137,806	$287,185	$1,725,105
BPA Balancing Account	$0				$0		$0			$0			$0	$0
BPA Adjustment	$0				$0		$0			$0			$0	$0
Demand Charge Accrual	$151,000	($151,000)			($151,000)		$0			$0			$0	$0
Solar Feed-In Revenue	$0				$0		$0			$0			$0	$0
Revenue Accounting Adjustment	$0				$0		$0			$0			$0	$0
Community 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	$2,066,000				$0		$2,066,000			$2,066,000		($2,066,000)	($2,066,000)	$0
Paperless Credit	($11,045)				$0		($11,045)			($11,045)			$0	($11,045)
AGA	$195,293				$0		$195,293			$195,293			$0	$195,293
Total Irrigation	**$23,185,602**	**($151,000)**	**$2,953,382**	**$755,522**	**$3,557,904**	**($2,597,580)**	**$24,145,927**	**$2,072,513**	**$2,072,513**	**$26,218,439**	**$1,654,638**	**$6,723,646**	**$8,378,284**	**$34,596,723**
Lighting														
15	$3,628		($300)	($15)	($315)		$3,313	($379)	($379)	$2,934	$100	($3,034)	($2,934)	$0
23	$145,932		$697	($35)	$662		$146,594	$5,696	$5,696	$152,290	$5,885	$331	$6,216	$158,506
51	$4,148,214		($685,047)	($27,258)	($712,305)		$3,435,909	($247,981)	($247,981)	$3,187,928	$94,141	($379,372)	($285,231)	$2,902,697
53	$623,669		($178,193)	($2,222)	($180,414)		$443,255	($23,008)	($23,008)	$420,247	$25,275	$41,169	$66,445	$486,692
Solar Feed-In Revenue	$0				$0		$0			$0			$0	$0
Revenue Accounting Adjustment	$0				$0		$0			$0			$0	$0
Community Solar Revenue	$0				$0		$0			$0			$0	$0
Other Customer Retail Rev	$0				$0		$0			$0			$0	$0
DSM	$0				$0		$0			$0			$0	$0
Income Tax Deferral Adjustments	$0				$0		$0			$0			$0	$0
Unbilled	($85,000)				$0		($85,000)			($85,000)		$85,000	$85,000	$0
Paperless Credit	($2,471)				$0		($2,471)			($2,471)			$0	($2,471)
AGA	$0				$0		$0			$0			$0	$0
Total Lighting	**$4,833,972**	**$0**	**($862,842)**	**($29,530)**	**($892,372)**	**$0**	**$3,941,599**	**($265,672)**	**($265,672)**	**$3,675,928**	**$125,401**	**($255,905)**	**($130,504)**	**$3,545,424**
TOTAL COMPANY	**$1,373,261,378**	**($151,000)**	**$285,008**	**$184,807**	**$318,815**	**($41,346,361)**	**$1,332,233,832**	**$115,549,358**	**$115,549,358**	**$1,447,783,191**	**$125,894,094**	**$105,490,737**	**$231,384,831**	**$1,679,168,022**

PacifiCorp
Oregon General Rate Case - December 2025
Confidential REC Revenues

PAGE 3.2_REDACTED

Note: Please see Confidential Exhibit PAC/1706_CONF for redacted information.

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Revenue:							
Remove:							
June 2023 Booked Revenues (Including Accruals)	456	1	(9,264,656)	SG	26.884%	(2,490,725)	3.2.1
June 2023 REC Deferrals	456	1	3,203,428	SG	26.884%	861,215	3.2.1
June 2023 Leaning Juniper Indemnity	456	1	21,449	SG	26.884%	5,766	3.2.1
Add December 2025 Forecasted REC Revenues	456	3	[redacted]	SG	26.884%	[redacted]	3.2.2

Description of Adjustment:

This adjustment removes REC revenue and REC deferrals booked during the 12 months ended June 2023. 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. REC revenues received through Schedule 272 are added back into Test Year results on a forecast basis.

PacifiCorp
Oregon General Rate Case - December 2025
Confidential REC Revenues
Actuals as Booked

Posting Date	Fin Accrual	Fin Reversal	Back Office Actual	Kennecott Removal	NET Rec Revenue
FERC Acct (Ref B1)	4562700	4562700	4562700	4562700	
SAP Acct	301944	301944	301945	301945	
July-22	(385,881)	424,953	(408,834)	50,000	(319,762)
August-22	(391,563)	385,881	(52,146)	50,000	(7,828)
September-22	(50,000)	391,563	(50,000)	50,000	341,563
October-22	(50,000)	50,000	(50,000)	50,000	-
November-22	(50,000)	50,000	(50,000)	50,000	-
December-22	(50,000)	50,000	(1,275,000)	50,000	(1,225,000)
January-23	(50,587)	50,000	(50,000)	50,000	(587)
February-23	(1,672,998)	50,587	(394,000)	50,000	(1,966,410)
March-23	(3,579,650)	1,672,998	(2,030,916)	50,000	(3,887,569)
April-23	(1,644,301)	3,579,650	(3,578,638)	50,000	(1,593,288)
May-23	(659,338)	1,644,301	(1,646,670)	50,000	(611,707)
June-23	(51,366)	659,338	(652,040)	50,000	5,932
12 ME June 2023 Total	(8,635,683)	9,009,270	(10,238,244)	600,000	(9,264,656)

REC Deferrals Included in Unadjusted Results:

FERC Account	4562700	
Amount Yr. Ended June 2023	**3,203,428**	**Ref. 3.2**

Leaning Juniper indemnity REC revenue included in unadjusted results:

FERC Account	4562700	
Amount Yr. Ended June 2023	**21,449**	**Ref. 3.2**

PacifiCorp
Oregon General Rate Case - December 2025
Confidential REC Revenues
Pryor Mountain REC Revenues
Calendar Year 2025 Forecast

Note: Please see Confidential Exhibit PAC/1706_CONF for redacted information.

Posting Date	Pryor Mountain REC Forecast	
January-25	[redacted]	
February-25		
March-25		
April-25		
May-25		
June-25		
July-25		
August-25		
September-25		
October-25		
November-25		
December-25		
12 ME December 2025 Total		**Ref. 3.2**

PacifiCorp
Oregon General Rate Case - December 2025
Wheeling Revenue

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Revenue:							
Other Electric Revenues	456	1	(21,179,367)	SG	26.884%	(5,693,894)	3.3.2
Other Electric Revenues	456	1	4,674,238	SE	26.339%	1,231,153	3.3.2
Other Electric Revenues	456	2	1,646,196	SG	26.884%	442,566	3.3.2
Other Electric Revenues	456	3	31,722,057	SG	26.884%	8,528,208	3.3.2
			16,863,125			4,508,033	
Adjustment Detail:							
Actual Wheeling Revenues 12 ME June 2023			181,740,192				3.3.2
Total Adjustments			16,863,125				Above
Adjusted Wheeling Revenues 12 ME December 2025			198,603,317				3.3.2

Description of Adjustment:

This adjustment removes out-of-period and one-time adjustments from wheeling revenues recorded in 12 months ended June 2023 and adds in pro forma changes through December 2025.

PacifiCorp
Oregon General Rate Case - December 2025
Wheeling Revenue

Customer	Total
3 Phase Renewables	5
Airport Solar LLC	(2,192,009)
Altop Energy Trading LLC	(267)
Arizona Electric Power Cooperative, Inc.	(1,908)
Arizona Public Service Company	(71,477)
Avangrid Renewables, LLC	(6,064,628)
Avista	(141)
Basin Electric Power Cooperative	(2,217,746)
BHG	(6,810)
Black Hills Corporation	(3,861,079)
Black Hills/Colorado Electric Utility Company	(594)
Bonneville Power Administration	(24,814,036)
Brookfield Renewable Trading & Marketing LP	(461,882)
Calpine Energy Solutions	(782,257)
City of Roseville	(1,809,567)
Clatskanie Peoples Utility District	(591,354)
Conoco Phillips Company	(15,982)
Constellation Energy Generation, LLC (ESS)	(30,413)
Constellation Energy Generation, LLC (Stateline)	(14,154,538)
CP Energy Marketing (US) Inc.	(18,207)
Deseret Generation & Trans.	(7,509,142)
Dynasty Power Inc.	(2,586,689)
EDF Trading North America, LLC	(348,886)
Energy Keepers, Inc	(621,822)
Evergreen Biopower	(441,805)
Fall River Rural Electric Cooperative	(151,308)
Falls Creek H.P. LP	(180,384)
Garrett Solar LLC	(458,279)
Guzman Energy, LLC	(3,402,365)
Idaho Power Company	(4,140,622)
Idaho Power Company - Power Supply Merchant	410,105
Imperial Irrigation District	(675,555)
Macquarie Energy, LLC	(2,321,146)
MAG Energy Solutions, Inc.	(346,322)
Mercuria Energy America, LLC	(2,071,680)
Moon Lake Electric Association	(20,424)
Morgan Stanley	(2,919,830)
Navajo Tribal Utility Authority	(201,961)
Nevada Power Company	(130,338)
NextEra Energy Resources, LLC	(2,919,243)
Pacific Gas & Electric Company	(12,627)
PACIFICORP TRANSFER	(0)
Portland General Electric Company	(125,718)
Powerex Corporation	(45,457,792)
Public Services Company of Colorado	(23,556)
Rainbow Energy Marketing	(2,116,371)

PacifiCorp
Oregon General Rate Case - December 2025
Wheeling Revenue

Customer	Total
Sacramento Municipal Utility District	(749,049)
Salt River Project	(989,991)
Shell Energy North America	(4,411,450)
Sierra Pacific Power Company	(36,159)
Southern California Edison Company	(4,284,021)
Southern California Public Power Authority	(55,077)
State of South Dakota	(157,695)
Tenaska Power Services Co	(571,932)
The Energy Authority, Inc.	(1,336,764)
Thermo No. 1 BE-01, LLC	(486,509)
TransAlta Energy Marketing (U.S.) Inc.	(1,062,516)
Tri-State Generation & Trans.	(729,984)
U.S. Bureau of Reclamation CR	(10,961)
U.S. Bureau of Reclamation FNO	(21,241)
U.S. Bureau of Reclamation WB	(23,710)
Uniper Global Commodities North America LLC	(538,405)
Utah Associated Municipal Power Systems	(25,156,017)
Utah Municipal Power Agency	(4,725,493)
Vitol Inc.	(1,291,984)
Warm Springs Power Enterprises	(119,700)
Western Area Power Adm CO River	(2,064)
Western Area Power Adm FNO	(89,141)
Western Area Power Adm LAP	(275,439)
Western Area Power Administration	(2,911,836)
SAP Adjustments	4,165,598
Total	**(181,740,192)**
	Ref 3.3

Type		
1	Remove refunds and other out of period adjustments	16,505,128
2	Annualized Changes	(1,646,196)
3	Proforma Adjustments	(31,722,057)

Incremental Adjustments	**(16,863,125)**
	Ref 3.3
Accum Totals	**(198,603,317)**
	Ref 3.3

PacifiCorp
Oregon General Rate Case December 2025
Fly Ash Revenue

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Revenue:							
Fly Ash Revenue	456	3	(5,179,536)	SG	26.884%	(1,392,474)	Below

Adjustment Detail:

12 Months Ended June 2023	14,065,194
12 Months Ending December 2025	8,885,658
Total Adjustment	(5,179,536)

Description of Adjustment:

This adjustment walks forward the level of fly ash sales revenue from the June 2023 Base Period to the December 2025 Test Period.

Tab 4 - Operation & Maintenance Expense

Oregon General Rate Case – December 2025

Operation & Maintenance Expense Adjustment Index

The Company's June 2023 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 2025 test period. The following adjustments are included:

4.1 Miscellaneous General Expense & Revenue
4.2 Confidential Wages & Employee Benefits
4.3 Pension Related Non-Service Expense
4.4 Remove Non-Recurring Entries
4.5 Insurance Expense
4.6 Generation Overhaul Expense
4.7 Revenue Sensitive Items & Uncollectible Accounts
4.8 Memberships & Subscriptions
4.9 Meals and Entertainment Adjustment
4.10 O&M Escalation
4.11 Wildfire & Vegetation Management O&M
4.12 Customer Payment Fees
4.13 Incremental O&M

PacifiCorp
Oregon General Rate Case - December 2025
Tab 4 Adjustment Summary

		Total Adjustments	4.1 Miscellaneous General Expense & Revenue	4.2 Wage & Employee Benefits	4.3 Pension Related Non-Service Expense	4.4 Remove Non-Recurring Entries	4.5 Insurance Expense	4.6 Generation Overhaul Expense
1	Operating ReWenues:							
2	General Business ReWenues	1,769,316	1,769,316	-	-	-	-	-
3	Interdepartmental	-	-	-	-	-	-	-
4	Special Sales	-	-	-	-	-	-	-
5	Other Operating ReWenues	-	-	-	-	-	-	-
6	Total Operating ReWenues	1,769,316	1,769,316	-	-	-	-	-
7								
8	Operating Expenses:							
9	Steam Production	354,350	(2,240)	1,663,183	-	-	-	535,268
10	Nuclear Production	-	-	-	-	-	-	-
11	Hydro Production	2,706,114	-	390,421	-	1,985,433	-	-
12	Other Power Supply	2,671,783	256,891	661,828	-	-	-	761,814
13	Transmission	(1,931,955)	-	634,188	-	-	-	-
14	Distribution	9,263,977	-	3,236,611	-	-	-	-
15	Customer Accounting	7,431,387	(9,820)	576,983	-	-	-	-
16	Customer SerWice & Info	391,763	209,228	205,152	-	-	-	-
17	Sales	-	-	-	-	-	-	-
18	AdministratiWe & General	(110,837,989)	434,876	427,567	(8,432,127)	-	(105,258,061)	-
19								
20	Total O&M Expenses	(89,950,571)	888,935	7,795,932	(8,432,127)	1,985,433	(105,258,061)	1,297,082
21								
22	Depreciation	-	-	-	-	-	-	-
23	Amortization	-	-	-	-	-	-	-
24	Taxes Other Than Income	6,690,549	-	-	-	-	-	-
25	Income Taxes - Federal	17,957,678	172,307	(1,563,732)	1,691,342	(398,244)	22,019,501	(260,173)
26	Income Taxes - State	4,066,917	39,023	(354,142)	383,042	(90,191)	4,986,807	(58,922)
27	Income Taxes - Def Net	(1,865,118)	-	-	-	-	(1,865,118)	-
28	InWestment Tax Credit Adj.	-	-	-	-	-	-	-
29	Misc ReWenue & Expense	19,995	19,995	-	-	-	-	-
30								
31	Total Operating Expenses:	(63,080,549)	1,120,260	5,878,058	(6,357,743)	1,496,997	(80,116,871)	977,987
32								
33	Operating ReW For Return:	64,849,865	649,056	(5,878,058)	6,357,743	(1,496,997)	80,116,871	(977,987)
34								
35	Rate Base:							
36	Electric Plant In SerWice	-	-	-	-	-	-	-
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	(1,832,030)	32,918	175,859	(190,210)	44,787	(2,341,121)	29,259
45	Weatherization Loans	-	-	-	-	-	-	-
46	Misc Rate Base	-	-	-	-	-	-	-
47								
48	Total Electric Plant:	(1,832,030)	32,918	175,859	(190,210)	44,787	(2,341,121)	29,259
49								
50	Rate Base Deductions:							
51	Accum ProW For Deprec	-	-	-	-	-	-	-
52	Accum ProW For Amort	-	-	-	-	-	-	-
53	Accum Def Income Tax	(38,564,469)	-	-	-	-	(38,564,469)	-
54	Unamortized ITC	-	-	-	-	-	-	-
55	Customer AdW For Const	-	-	-	-	-	-	-
56	Customer SerWice Deposits	-	-	-	-	-	-	-
57	Misc Rate Base Deductions	156,851,573	-	-	-	-	156,851,573	-
58								
59	Total Rate Base Deductions	118,287,105	-	-	-	-	118,287,105	-
60								
61	Total Rate Base:	116,455,075	32,918	175,859	(190,210)	44,787	115,945,984	29,259
62								
63	Return on Rate Base	1.155%	0.013%	-0.123%	0.133%	-0.031%	1.466%	-0.020%
64								
65	Return on Equity	2.310%	0.027%	-0.245%	0.265%	-0.062%	2.933%	-0.040%
66								
67	TAX CALCULATION:							
68	Operating ReWenue	85,009,343	860,387	(7,795,932)	8,432,127	(1,985,433)	105,258,061	(1,297,082)
69	Other Deductions	-	-	-	-	-	-	-
70	Interest (AFUDC)	-	-	-	-	-	-	-
71	Interest	3,015,583	852	4,554	(4,925)	1,160	3,002,400	758
72	Schedule "M" Additions	7,585,912	-	-	-	-	7,585,912	-
73	Schedule "M" Deductions	-	-	-	-	-	-	-
74	Income Before Tax	89,579,671	859,534	(7,800,486)	8,437,053	(1,986,592)	109,841,572	(1,297,840)
75								
76	State Income Taxes	4,066,917	39,023	(354,142)	383,042	(90,191)	4,986,807	(58,922)
77	Taxable Income	85,512,754	820,511	(7,446,344)	8,054,011	(1,896,401)	104,854,765	(1,238,918)
78								
79	Federal Income Taxes + Other	17,957,678	172,307	(1,563,732)	1,691,342	(398,244)	22,019,501	(260,173)
	APPROXIMATE PRICE CHANGE	(76,613,297)	(887,160)	8,081,755	(8,741,274)	2,058,224	(97,587,951)	1,344,637

PacifiCorp
Oregon General Rate Case - December 202
Tab 4 Adjustment Summary

	4.7 Revenue Sensitive Items & Uncollectible Accounts	4.8 Memberships and Subscriptions	4.9 Meals and Entertainment Adjustment	4.10 O&M Escalation	4.11 Wildfire and Vegetation Management O&M	4.12 Customer Payment Fees	4.13 Incremental O&M
1 Operating ReWenues:							
2 General Business ReWenues	-	-	-	-	-	-	-
3 Interdepartmental	-	-	-	-	-	-	-
4 Special Sales	-	-	-	-	-	-	-
5 Other Operating ReWenues	-	-	-	-	-	-	-
6 Total Operating ReWenues	-	-	-	-	-	-	-
7							
8 Operating Expenses:							
9 Steam Production	-	-	(7,536)	1,092,285	-	-	(2,926,609)
10 Nuclear Production	-	-	-	-	-	-	-
11 Hydro Production	-	-	(4,640)	76,003	-	-	258,897
12 Other Power Supply	-	-	(16,027)	1,007,277	-	-	-
13 Transmission	-	-	(4,442)	(102,995)	(2,458,706)	-	-
14 Distribution	-	-	(41,565)	633,634	5,435,297	-	-
15 Customer Accounting	1,717,034	-	(2,357)	340,993	-	4,808,555	-
16 Customer SerWice & Info	-	-	(10,588)	(12,029)	-	-	-
17 Sales	-	-	-	-	-	-	-
18 AdministratiWe & General	1,203,250	(172,095)	(73,906)	1,032,506	-	-	-
19							
20 Total O&M Expenses	2,920,284	(172,095)	(161,060)	4,067,673	2,976,591	4,808,555	(2,667,712)
21							
22 Depreciation	-	-	-	-	-	-	-
23 Amortization	-	-	-	-	-	-	-
24 Taxes Other Than Income	6,690,549	-	-	-	-	-	-
25 Income Taxes - Federal	(1,927,771)	34,519	32,306	(815,906)	(597,054)	(964,515)	535,098
26 Income Taxes - State	(436,587)	7,818	7,316	(184,780)	(135,216)	(218,436)	121,185
27 Income Taxes - Def Net	-	-	-	-	-	-	-
28 InWestment Tax Credit Adj.	-	-	-	-	-	-	-
29 Misc ReWenue & Expense	-	-	-	-	-	-	-
30							
31 Total Operating Expenses:	7,246,476	(129,758)	(121,438)	3,066,986	2,244,321	3,625,604	(2,011,430)
32							
33 Operating ReW For Return:	(7,246,476)	129,758	121,438	(3,066,986)	(2,244,321)	(3,625,604)	2,011,430
34							
35 Rate Base:							
36 Electric Plant In SerWice	-	-	-	-	-	-	-
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	216,799	(3,882)	(3,633)	91,758	67,145	108,470	(60,178)
45 Weatherization Loans	-	-	-	-	-	-	-
46 Misc Rate Base	-	-	-	-	-	-	-
47							
48 Total Electric Plant:	216,799	(3,882)	(3,633)	91,758	67,145	108,470	(60,178)
49							
50 Rate Base Deductions:							
51 Accum ProW For Deprec	-	-	-	-	-	-	-
52 Accum ProW For Amort	-	-	-	-	-	-	-
53 Accum Def Income Tax	-	-	-	-	-	-	-
54 Unamortized ITC	-	-	-	-	-	-	-
55 Customer AdW For Const	-	-	-	-	-	-	-
56 Customer SerWice Deposits	-	-	-	-	-	-	-
57 Misc Rate Base Deductions	-	-	-	-	-	-	-
58							
59 Total Rate Base Deductions	-	-	-	-	-	-	-
60							
61 Total Rate Base:	216,799	(3,882)	(3,633)	91,758	67,145	108,470	(60,178)
62							
63 Return on Rate Base	-0.148%	0.003%	0.002%	-0.062%	-0.046%	-0.074%	0.041%
64							
65 Return on Equity	-0.295%	0.005%	0.005%	-0.125%	-0.091%	-0.148%	0.082%
66							
67 TAX CALCULATION:							
68 Operating ReWenue	(9,610,834)	172,095	161,060	(4,067,673)	(2,976,591)	(4,808,555)	2,667,712
69 Other Deductions	-	-	-	-	-	-	-
70 Interest (AFUDC)	-	-	-	-	-	-	-
71 Interest	5,614	(101)	(94)	2,376	1,739	2,809	(1,558)
72 Schedule "M" Additions	-	-	-	-	-	-	-
73 Schedule "M" Deductions	-	-	-	-	-	-	-
74 Income Before Tax	(9,616,448)	172,196	161,154	(4,070,049)	(2,978,330)	(4,811,364)	2,669,271
75							
76 State Income Taxes	(436,587)	7,818	7,316	(184,780)	(135,216)	(218,436)	121,185
77 Taxable Income	(9,179,861)	164,378	153,838	(3,885,269)	(2,843,114)	(4,592,928)	2,548,086
78							
79 Federal Income Taxes + Other	(1,927,771)	34,519	32,306	(815,906)	(597,054)	(964,515)	535,098
APPROXIMATE PRICE CHANGE	9,934,656	(178,593)	(167,142)	4,218,175	3,089,399	4,990,791	(2,768,814)

PacifiCorp
Oregon General Rate Case - December 2025
Miscellaneous General Expense & Revenue

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Revenue:							
Gain on Property Sales	421	1	367,122	SO	27.425%	100,685	
Gain on Property Sales	421	1	(300,141)	SG	26.884%	(80,690)	
Gain on Property Sales	421	1	-	OR	Situs	-	
Gain on Property Sales	421	1	(21,760)	UT	Situs	-	
			45,221			19,995	4.1.1
Commercial and Industrial	442	1	1,769,316	OR	Situs	1,769,316	4.1.2
Adjustment to Expense:							
Office Supplies and Expenses	921	1	(26,294)	SO	27.425%	(7,211)	
Office Supplies and Expenses	921	1	(7,157)	SO	27.425%	(1,963)	
Re-allocate Regulatory Commission	928	1	2,763	SG	26.884%	743	
Re-allocate Regulatory Commission	928	1	(2,763)	OR	Situs	(2,763)	
Re-allocate Regulatory Commission	928	1	644	UT	Situs	-	
Re-allocate Regulatory Commission	928	1	(644)	SO	27.425%	(176)	
Credit facility fees	921	1	1,640,425	SO	27.425%	449,894	
Blue Sky	909	1	(92,289)	CN	30.706%	(28,338)	
Blue Sky	909	1	14,959	OR	Situs	14,959	
Blue Sky	903	1	(9,820)	OR	Situs	(9,820)	
Blue Sky	929	1	(13,300)	SO	27.425%	(3,648)	
Remove system allocation	909	1	(414,936)	CN	30.706%	(127,408)	
Add situs allocation	909	1	7,006	UT	Situs	-	
Add situs allocation	909	1	2,882	ID	Situs	-	
Add situs allocation	909	1	1,571	WY	Situs	-	
Add situs allocation	909	1	-	WA	Situs	-	
Add situs allocation	909	1	53,462	CA	Situs	-	
Add situs allocation	909	1	350,015	OR	Situs	350,015	
Remove Misc. Steam Expense	506	1	(8,333)	SG	26.884%	(2,240)	
Reallocation Gen. Expense	923	1	(225,008)	WY	Situs	-	
Reallocation Gen. Expense	557	1	225,008	SG	26.884%	60,491	
Removal of prior-period entry	557	1	730,540	SG	26.884%	196,400	
			2,228,731			888,935	4.1.1
Total Adjustment			4,043,268			2,678,245	

Description of Adjustment:

This adjustment removes from results of operations certain miscellaneous expenses that should have been charged to non-regulated accounts. It also reallocates certain items such as gains and losses on property sales to reflect the appropriate allocation. In addition, it recognizes revenues from the Oregon Customer Opt-Out amortization.

PacifiCorp
Oregon General Rate Case - December 2025
Miscellaneous General Expense & Revenue
Adjustments Required

Description	FERC	Factor	Amount	
FERC 421 - (Gain)/Loss on Sale of Utility Plant				
Gain on Property Sales	421	SO	367,122	
Gain on Property Sales	421	SG	(300,141)	
Gain on Property Sales	421	OR	-	
Gain on Property Sales	421	UT	(21,760)	
			45,221	**Ref 4.1**
Non Regulated Flights				
Office Supplies and Expenses	921	SO	(26,294)	
FERC 921 - Office Supplies & Expenses				
Office Supplies and Expenses	921	SO	(7,157)	
FERC 928 - Regulatory Commission Expenses				
Re-allocate Regulatory Commission	928	SG	2,763	
Re-allocate Regulatory Commission	928	OR	(2,763)	
Re-allocate Regulatory Commission	928	UT	644	
Re-allocate Regulatory Commission	928	SO	(644)	
Credit Facility Fee Adjustment				
Credit facility fees	921	SO	1,640,425	
Informational & Instructional Advertising				
Blue Sky	909	CN	(92,289)	
Blue Sky	909	OR	14,959	
Blue Sky	903	OR	(9,820)	
Blue Sky	929	SO	(13,300)	
Remove system allocation	909	CN	(414,936)	
Add situs allocation	909	UT	7,006	
Add situs allocation	909	ID	2,882	
Add situs allocation	909	WY	1,571	
Add situs allocation	909	WA	-	
Add situs allocation	909	CA	53,462	
Add situs allocation	909	OR	350,015	
Remove Misc. Steam Expense	506	SG	(8,333)	
Reallocation Gen. Expense	923	WY	(225,008)	
Reallocation Gen. Expense	557	SG	225,008	
Removal of prior-period entry	557	SG	730,540	
TOTAL MISC GENERAL EXPENSE REMOVED			**2,228,731**	**Ref 4.1**

PacifiCorp
Oregon General Rate Case - December 2025
Miscellaneous General Expense & Revenue

Revenues that need to be included in results:

	Five-year Opt Out Amortization	Account	Factor	
Commercial & Industrial	**1,769,316**	**442**	**OR**	**Ref 4.1**

PacifiCorp
Oregon General Rate Case - December 2025
Confidential Wages & Employee Benefits

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Steam Operations	500	3	3,517,824	SG	26.884%	945,737	
Fuel Related-Non NPC	501	3	6,371	SE	26.339%	1,678	
Steam Maintenance	512	3	2,662,415	SG	26.884%	715,768	
Hydro Operations	535	3	750,158	SG-P	26.884%	201,674	
Hydro Operations	535	3	535,742	SG-U	26.884%	144,030	
Hydro Maintenance	545	3	128,063	SG-P	26.884%	34,429	
Hydro Maintenance	545	3	38,270	SG-U	26.884%	10,289	
Other Operations	548	3	635,550	SG	26.884%	170,862	
Other Operations	549	3	1,146	OR	Situs	1,146	
Other Maintenance	553	3	150,025	SG	26.884%	40,333	
Other Power Supply Expenses	557	3	1,671,938	SG	26.884%	449,486	
Other Power Supply Expenses	557	3	2,659	OR	Situs	-	
Transmission Operations	560	3	1,452,335	SG	26.884%	390,448	
Transmission Maintenance	571	3	906,632	SG	26.884%	243,740	
Distribution Operations	580	3	2,379,231	SNPD	24.998%	594,770	
Distribution Operations	580	3	1,961,661	OR	Situs	724,744	
Distribution Maintenance	593	3	498,328	SNPD	24.998%	124,574	
Distribution Maintenance	593	3	5,283,581	OR	Situs	1,792,523	
Customer Accounts	903	3	1,559,055	CN	30.706%	478,716	
Customer Accounts	903	3	563,895	OR	Situs	98,266	
Customer Services	908	3	270,803	CN	30.706%	83,152	
Customer Services	908	3	78	OTHER	0.000%	-	
Customer Services	908	3	343,830	OR	Situs	122,000	
Administrative & General	920	3	1,548,207	SO	27.425%	424,603	
Administrative & General	920	3	(2,588)	OR	Situs	(34,386)	
Administrative & General	935	3	118,432	SO	27.425%	32,481	
Administrative & General	935	3	6,376	OR	Situs	4,870	
			26,990,019			7,795,932	4.2.11

Description of Adjustment:

This adjustment recognizes wage and benefit increases that have occurred during the base period 12 months ended June 2023, or are projected to occur during the twelve month period ending December 2025 for labor charged to operation & maintenance accounts. See page 4.2.1 for more information on how this adjustment was calculated.

The unadjusted, annualized (12 months ended June 2023), and pro forma period (12 months ending December 2025) 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 2023 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 2023 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 2023 regular time, overtime, and premium pay expenses were then escalated prospectively by labor group to December 2025 (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 on a 5-year historical average, using a ratio of AIP to wages, as adopted in Settlement and approved in UE-399. Named Executive Officers (NEO's) and one-half of remaining AIP has also been removed per Commission order in general rate case UE-374.

The Annual Incentive Plan is the second step of a two-stage compensation philosophy that provides certain employees with market average compensation with a portion at risk and based on achieving annual goals. Union employees do not participate in the Company's Annual Incentive Plan; instead, they receive annual increases to their wages that are reflected in the escalation described above. described above. Bonuses are also included on a 5-year historical average.

5. Pro Forma December 2025 pension and employee benefit expenses are based on either actuarial projections or are calculated by using actual June 2023 data escalated to December 2025. These expenses can be found on page 4.2.6.

6. Payroll tax calculations can be found on page 4.2.7.

PacifiCorp
Oregon General Rate Case - December 2025
Confidential Wage & Employee Benefits

Description	Actual 12 Months Ended June 2023	Pro Forma 12 Months Ending June 2024	Adjustment	Ref.
Regular Ordinary Time	455,251,586	492,738,759	37,487,173	
Overtime	91,478,029	99,010,683	7,532,654	
Premium Pay	12,798,107	13,851,952	1,053,845	
Subtotal for Escalation	**559,527,722**	**605,601,394**	**46,073,672**	4.2.3&4
Unused Leave	6,470,860	7,003,696	532,836	4.2.5
Temporary/Contract Labor	-	-	-	
Severance Pay	(554,764)	(554,764)	-	
Other Salary/Labor Costs	5,272,725	5,272,725	-	
Joint Owner Cutbacks	(1,057,432)	(1,144,505)	(87,073)	4.2.5
Subtotal Bare Labor	**569,659,111**	**616,178,546**	**46,519,435**	
Annual Incentive Plan	30,925,083	16,693,314	(14,231,769)	4.2.5
Total Incentive	**30,925,083**	**16,693,314**	**(14,231,769)**	
Overtime Meals	1,776,519	1,776,519	-	
Bonus and Awards	2,907,073	1,859,817	(1,047,256)	4.2.5
Physical Exam	69,612	69,612	-	
Education Assistance	186,812	186,812	-	
Mining Salary/Benefit Credit	(176,072)	(176,072)	-	
Total Other Labor	**4,763,944**	**3,716,688**	**(1,047,256)**	
Subtotal Labor and Incentive	**605,348,138**	**636,588,548**	**31,240,410**	
Pensions	5,302,118	4,231,448	(1,070,670)	4.2.6
SERP Plan	-	-	-	4.2.6
Post Retirement Benefits	(454,712)	1,351,007	1,805,719	4.2.6
Post Employment Benefits	5,210,986	4,727,828	(483,158)	4.2.6
Total Pensions	**10,058,392**	**10,310,284**	**251,892**	4.2.6
Pension Administration	1,277,414	1,277,414	-	4.2.6
Medical	57,854,950	62,483,346	4,628,396	4.2.6
Dental	3,235,573	3,322,933	87,360	4.2.6
Vision	363,698	363,698	0	4.2.6
Life	872,318	944,148	71,830	4.2.6
401(k)	45,179,962	48,900,254	3,720,292	4.2.6
401(k) Administration	194	181	(14)	4.2.6
Accidental Death & Disability	28,975	31,361	2,386	4.2.6
Long-Term Disability	4,137,531	4,478,232	340,700	4.2.6
Worker's Compensation	968,705	1,048,472	79,767	4.2.6
Other Salary Overhead	646,517	646,517	-	4.2.6
Total Benefits	**114,565,838**	**123,496,556**	**8,930,719**	4.2.6
Subtotal Pensions and Benefits	**124,624,230**	**133,806,840**	**9,182,610**	4.2.6
Payroll Tax Expense	41,756,669	43,981,868	2,225,199	4.2.7
Payroll Tax Expense-Unemployment	3,213,518	3,213,518	-	
Total Payroll Taxes	**44,970,188**	**47,195,387**	**2,225,199**	
Total Labor	**774,942,556**	**817,590,775**	**42,648,219**	4.2.11
Non-Utility and Capitalized Labor	284,518,456	300,176,656	15,658,200	4.2.11
Total Utility Labor	**490,424,100**	**517,414,119**	**26,990,019**	4.2.11
			Ref. 4.2	

PacifiCorp
Oregon General Rate Case - December 2025
Escalation of Regular, Overtime, and Premium Labor
(Figures are in thousands)

Labor (12 Months Ended June 2023)

Account Desc.	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Total	
Regular Ordinary Time	35,112	37,832	37,468	35,911	38,107	37,356	37,502	36,116	42,098	36,205	41,197	40,348	455,252	**Ref. 4.2.2**
Overtime	6,798	10,411	8,436	6,325	6,239	7,833	9,307	6,319	7,655	7,003	7,419	7,734	91,478	**Ref. 4.2.2**
Premium Pay	985	1,334	1,099	896	1,012	982	1,261	880	1,095	983	1,133	1,136	12,798	**Ref. 4.2.2**
Grand Total	**42,896**	**49,577**	**47,003**	**43,133**	**45,358**	**46,171**	**48,070**	**43,315**	**50,847**	**44,191**	**49,749**	**49,218**	**559,528**	**Ref. 4.2.2**

Labor (12 Months Ended June 2023)

Group Code	Labor Group	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Total
2	Officer/Exempt	15,814	16,868	17,522	16,037	16,817	17,497	16,637	16,353	19,892	16,218	18,759	18,880	207,295
3	IBEW 125	3,722	4,481	4,111	3,656	4,154	4,354	4,251	3,893	4,189	3,750	4,403	4,365	49,330
4	IBEW 659	4,470	6,671	5,206	3,934	4,347	4,260	5,985	4,125	4,665	4,306	4,836	4,831	57,637
5	UWUA 197	211	315	202	222	225	219	372	206	220	179	216	220	2,806
8	UWUA 127	3,911	4,328	4,280	4,083	4,095	4,305	4,098	3,798	4,209	4,343	4,251	4,263	49,965
9	IBEW 57 WY	83	88	61	59	59	59	67	60	70	68	79	80	832
11	IBEW 57 PD	9,414	11,070	10,001	9,397	9,888	9,567	10,900	9,264	11,156	9,873	11,297	10,690	122,519
12	IBEW 57 PS	3,311	3,681	3,628	3,857	3,701	3,660	3,563	3,612	4,238	3,491	3,722	3,704	44,170
13	PCCC Non-Exempt	444	492	448	421	429	441	482	425	432	420	449	443	5,326
15	IBEW 57 CT	313	337	301	302	335	373	368	348	372	325	377	358	4,106
16	IBEW 77	134	134	144	121	139	153	138	137	129	130	117	131	1,608
18	Non-Exempt	1,069	1,112	1,098	1,045	1,169	1,282	1,207	1,093	1,275	1,087	1,243	1,254	13,934
Grand Total		**42,896**	**49,577**	**47,003**	**43,133**	**45,358**	**46,171**	**48,070**	**43,315**	**50,847**	**44,191**	**49,749**	**49,218**	**559,528**

Annualization Increase

Group Code	Labor Group	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	
2	Officer/Exempt							3.54%						(1)
3	IBEW 125								4.50%					(1,5)
4	IBEW 659	1.50%										2.00%		(1)
5	UWUA 197												4.50%	(1,5)
8	UWUA 127				2.25%									(1)
9	IBEW 57 WY	2.50%												(1)
11	IBEW 57 PD								4.00%					(1,6)
12	IBEW 57 PS								4.00%					(1,6)
13	PCCC Non-Exempt							2.45%						(1)
15	IBEW 57 CT								4.00%					(1,6)
16	IBEW 77								2.00%					(1)
18	Non-Exempt							3.17%						(1)

Annualized Labor June 2023

Group Code	Labor Group	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Total	
2	Officer/Exempt	16,374	17,465	18,143	16,605	17,412	18,116	16,637	16,353	19,892	16,218	18,759	18,880	210,855	
3	IBEW 125	3,889	4,683	4,296	3,820	4,341	4,550	4,443	3,893	4,189	3,750	4,403	4,365	50,622	
4	IBEW 659	4,559	6,804	5,310	4,012	4,434	4,345	6,105	4,208	4,758	4,392	4,836	4,831	58,596	
5	UWUA 197	221	329	211	232	235	229	389	215	230	187	226	220	2,923	
8	UWUA 127	3,999	4,426	4,376	4,083	4,095	4,305	4,098	3,798	4,209	4,343	4,251	4,263	50,247	
9	IBEW 57 WY	83	88	61	59	59	59	67	60	70	68	79	80	832	
11	IBEW 57 PD	9,791	11,513	10,401	9,773	10,284	9,950	11,336	9,264	11,156	9,873	11,297	10,690	125,329	
12	IBEW 57 PS	3,444	3,828	3,774	4,012	3,849	3,807	3,706	3,612	4,238	3,491	3,722	3,704	45,186	
13	PCCC Non-Exempt	455	504	458	431	439	452	482	425	432	420	449	443	5,392	
15	IBEW 57 CT	325	350	313	314	348	388	382	348	372	325	377	358	4,199	
16	IBEW 77	136	137	147	124	142	157	141	137	129	130	117	131	1,627	
18	Non-Exempt	1,103	1,147	1,133	1,078	1,206	1,322	1,207	1,093	1,275	1,087	1,243	1,254	14,149	
Grand Total		**44,379**	**51,274**	**48,624**	**44,542**	**46,844**	**47,680**	**48,994**	**43,407**	**50,951**	**44,285**	**49,759**	**49,218**	**569,956**	**Ref. 4.2.2**

(1) Overall actual.
(2) Labor increases supported by union contracts/actual increases.
(3) Projected labor increases supported by planned targets.
(4) Increase will be contingent on the future outcome of a new contract. (CONFIDENTIAL)
(5) A general increase of 2.5% and an additional adjustment of 2.0% for 2023.
(6) A general increase of 2.5% and an additional adjustment of 1.5% for 2023.
(7) A general increase of 2.5% and an additional adjustment of 2% for 2024.

PacifiCorp
Oregon General Rate Case - December 2025
Escalation of Regular, Overtime, and Premium Labor
(Figures are in thousands)

Note: Please see Confidential Exhibit PAC/1704_CONF for redacted information.

Pro Forma Increase to December 2025
Increases occur on the 26th of each month. For this exhibit, each increase is listed on the first day of the following month. For example, an increase that occurs on December 26, 2023 is shown as effective on January 1, 2024.

Group Code	Labor Group	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
2	Officer/Exempt													
	12/26/2023	3.50%												(3)
	12/26/2024	3.50%												(3)
3	IBEW 125													
	1/26/2024		2.50%											(2)
	1/26/2025		2.50%											(2)
4	IBEW 659													
	[redacted]													(4) CONF
														(4) CONF
5	UWUA 197													
	5/26/2024						2.50%							(2)
	5/26/2025						2.50%							(2)
8	UWUA 127													
	9/26/2023										2.25%			(2)
	9/26/2024										2.50%			(2)
	9/26/2025										2.50%			(2)
9	IBEW 57 WY													
	6/26/2023							4.00%						(2)
	6/26/2024							4.50%						(2)
	6/26/2025							2.50%						(2)
11	IBEW 57 PD													
	1/26/2024		4.50%											(2,7)
	1/26/2025		2.50%											(2)
12	IBEW 57 PS													
	1/26/2024		4.50%											(2,7)
	1/26/2025		2.50%											(2)
13	PCCC Non-Exempt													
	12/26/2023	3.50%												(3)
	12/26/2024	3.50%												(3)
15	IBEW 57 CT													
	1/26/2024		4.50%											(2,7)
	1/26/2025		2.50%											(2)
16	IBEW 77													
	[redacted]													(4) CONF
														(4) CONF
18	Non-Exempt													
	12/26/2023	3.50%												(3)
	12/26/2024	3.50%												(3)

Pro Forma Labor December 2025

Group Code	Labor Group	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	
2	Officer/Exempt	17,822	17,518	21,309	17,373	20,095	20,225	17,540	18,709	19,435	17,788	18,652	19,407	225,873	
3	IBEW 125	4,443	4,090	4,401	3,940	4,626	4,586	4,086	4,920	4,514	4,014	4,561	4,780	52,960	
4	IBEW 659	[redacted]													
5	UWUA 197	389	215	230	187	226	231	232	345	221	243	247	241	3,008	
8	UWUA 127	4,098	3,798	4,209	4,343	4,251	4,263	3,999	4,426	4,376	4,386	4,400	4,624	51,174	
9	IBEW 57 WY	67	60	70	68	79	80	92	98	68	66	65	66	878	
11	IBEW 57 PD	11,336	9,923	11,950	10,575	12,100	11,451	10,487	12,332	11,141	10,468	11,015	10,658	133,436	
12	IBEW 57 PS	3,706	3,869	4,540	3,739	3,987	3,968	3,689	4,101	4,042	4,297	4,122	4,077	48,137	
13	PCCC Non-Exempt	517	456	463	450	481	475	487	540	491	462	471	484	5,776	
15	IBEW 57 CT	382	373	398	348	403	383	349	375	335	336	373	416	4,471	
16	IBEW 77	[redacted]													
18	Non-Exempt	1,293	1,171	1,365	1,164	1,332	1,343	1,181	1,229	1,214	1,155	1,292	1,417	15,156	
Grand Total		**50,544**	**45,998**	**54,024**	**47,103**	**52,964**	**52,395**	**47,245**	**54,618**	**51,768**	**47,708**	**50,171**	**51,061**	**605,601**	**Ref. 4.2.2**

(1) Overall actual.
(2) Labor increases supported by union contracts/actual increases.
(3) Projected labor increases supported by planned targets.
(4) Increase will be contingent on the future outcome of a new contract. (CONFIDENTIAL)
(5) A general increase of 2.5% and an additional adjustment of 2.0% for 2023.
(6) A general increase of 2.5% and an additional adjustment of 1.5% for 2023.
(7) A general increase of 2.5% and an additional adjustment of 2% for 2024.

PacifiCorp
Oregon General Rate Case - December 2025
Confidential Wage & Employee Benefits

Composite Labor Increases

			Ref.
Regular Time/Overtime/Premium Pay - Actual	559,527,722		4.2.2
Regular Time/Overtime/Premium Pay Dec 2025 - Pro Forma	605,601,394	CAGR[1]	4.2.2
% Increase	8.23%	*3.22%*	

Miscellaneous Bare Labor Escalation

Description	June 2023 Actual	Pro Forma Increase	December 2025 Pro Forma	Pro Forma Adjustment	Ref.
Unused Leave	6,470,860	8.23%	7,003,696	532,836	4.2.2
Joint Owner Cutbacks	(1,057,432)	8.23%	(1,144,505)	(87,073)	4.2.2
	5,413,429		5,859,191	445,763	

Bonus and Awards Calculation:

Description	June 2023 Actual	Pro Forma Increase	December 2025 Pro Forma	Pro Forma Adjustment	Ref.
Bonus and Awards Calculation	2,907,073		1,859,817	**(1,047,256)**	4.2.2

Year	Exempt Bonus[3]	Non-Exempt and Union Bonus	Total	
2022	1,288,716	419,961	1,708,677	
2021	41,767	141,126	182,893	
2020	660,585	989,763	1,650,348	
2019	2,873,088	1,026,198	3,899,286	
2018	824,535	1,033,346	1,857,881	
	5,688,691	3,610,394	9,299,084	Total
	1,137,738	722,079	**1,859,817**	5-Year Avg.
			Above	

Annual Incentive Plan Escalation

Description	June 2023 Actual	December 2025	Remove 50%[2]	Pro Forma Adjustment	Ref.
Annual Incentive Plan Compensation	30,925,083	33,386,628	16,693,314	**(14,231,769)**	4.2.2

Year	Exempt Wages[3]	AIP[3]	%	
2022	193,734,722	31,894,180	16.463%	
2021	188,363,246	28,389,339	15.072%	
2020	196,651,699	27,916,645	14.196%	
2019	190,966,807	28,914,550	15.141%	
2018	183,538,498	27,045,212	14.735%	
	759,520,250	112,265,746	14.781%	Total
2025	225,873,167	**33,386,628**	14.781%	5-Year Avg.
		Above		

[1]Compound Annual Growth Rate
[2] Per Commission Order in GRC UE-374, Order No. 20-473
[3] Net of Named Executive Officers (NEO's) Compensation

PacifiCorp
Oregon General Rate Case - December 2025
Confidential Wage & Employee Benefits

	A	B	C	D	D - A	
Description	**Actual June 2023 Net of Joint Venture**	**Actual June 2023 Gross**	**Projected December 2025 Gross**	**Projected December 2025 Net of Joint Venture**	**Pro Forma Adjustment**	**Ref**
Pensions	5,302,118	5,388,015	4,300,000	4,231,448	**(1,070,670)**	4.2.2
SERP Plan	-	-	-	-	**-**	4.2.2
Post Retirement Benefits	(454,712)	(413,808)	1,229,477	1,351,007	**1,805,719**	4.2.2
Post Employment Benefits	5,210,986	5,358,850	4,861,982	4,727,828	**(483,158)**	4.2.2
Subtotal	10,058,392	10,333,057	10,391,459	10,310,284	**251,892**	4.2.2
Pension Administration	1,277,414	1,313,590	1,313,590	1,277,414	**-**	4.2.2
Medical	57,854,950	59,531,368	64,293,877	62,483,346	**4,628,396**	4.2.2
Dental	3,235,573	3,334,059	3,424,079	3,322,933	**87,360**	4.2.2
Vision	363,698	374,405	374,405	363,698	**-**	4.2.2
Life	872,318	898,188	972,148	944,148	**71,830**	4.2.2
401(k)	45,179,962	46,396,892	50,217,392	48,900,254	**3,720,292**	4.2.2
401(k) Administration	194	200	186	181	**(14)**	4.2.2
Accidental Death & Disability	28,975	29,287	31,698	31,361	**2,386**	4.2.2
Long-Term Disability	4,137,531	4,254,762	4,605,116	4,478,232	**340,700**	4.2.2
Worker's Compensation	968,705	994,528	1,076,421	1,048,472	**79,767**	4.2.2
Other Salary Overhead	646,517	647,276	647,276	646,517	**-**	4.2.2
Subtotal	114,565,838	117,774,555	126,956,188	123,496,556	**8,930,719**	4.2.2
Grand Total	**124,624,230**	128,107,612	137,347,647	**133,806,840**	**9,182,610**	4.2.2
	Ref. 4.2.2			Ref. 4.2.2	Ref. 4.2.2	

PacifiCorp
Oregon General Rate Case - December 2025
Confidential Wage & Employee Benefits
Payroll Tax Adjustment Calculation

	Line No.	Ref	Social Security	Medicare	Total FICA Tax	Ref
FICA Calculated on December 2025 Pro Forma Labor						
Pro Forma Wages Adjustment	h		45,540,837	45,540,837		4.2.2
Pro Forma Incentive Adjustment	i		(14,231,769)	(14,231,769)		4.2.2
	j	h + i	31,309,068	31,309,068		
Percentage of eligible wages	k		91.25%	100.00%		
Total eligible wages	l	j * k	28,568,022	31,309,068		
Tax rate	m		6.20%	1.45%		
Tax on eligible wages	n	l * m	1,771,217	453,981		
Total FICA Tax on Pro Forma Labor		n	**1,771,217**	**453,981**	**2,225,199**	4.2.2

PacifiCorp
Oregon General Rate Case - December 2025
Confidential Wage & Employee Benefits

2020P Indicator	Actual 12 Months Ended June 2023	% Of Total	Pro Forma Adjustment	Pro Forma 12 Months Ending December 2025	Oregon Allocation %	Pro Forma Adjustment Oregon Allocated	Pro Forma 12 Months Ending December 2023 Oregon Allocated
500SG	13,138,397	1.6954%	723,059	13,861,456	26.884%	194,388	3,726,536
502SG	19,917,201	2.5702%	1,096,124	21,013,325	26.884%	294,684	5,649,255
503SE	115,757	0.0149%	6,371	122,127	26.339%	1,678	32,167
505SG	19,411	0.0025%	1,068	20,480	26.884%	287	5,506
506SG	30,845,860	3.9804%	1,697,572	32,543,433	26.884%	456,378	8,749,028
510SG	3,853,314	0.4972%	212,063	4,065,378	26.884%	57,011	1,092,942
511SG	6,963,219	0.8985%	383,214	7,346,433	26.884%	103,024	1,975,027
512SG	24,033,010	3.1013%	1,322,634	25,355,644	26.884%	355,579	6,816,651
513SG	11,585,627	1.4950%	637,604	12,223,231	26.884%	171,414	3,286,113
514SG	1,942,432	0.2507%	106,900	2,049,332	26.884%	28,739	550,946
535SG-P	5,141,383	0.6635%	282,951	5,424,334	26.884%	76,069	1,458,287
535SG-U	4,649,575	0.6000%	255,885	4,905,460	26.884%	68,792	1,318,792
536SG-P	56,977	0.0074%	3,136	60,112	26.884%	843	16,161
537SG-P	628,804	0.0811%	34,606	663,409	26.884%	9,303	178,352
537SG-U	1,068	0.0001%	59	1,127	26.884%	16	303
539SG-P	7,803,101	1.0069%	429,436	8,232,538	26.884%	115,450	2,213,248
539SG-U	5,084,095	0.6561%	279,798	5,363,893	26.884%	75,221	1,442,037
540SG-P	533	0.0001%	29	563	26.884%	8	151
542SG-P	282,665	0.0365%	15,556	298,222	26.884%	4,182	80,174
542SG-U	11,551	0.0015%	636	12,187	26.884%	171	3,276
543SG-P	480,302	0.0620%	26,433	506,735	26.884%	7,106	136,231
543SG-U	301,138	0.0389%	16,573	317,711	26.884%	4,455	85,414
544SG-P	766,387	0.0989%	42,177	808,565	26.884%	11,339	217,376
544SG-U	258,283	0.0333%	14,214	272,497	26.884%	3,821	73,258
545SG-P	797,632	0.1029%	43,897	841,529	26.884%	11,801	226,238
545SG-U	124,422	0.0161%	6,847	131,269	26.884%	1,841	35,291
546SG	10,132	0.0013%	558	10,689	26.884%	150	2,874
548SG	6,711,092	0.8660%	369,339	7,080,431	26.884%	99,294	1,903,514
549OR	20,827	0.0027%	1,146	21,973	Situs	1,146	21,973
549SG	4,827,084	0.6229%	265,654	5,092,738	26.884%	71,419	1,369,140
552SG	924,835	0.1193%	50,897	975,733	26.884%	13,683	262,318
553SG	1,710,339	0.2207%	94,127	1,804,466	26.884%	25,305	485,115
554SG	90,857	0.0117%	5,000	95,858	26.884%	1,344	25,771
556SG	589,243	0.0760%	32,428	621,671	26.884%	8,718	167,131
557ID	48,321	0.0062%	2,659	50,980	Situs	-	-
557WYU	-	0.0000%	-	-	Situs	-	-
557SG	29,790,830	3.8443%	1,639,510	31,430,339	26.884%	440,768	8,449,782
560SG	10,542,002	1.3604%	580,169	11,122,171	26.884%	155,974	2,990,102
561SG	12,151,123	1.5680%	668,725	12,819,849	26.884%	179,781	3,446,508
562SG	2,881,532	0.3718%	158,582	3,040,114	26.884%	42,634	817,309
563SG	598,344	0.0772%	32,929	631,274	26.884%	8,853	169,713
566SG	98,805	0.0127%	5,438	104,243	26.884%	1,462	28,025
567SG	117,946	0.0152%	6,491	124,437	26.884%	1,745	33,454
568SG	1,504,197	0.1941%	82,782	1,586,980	26.884%	22,255	426,646
569SG	3,264,717	0.4213%	179,671	3,444,388	26.884%	48,303	925,995
570SG	8,333,365	1.0754%	458,619	8,791,983	26.884%	123,296	2,363,651
571SG	3,311,364	0.4273%	182,238	3,493,602	26.884%	48,993	939,225
572SG	60,383	0.0078%	3,323	63,706	26.884%	893	17,127
580CA	877,324	0.1132%	48,283	925,607	Situs	-	-
580ID	114,761	0.0148%	6,316	121,077	Situs	-	-
580OR	1,587,036	0.2048%	87,341	1,674,377	Situs	87,341	1,674,377
580SNPD	8,786,349	1.1338%	483,548	9,269,897	24.998%	120,879	2,317,327
580UT	460,929	0.0595%	25,367	486,296	Situs	-	-
580WA	93,839	0.0121%	5,164	99,003	Situs	-	-
580WYP	106,341	0.0137%	5,852	112,194	Situs	-	-
580WYU	44,062	0.0057%	2,425	46,487	Situs	-	-
581SNPD	16,368,412	2.1122%	900,820	17,269,232	24.998%	225,191	4,317,033
582CA	45,956	0.0059%	2,529	48,485	Situs	-	-
582ID	321,957	0.0415%	17,719	339,675	Situs	-	-
582OR	412,961	0.0533%	22,727	435,688	Situs	22,727	435,688
582SNPD	312	0.0000%	17	329	24.998%	4	82
582UT	1,183,781	0.1528%	65,148	1,248,929	Situs	-	-
582WA	49,793	0.0064%	2,740	52,533	Situs	-	-
582WYP	549,612	0.0709%	30,247	579,859	Situs	-	-

PacifiCorp
Oregon General Rate Case - December 2025
Confidential Wage & Employee Benefits

2020P Indicator	Actual 12 Months Ended June 2023	% Of Total	Pro Forma Adjustment	Pro Forma 12 Months Ending December 2025	Oregon Allocation %	Pro Forma Adjustment Oregon Allocated	Pro Forma 12 Months Ending December 2023 Oregon Allocated
583CA	660,299	0.0852%	36,339	696,638	Situs	-	-
583ID	528,644	0.0682%	29,093	557,738	Situs	-	-
583OR	4,443,872	0.5734%	244,564	4,688,436	Situs	244,564	4,688,436
583SNPD	-	0.0000%	-	-	24.998%	-	-
583UT	3,808,928	0.4915%	209,621	4,018,549	Situs	-	-
583WA	392,940	0.0507%	21,625	414,565	Situs	-	-
583WYP	666,350	0.0860%	36,672	703,022	Situs	-	-
583WYU	54,860	0.0071%	3,019	57,879	Situs	-	-
585SNPD	258,654	0.0334%	14,235	272,889	24.998%	3,558	68,218
586CA	88,262	0.0114%	4,857	93,119	Situs	-	-
586ID	97,880	0.0126%	5,387	103,267	Situs	-	-
586OR	1,071,113	0.1382%	58,948	1,130,061	Situs	58,948	1,130,061
586UT	469,363	0.0606%	25,831	495,193	Situs	-	-
586WA	177,683	0.0229%	9,779	187,462	Situs	-	-
586WYP	203,871	0.0263%	11,220	215,091	Situs	-	-
586WYU	39,866	0.0051%	2,194	42,060	Situs	-	-
587CA	425,351	0.0549%	23,409	448,760	Situs	-	-
587ID	878,649	0.1134%	48,356	927,004	Situs	-	-
587OR	5,554,073	0.7167%	305,663	5,859,736	Situs	305,663	5,859,736
587UT	6,099,265	0.7871%	335,667	6,434,932	Situs	-	-
587WA	1,234,354	0.1593%	67,932	1,302,286	Situs	-	-
587WYP	1,108,658	0.1431%	61,014	1,169,672	Situs	-	-
587WYU	107,599	0.0139%	5,922	113,521	Situs	-	-
588CA	1,254	0.0002%	69	1,323	Situs	-	-
588ID	139,474	0.0180%	7,676	147,150	Situs	-	-
588OR	42,476	0.0055%	2,338	44,814	Situs	2,338	44,814
588SNPD	17,818,265	2.2993%	980,611	18,798,876	24.998%	245,137	4,699,419
588UT	755,275	0.0975%	41,566	796,840	Situs	-	-
588WA	17,889	0.0023%	985	18,874	Situs	-	-
588WYP	229,390	0.0296%	12,624	242,014	Situs	-	-
588WYU	56,059	0.0072%	3,085	59,145	Situs	-	-
589CA	16,456	0.0021%	906	17,361	Situs	-	-
589ID	21,324	0.0028%	1,174	22,497	Situs	-	-
589OR	57,487	0.0074%	3,164	60,650	Situs	3,164	60,650
589UT	246,361	0.0318%	13,558	259,919	Situs	-	-
589WA	10,116	0.0013%	557	10,673	Situs	-	-
589WYP	78,308	0.0101%	4,310	82,617	Situs	-	-
589WYU	12,400	0.0016%	682	13,082	Situs	-	-
590CA	111,462	0.0144%	6,134	117,596	Situs	-	-
590ID	47,930	0.0062%	2,638	50,568	Situs	-	-
590OR	864,356	0.1115%	47,569	911,925	Situs	47,569	911,925
590SNPD	2,858,357	0.3688%	157,307	3,015,664	24.998%	39,324	753,868
590UT	824,269	0.1064%	45,363	869,632	Situs	-	-
590WA	227,088	0.0293%	12,498	239,585	Situs	-	-
590WYP	222,455	0.0287%	12,243	234,698	Situs	-	-
591SNPD	2,861	0.0004%	157	3,018	24.998%	39	755
592CA	536,484	0.0692%	29,525	566,009	Situs	-	-
592ID	477,984	0.0617%	26,305	504,289	Situs	-	-
592OR	2,412,555	0.3113%	132,773	2,545,328	Situs	132,773	2,545,328
592SNPD	2,576,256	0.3324%	141,782	2,718,038	24.998%	35,443	679,466
592UT	1,683,871	0.2173%	92,670	1,776,541	Situs	-	-
592WA	646,578	0.0834%	35,584	682,162	Situs	-	-
592WYP	808,358	0.1043%	44,487	852,845	Situs	-	-
593CA	4,739,995	0.6117%	260,861	5,000,856	Situs	-	-
593ID	3,988,515	0.5147%	219,504	4,208,020	Situs	-	-
593OR	23,671,514	3.0546%	1,302,739	24,974,253	Situs	1,302,739	24,974,253
593SNPD	2,423,289	0.3127%	133,363	2,556,652	24.998%	33,339	639,122
593UT	23,541,054	3.0378%	1,295,559	24,836,614	Situs	-	-
593WA	5,191,316	0.6699%	285,699	5,477,015	Situs	-	-
593WYP	6,158,475	0.7947%	338,926	6,497,401	Situs	-	-
593WYU	599,314	0.0773%	32,983	632,296	Situs	-	-
594CA	418,566	0.0540%	23,035	441,602	Situs	-	-
594ID	550,030	0.0710%	30,270	580,300	Situs	-	-
594OR	4,939,623	0.6374%	271,847	5,211,470	Situs	271,847	5,211,470

PacifiCorp
Oregon General Rate Case - December 2025
Confidential Wage & Employee Benefits

2020P Indicator	Actual 12 Months Ended June 2023	% Of Total	Pro Forma Adjustment	Pro Forma 12 Months Ending December 2025	Oregon Allocation %	Pro Forma Adjustment Oregon Allocated	Pro Forma 12 Months Ending December 2023 Oregon Allocated
594SNPD	7,261	0.0009%	400	7,661	24.998%	100	1,915
594UT	9,749,883	1.2581%	536,575	10,286,459	Situs	-	-
594WA	1,203,288	0.1553%	66,222	1,269,509	Situs	-	-
594WYP	596,405	0.0770%	32,823	629,228	Situs	-	-
594WYU	153,993	0.0199%	8,475	162,467	Situs	-	-
595SNPD	799,699	0.1032%	44,011	843,710	24.998%	11,002	210,914
595WYU	4,506	0.0006%	248	4,754	Situs	-	-
596CA	56,279	0.0073%	3,097	59,376	Situs	-	-
596ID	47,601	0.0061%	2,620	50,221	Situs	-	-
596OR	518,183	0.0669%	28,518	546,701	Situs	28,518	546,701
596UT	141,461	0.0183%	7,785	149,246	Situs	-	-
596WA	80,438	0.0104%	4,427	84,865	Situs	-	-
596WYP	236,581	0.0305%	13,020	249,601	Situs	-	-
596WYU	64,907	0.0084%	3,572	68,479	Situs	-	-
597CA	12,088	0.0016%	665	12,753	Situs	-	-
597ID	35,688	0.0046%	1,964	37,652	Situs	-	-
597OR	139,601	0.0180%	7,683	147,283	Situs	7,683	147,283
597SNPD	17,379	0.0022%	956	18,336	24.998%	239	4,584
597UT	213,167	0.0275%	11,731	224,898	Situs	-	-
597WA	13,560	0.0017%	746	14,306	Situs	-	-
597WYP	21,759	0.0028%	1,197	22,957	Situs	-	-
597WYU	8,778	0.0011%	483	9,261	Situs	-	-
598CA	1,932	0.0002%	106	2,039	Situs	-	-
598OR	25,328	0.0033%	1,394	26,722	Situs	1,394	26,722
598SNPD	369,804	0.0477%	20,352	390,156	24.998%	5,088	97,533
598WA	18,480	0.0024%	1,017	19,497	Situs	-	-
901CN	2,283,021	0.2946%	125,644	2,408,665	30.706%	38,580	739,593
902CA	382,017	0.0493%	21,024	403,041	Situs	-	-
902CN	566,784	0.0731%	31,192	597,976	30.706%	9,578	183,612
902ID	617,751	0.0797%	33,997	651,749	Situs	-	-
902OR	1,365,871	0.1763%	75,169	1,441,040	Situs	75,169	1,441,040
902UT	4,102,961	0.5295%	225,803	4,328,764	Situs	-	-
902WA	841,864	0.1086%	46,331	888,195	Situs	-	-
902WYP	823,128	0.1062%	45,300	868,428	Situs	-	-
902WYU	175,139	0.0226%	9,639	184,778	Situs	-	-
903CA	29,228	0.0038%	1,609	30,836	Situs	-	-
903CN	25,479,120	3.2879%	1,402,219	26,881,339	30.706%	430,559	8,254,058
903ID	113,086	0.0146%	6,224	119,310	Situs	-	-
903OR	419,687	0.0542%	23,097	442,784	Situs	23,097	442,784
903UT	1,063,088	0.1372%	58,506	1,121,594	Situs	-	-
903WA	104,223	0.0134%	5,736	109,959	Situs	-	-
903WYP	179,039	0.0231%	9,853	188,892	Situs	-	-
903WYU	29,212	0.0038%	1,608	30,819	Situs	-	-
907CN	-	0.0000%	-	-	30.706%	-	-
908CA	-	0.0000%	-	-	Situs	-	-
908CN	2,942,053	0.3796%	161,913	3,103,966	30.706%	49,716	953,089
908ID	0	0.0000%	0	0	Situs	-	-
908OR	2,216,817	0.2861%	122,000	2,338,818	Situs	122,000	2,338,818
908OTHER	1,410	0.0002%	78	1,488	0.000%	-	-
908UT	2,882,093	0.3719%	158,613	3,040,706	Situs	-	-
908WA	170,525	0.0220%	9,385	179,910	Situs	-	-
908WYP	978,159	0.1262%	53,832	1,031,991	Situs	-	-
909CN	1,978,601	0.2553%	108,890	2,087,492	30.706%	33,435	640,975
910CN	-	0.0000%	-	-	30.706%	-	-
920ID	-	0.0000%	-	-	Situs	-	-
920OR	(754,268)	-0.0973%	(41,510)	(795,778)	Situs	(41,510)	(795,778)
920SO	80,273,123	10.3586%	4,417,754	84,690,878	27.425%	1,211,590	23,226,868
920UT	-	0.0000%	-	-	Situs	-	-
920WYP	-	0.0000%	-	-	Situs	-	-
921SO	41,016	0.0053%	2,257	43,273	27.425%	619	11,868
922SO	(24,725,802)	-3.1907%	(1,360,761)	(26,086,562)	27.425%	(373,195)	(7,154,361)
928CA	59,359	0.0077%	3,267	62,626	Situs	-	-
928ID	-	0.0000%	-	-	Situs	-	-
928OR	129,446	0.0167%	7,124	136,570	Situs	7,124	136,570

PacifiCorp
Oregon General Rate Case - December 2025
Confidential Wage & Employee Benefits

2020P Indicator	Actual 12 Months Ended June 2023	% Of Total	Pro Forma Adjustment	Pro Forma 12 Months Ending December 2025	Oregon Allocation %	Pro Forma Adjustment Oregon Allocated	Pro Forma 12 Months Ending December 2023 Oregon Allocated
928SO	230,207	0.0297%	12,669	242,876	27.425%	3,475	66,610
928UT	-	0.0000%	-	-	Situs	-	-
928WA	327,207	0.0422%	18,008	345,215	Situs	-	-
928WYP	191,238	0.0247%	10,525	201,763	Situs	-	-
929SO	(27,686,737)	-3.5727%	(1,523,713)	(29,210,450)	27.425%	(417,885)	(8,011,102)
935CA	600	0.0001%	33	633	Situs	-	-
935ID	-	0.0000%	-	-	Situs	-	-
935OR	88,488	0.0114%	4,870	93,358	Situs	4,870	93,358
935SO	2,151,986	0.2777%	118,432	2,270,418	27.425%	32,481	622,673
935UT	24,434	0.0032%	1,345	25,779	Situs	-	-
935WA	158	0.0000%	9	166	Situs	-	-
935WYP	2,184	0.0003%	120	2,304	Situs	-	-
Utility Labor	**490,424,100**	**63.29%**	**26,990,019**	**517,414,119**		**7,795,932**	**149,452,486**
						Ref 4.2	
Capital/Non Utility	284,518,456	36.71%	15,658,200	300,176,656			
Total Labor	**774,942,556**	**100.00%**	**42,648,219**	**817,590,775**			
	Ref 4.2.2		**Ref 4.2.2**	**Ref 4.2.2**			

PacifiCorp
Oregon General Rate Case - December 2025
Pension Related Non-Service Expense

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Pension Non-Service Expense	926	3	(27,584,274)	SO	27.418%	(7,563,106)	4.3.1
Post-Retirement Non-Service Exp.	926	3	(643,689)	SO	27.418%	(176,488)	4.3.1
SERP Non-Service Expense	926	3	(2,771,634)	SO	27.418%	(759,931)	4.3.1
			(30,999,597)			(8,499,525)	
Pension Settlement Loss Amort.	926	3	253,985	SO	27.418%	69,638	4.3.2

Description of Adjustment:

This adjustment includes the pension and post-retirement non-service expenses at the 2025 forecast level and removing Supplemental Employee Retirement Plan expenses from the actual period.

This adjustment also adds pension settlement loss amortization expense through December 2025, 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 2025
Pension Related Non-Service Expense

Description	GL 554012 Pension Non-Service Expense Actual Twelve Months Ended June 2023	GL 554022 Post-Retirement Non-Service Expense Actual Twelve Months Ended June 2023	GL 554032 SERP Non-Service Expense Actual Twelve Months Ended June 2023	Total Actual	FERC Acct	Factor
Jul-2022	(103,907)	(178,493)	228,873	(53,528)	926	SO
Aug-2022	(103,907)	(178,493)	228,873	(53,528)	926	SO
Sep-2022	(103,907)	(178,493)	228,873	(53,528)	926	SO
Oct-2022	(103,907)	(178,493)	228,873	(53,528)	926	SO
Nov-2022	(103,907)	(178,493)	228,873	(53,528)	926	SO
Dec-2022	24,822,754	(178,493)	228,873	24,873,133	926	SO
Jan-2023	(863,290)	(435,671)	233,066	(1,065,895)	926	SO
Feb-2023	(617,216)	(435,671)	233,066	(819,821)	926	SO
Mar-2023	(617,216)	(435,671)	233,066	(819,821)	926	SO
Apr-2023	(617,216)	(435,671)	233,066	(819,821)	926	SO
May-2023	(617,216)	(435,671)	233,066	(819,821)	926	SO
Jun-2023	(617,216)	(435,671)	233,066	(819,821)	926	SO
Total Actual	**20,353,848**	**(3,684,984)**	**2,771,634**	**19,440,498**		

Description	GL 554012 Pension Non-Service Expense Forecasted Twelve Months Ending December 2025	GL 554022 Post-Retirement Non-Service Expense Forecasted Twelve Months Ending December 2025	GL 554032 SERP Non-Service Expense Forecasted Twelve Months Ending December 2025	Total Forecast	FERC Acct	Factor
Jan-2025	(602,536)	(360,723)	-	(963,258)	926	SO
Feb-2025	(602,536)	(360,723)	-	(963,258)	926	SO
Mar-2025	(602,536)	(360,723)	-	(963,258)	926	SO
Apr-2025	(602,536)	(360,723)	-	(963,258)	926	SO
May-2025	(602,536)	(360,723)	-	(963,258)	926	SO
Jun-2025	(602,536)	(360,723)	-	(963,258)	926	SO
Jul-2025	(602,536)	(360,723)	-	(963,258)	926	SO
Aug-2025	(602,536)	(360,723)	-	(963,258)	926	SO
Sep-2025	(602,536)	(360,723)	-	(963,258)	926	SO
Oct-2025	(602,536)	(360,723)	-	(963,258)	926	SO
Nov-2025	(602,536)	(360,723)	-	(963,258)	926	SO
Dec-2025	(602,536)	(360,723)	-	(963,258)	926	SO
Total Forecasted	**(7,230,426)**	**(4,328,673)**	**-**	**(11,559,100)**		
Total Incremental Change	**(27,584,274)**	**(643,689)**	**(2,771,634)**	**(30,999,597)**		
	Ref 4.3	**Ref 4.3**	**Ref 4.3**	**Ref 4.3**		

PacifiCorp
Oregon General Rate Case - December 2025
Pension Related Non-Service Expense

Description	Actual 12 Months Ended June 2023	Current Period Amortization	FERC Acct	Factor
Pension Settlement Losses:				
Aug-2022	-	65,660	926	SO
Sep-2022	-	65,660	926	SO
Oct-2022	-	65,660	926	SO
Nov-2022	-	65,660	926	SO
Dec-2022	24,926,661	65,660	926	SO
Jan-2023	(246,074)	173,903	926	SO
Feb-2023	-	173,903	926	SO
Mar-2023	-	173,903	926	SO
Apr-2023	-	173,903	926	SO
May-2023	-	173,903	926	SO
Jun-2023	-	173,903	926	SO
Total Incurred	24,324,309	1,832,856		

Description	Forecasted December 2024	Current Period Amortization (over 20 Years):	FERC Acct	Factor
Pension Settlement Losses:				
Jul-2023	-	173,903	926	SO
Aug-2023	-	173,903	926	SO
Sep-2023	-	173,903	926	SO
Oct-2023	-	173,903	926	SO
Nov-2023	-	173,903	926	SO
Dec-2023	-	173,903	926	SO
Jan-2024	-	173,903	926	SO
Feb-2024	-	173,903	926	SO
Mar-2024	-	173,903	926	SO
Apr-2024	-	173,903	926	SO
May-2024	-	173,903	926	SO
Jun-2024	-	173,903	926	SO
Jul-2024	-	173,903	926	SO
Aug-2024	-	173,903	926	SO
Sep-2024	-	173,903	926	SO
Oct-2024	-	173,903	926	SO
Nov-2024	-	173,903	926	SO
Dec-2024	-	173,903	926	SO
Total Incurred	-	3,130,261		

Description	Forecasted December 2025	Current Period Amortization (over 20 Years):	FERC Acct	Factor
Jan-2025	-	173,903	926	SO
Feb-2025	-	173,903	926	SO
Mar-2025	-	173,903	926	SO
Apr-2025	-	173,903	926	SO
May-2025	-	173,903	926	SO
Jun-2025	-	173,903	926	SO
Jul-2025	-	173,903	926	SO
Aug-2025	-	173,903	926	SO
Sep-2025	-	173,903	926	SO
Oct-2025	-	173,903	926	SO
Nov-2025	-	173,903	926	SO
Dec-2025	-	173,903	926	SO
Total Incurred	-	2,086,841		
Pro Forma Adjustment		**253,985**	**Ref 4.3**	

PacifiCorp
Oregon General Rate Case - December 2025
Remove Non-Recurring Entries

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Reversal of environmental settlement accrual	545	1	7,385,140	SG	26.884%	1,985,433	4.4.1

Description of Adjustment:

This adjustment removes the accrual reversal of environmental costs related to the Klamath Settlement on a Type 1 basis.

PacifiCorp
Oregon General Rate Case - December 2025
Remove Non-Recurring Entries

FERC Account	Account Number	Description	Amount	Alloc	REF
5459000	545500	Reversal of Klamath Settlement Obligation Expense	(7,385,140)	SG	4.4

PacifiCorp
Oregon General Rate Case - December 2025
Insurance Expense

	ACCOUNT	TYPE	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Remove Inj & Damage from Unadj Results	925	1	(411,444,632)	SO	27.425%	(112,840,607)	4.5.1
Remove Inj & Damage from Unadj Results	925	1	8,898,109	OR	Situs	8,898,109	4.5.1
Adjust Injuries & Damages to 3-year average	925	3	3,960,968	OR	Situs	3,960,968	4.5.2
Property Damage Correction	924	1	(1,218)	OR	Situs	(1,218)	
Adjust property damage expense to 10-year average							
Property Insurance - Transmission	924	3	131,962	OR	Situs	131,962	4.5.3
Property Insurance - Oregon Distribution	924	3	4,134,185	OR	Situs	4,134,185	4.5.3
Property Insurance - Non-T&D	924	3	(24,782)	OR	Situs	(24,782)	4.5.3
Property Reserve June 2023 Balance Amortization	924	3	1,046,880	OR	Situs	1,046,880	4.5.4
Remove Liability Insurance Premium	925	3	(38,272,246)	SO	27.425%	(10,496,342)	4.5.5
Adjust Property Insurance Premium	924	3	(245,091)	SO	27.425%	(67,217)	4.5.5
Adjustment to Rate Base:							
Remove Injuries & Damages Reserve	2282	3	526,198,873	SO	27.425%	144,312,492	4.5.1
Remove Injuries & Damages Reserve	2281	3	10,000,000	SO	27.425%	2,742,547	4.5.1
Remove Injuries & Damages Reserve	2282	3	9,796,535	OR	Situs	9,796,535	4.5.1
Adjustment to Tax:							
Schedule M - OR Property Reserve Amortization	SCHMAT	3	7,585,912	OR	Situs	7,585,912	
Def. Inc. Tax Expense - OR Property Reserve Amort.	41110	3	(1,865,118)	OR	Situs	(1,865,118)	
Remove ADIT associated with Inj. & Damages Reserve	190	3	(131,833,072)	SO	27.425%	(36,155,834)	
Remove ADIT associated with Inj. & Damages Reserve	190	3	(2,408,635)	OR	Situs	(2,408,635)	

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 which was approved in the last case, Docket No. UE-399. 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 which was approved in the last case, Docket No. UE-399. The property insurance premiums in the base period have been adjusted to those in the Company's most current renewal. The liability insurance premiums in the base period have been removed as the Company proposes to recover those in the separate tariff for the insurance mechanism.

PacifiCorp
Oregon General Rate Case - December 2025
Insurance Expense
Injuries and Damages in Unadjusted Results

Amount in Unadjusted Results

G/L Account	Account Title	Allocator	Amount
	Net Base Year Expense	SO	**411,444,632**
			Ref 4.5
545052	Inj/Damage Ins Prov - OR	OR	**(8,898,109)**
			Ref 4.5

Injuries & Damages Reserve

		EOP Balance Jun-23	
Net Base Year Reserve	SO	**(536,198,873)**	**Ref 4.5**
Base Year Reserve Oregon	OR	**(9,796,535)**	**Ref 4.5**

PacifiCorp
Oregon General Rate Case - December 2025
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 2021	2,929,134	-			-	-		
12 Months Ended June 2022	2,576,288				-			
12 Months Ended June 2023	72,822,577				(35,000,000)			
Average Cash	26,109,333	-	26,109,333	Below	(11,666,667)	-	(11,666,667)	Below
3 Year Average of Cash Paid for Injuries & Damages Reserve			26,109,333	Above				
3 Year Average of Cash Paid for Insurance Recovery			(11,666,667)	Above				
3 Year Normalized Average			14,442,666					
Oregon SO Allocation %			27.425%					
Oregon Allocated Annual Accrual			**3,960,968**					
			Ref 4.5					

PacifiCorp
Oregon General Rate Case - December 2025
Insurance Expense
Provision for Property Damages
10-Year Average

	Actual Losses			**Escalate to 2025**		
	System Transmission Losses	Oregon Distribution Losses	System Non-T&D Losses	End CPI-U Index	% Increase	2021
June 2013				233.504		
July 2013 - June 2014	163,517	4,472,174	2,297,475	238.343	2.07%	138.282%
July 2014 - June 2015	489,976	5,264,976	87,189	238.638	0.12%	135.474%
July 2015 - June 2016	440,896	9,217,139	1,272,026	241.018	1.00%	135.307%
July 2016 - June 2017	1,138,848	15,638,087	1,274,291	244.955	1.63%	133.971%
July 2017 - June 2018	1,087,346	2,629,908	39,747	251.989	2.87%	131.817%
July 2018 - June 2019	2,589,430	13,633,167	481,817	256.143	1.65%	128.138%
July 2019 - June 2020	976,712	8,743,858	90,409	257.797	0.65%	126.060%
July 2020 - June 2021	1,519,768	16,305,116	-	271.696	5.39%	125.251%
July 2021 - June 2022	1,812,229	13,912,653	-	296.311	9.06%	118.844%
July 2022 - June 2023	1,495,577	16,831,317	-	305.109	2.97%	108.971%
July 2023 - December 2025				322.893	5.83%	105.829%

	Actual Losses Escalated to CY 2025		
	System Transmission Losses	Oregon Distribution Losses	System Non-T&D Losses
July 2013 - June 2014	226,114	6,184,201	3,176,989
July 2014 - June 2015	663,792	7,132,689	118,119
July 2015 - June 2016	596,562	12,471,416	1,721,138
July 2016 - June 2017	1,525,722	20,950,451	1,707,177
July 2017 - June 2018	1,433,312	3,466,677	52,393
July 2018 - June 2019	3,318,041	17,469,256	617,391
July 2019 - June 2020	1,231,241	11,022,493	113,969
July 2020 - June 2021	1,903,525	20,422,328	-
July 2021 - June 2022	2,153,719	16,534,304	-
July 2022 - June 2023	1,629,747	18,341,277	-
Total in 2023 $	14,681,775	133,995,091	7,507,175
10 Year Average	1,468,178	13,399,509	750,718
Oregon Allocation Factor	SG	Situs	SG
Oregon Allocation %	26.884%	100%	26.884%
June 2023 - Oregon Allocated 10 Year Average	394,707	13,399,509	201,824
UE - 374 - Oregon Allocated 10 Year Average	245,732	8,087,431	269,375
UE - 399 - Oregon Allocated 10 Year Average	279,758	10,443,216	183,838
Amount in EOP June 2023	262,745	9,265,324	226,606
Adjustment	**131,962**	**4,134,185**	**(24,782)**
	Ref 4.5	**Ref 4.5**	**Ref 4.5**

PacifiCorp
Oregon General Rate Case - December 2025
Insurance Expense
Property Damage Reserve - Amortize the June 2021 EOP Balance Over 10 Years
Amounts from Oregon General Rate Case - December 2023
Docket No. UE 399

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	
	Amount in EOP June 2023	1,046,880	
	Adjustment	**1,046,880**	**Ref 4.5**

PacifiCorp
Oregon General Rate Case - December 2025
Insurance Expense
Adjust Base Period Property Insurance Premium to CY 2023/2024 Level
Remove Base Period Liability Insurance Premiums

	Premium Renewal 2023/2024	Included in Results 12 Months Ended Jun-23	Adjustment	
Property Insurance Premium	5,521,349	5,766,440	**(245,091)**	**Ref 4.5**
Excess Liability Insurance Premium		38,272,246	**(38,272,246)**	**Ref 4.5**

PacifiCorp
Oregon General Rate Case - December 2025
Generation Overhaul Expense

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Generation Overhaul Expense - Steam	510	1	1,991,017	SG	26.884%	535,268	4.6.1
Generation Overhaul Expense - Other	553	1	2,833,691	SG	26.884%	761,814	4.6.1
			4,824,708			1,297,082	

Description of Adjustment:

This adjustment normalizes generation overhaul expenses in the 12 months ended June 2023 using a four-year average methodology. In this adjustment, overhaul expenses from July 2019 - June 2023 are restated in constant dollars to a June 2023 level using industry specific indices and then those constant dollars are averaged. The actual overhaul costs for the 12 months ended June 2023 are subtracted from the four-year average which results in this adjustment.

PacifiCorp
Oregon General Rate Case - December 2025
Generation Overhaul Expense

FUNCTION: STEAM

Period	Overhaul Expense	Restate to Constant Dollars	Constant Dollars	
12 Months Ended Jun 2020	24,450,349	29.09%	31,562,425	
12 Months Ended Jun 2021	27,793,172	23.18%	34,234,299	
12 Months Ended Jun 2022	33,039,668	9.82%	36,285,199	
12 Months Ended Jun 2023	31,372,618	0.00%	31,372,618	
4 Year Average - Steam			33,363,635	
12 Months Ended Jun 2023 Overhaul Expense - Steam			31,372,618	**Ref. 4.6.2**
Adjustment			**1,991,017**	**Ref. 4.6**

FUNCTION: OTHER

Period	Overhaul Expense	Restate to Constant Dollars (1)	Constant Dollars	
12 Months Ended Jun 2020	10,103,281	26.60%	12,790,845	
12 Months Ended Jun 2021	2,056,960	22.06%	2,510,637	
12 Months Ended Jun 2022	6,880,068	10.18%	7,580,249	
12 Months Ended Jun 2023	3,848,989	0.00%	3,848,989	
4 Year Average			6,682,680	
12 Months Ended Jun 2023 Overhaul Expense - Other			3,848,989	**Ref. 4.6.2**
Adjustment			**2,833,691**	**Ref. 4.6**

Total Adjustment	**4,824,708**	**Ref. 4.6**

PacifiCorp
Oregon General Rate Case - December 2025
Generation Overhaul Expense

Existing Units	Yr. Ended June 2020	Yr. Ended June 2021	Yr. Ended June 2022	Yr. Ended June 2023	
Steam Production					
Blundell	42,023	1,664,859	(12,666)	124,741	
Dave Johnston	120,060	4,973,811	3,979,758	5,701,845	
Gadsby	90,772	1,026,066	129,295	466,658	
Hunter	9,739,253	242,353	8,253,973	4,892,131	
Huntington	12,579,293	20,018	97,906	7,861,547	
Jim Bridger	467,066	8,586,277	10,405,550	9,696,888	
Naughton	1,285,882	5,456,306	4,921,994	384,759	
Wyodak	-	-	4,401,453	35,984	
Cholla	-	-	-	-	
Colstrip	-	3,629,152	92,842	-	
Craig	126,000	1,350,355	135,316	1,936,066	
Hayden	-	843,976	634,248	272,000	
Subtotal - Steam	24,450,349	27,793,172	33,039,668	**31,372,618**	**Ref. 4.6.1**
Total Steam Production	24,450,349	27,793,172	33,039,668	31,372,618	
Other Production					
Hermiston	3,453,637	1,339,432	703,300	3,330,569	
Currant Creek	1,703,462	89,493	2,093,766	288,991	
Lake Side	4,849,015	414,565	748,317	(397,541)	
Gadsby Peakers	-	-	-	-	
Chehalis	97,167	213,470	3,334,685	626,971	
Total - Other Production	10,103,281	2,056,960	6,880,068	**3,848,989**	**Ref. 4.6.1**
Grand Total	34,553,631	29,850,132	39,919,736	**35,221,607**	

PacifiCorp
Oregon General Rate Case - December 2025
Generation Overhaul Expense

STEAM:	**June 2020**	**June 2021**	**June 2022**	**June 2023**
Percentage Change to Jun 2023	**29.09%**	**23.18%**	**9.82%**	**0.00%**

OTHER:	**June 2020**	**June 2021**	**June 2022**	**June 2023**
Percentage Change to Jun 2023	**26.60%**	**22.06%**	**10.18%**	**0.00%**

PacifiCorp
Oregon General Rate Case - December 2025
Revenue Sensitive Items & Uncollectible Accounts

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Uncollectible Expense	904	3	1,717,034	OR	Situs	1,717,034	4.7.1
Other Taxes	408	3	6,690,549	OR	Situs	6,690,549	4.7.1
Reg. Commission Expense	928	3	1,203,250	OR	Situs	1,203,250	4.7.1

Description of Adjustment:

This adjusts the Company's actual June 2023 uncollectible accounts expense to the December 2025 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 2025
Revenue Sensitive Items & Uncollectible Accounts

Unadjusted Revenue	1,399,023,529	
Normalized Revenue	**1,678,849,207**	
Adjustments	279,825,678	
Uncollectible Expense in Base Period	8,584,525	
Uncollectible %	0.614%	
Uncollectible Expense	**1,717,034**	**Ref. 4.7**
Franchise Tax %	2.2761%	**Ref. 4.7.2**
Resource Supplier Tax %	0.1149%	**Ref. 4.7.2**
Other Tax Expense	**6,690,549**	**Ref. 4.7**
PUC Fees %	0.4300%	
PUC Fees Expense	**1,203,250**	**Ref. 4.7**

PacifiCorp
Oregon General Rate Case - December 2025
Revenue Sensitive Items & Uncollectible Accounts

Three-Year Average Franchise Tax Rate

	Composite Rate	2023	2022	2021	
Sales to Ultimate Consumers		$ 1,531,220,849	$ 1,264,763,577	$ 1,251,099,183	**(a)**
Franchise Tax Expense		$ 34,510,600	$ 28,407,493	$ 29,131,152	**(b)**
Franchise Tax Factor (2021-2023 **Avg.- Last 3 Years**)	**2.2761%** **Ref. 4.7.1**	2.2538%	2.2461%	2.3284%	**(c) = (b)/(a)**
	1/3(d) +1/3(e) + 1/3(f)	**(d)**	**(e)**	**(f)**	

Three-Year Average ODOE (Resource Supplier Fees) Rate

	Composite Rate	2023	2022	2021	
Gross Operating Revenue Subject to Assessment		$ 1,366,806,197	$ 1,286,019,938	$ 1,272,696,438	**(a)**
Energy Resource Supplier Assessment		$ 1,640,167	$ 1,363,911	$ 1,508,684	**(b)**
Oregon Department of Energy Tax Factor (2021-2023 **Avg.- Last 3 Years**)	**0.1149%** **Ref. 4.7.1**	0.1200%	0.1061%	0.1185%	**(c) = (b)/(a)**
	1/3(d) +1/3(e) + 1/3(f)	**(d)**	**(e)**	**(f)**	

PacifiCorp
Oregon General Rate Case - December 2025
Memberships and Subscriptions

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Remove Total Memberships and Subscriptions							
	930	1	(1,986,610)	SO	27.425%	(544,837)	
	930	1	-	OR	Situs	-	
Total			(1,986,610)			(544,837)	4.8.1
Add Back 75% of National & Regional Memberships							
Various	930	1	1,359,109	SO	27.425%	372,742	
Total			1,359,109			372,742	4.8.2

Description of Adjustment:

This adjustment removes expenses in excess of Commission policy allowances as stated in the Commission order UE-94. National and regional trade organizations are recognized at 75%. Western Electricity Coordinating Council and Northern Tier Transmission Group dues 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 2025
Memberships and Subscriptions

Account	Factor	Description	Amount	
Remove Total Memberships and Subscriptions in Account 930.2				
930.2	SO	Included in Unadjusted Results	(1,986,610)	
930.2	OR	Included in Unadjusted Results	-	
			(1,986,610)	**Ref 4.8**
Allowed National and Regional Trade Memberships at 75%				
930.2	SO	Albany Area Chamber of Commerce	2,353	
930.2	SO	Albany-Millersburg Economic Development Corporation	1,500	
930.2	SO	American Clean Power	178,125	
930.2	SO	Arlington Club	5,706	
930.2	SO	ASME	228	
930.2	SO	Association of Edison Illuminating Companies	9,022	
930.2	SO	Bay Area Chamber of Commerce	1,082	
930.2	SO	Bend Chamber of Commerce	1,810	
930.2	SO	Cannon Beach Chamber of Commerce	335	
930.2	SO	CEATI International	27,400	
930.2	SO	Central Point Chamber of Commerce	500	
930.2	SO	Clatsop Economic Development Resources	5,000	
930.2	SO	Columbia River Maritime Museum	500	
930.2	SO	Corvallis Chamber of Commerce	3,500	
930.2	SO	Creswell Chamber of Commerce	250	
930.2	SO	Dallas Area Visitors Center	695	
930.2	SO	Douglas Timber Operators	600	
930.2	SO	Downtown Medford Association	180	
930.2	SO	Economic Development for Central Oregon	7,500	
930.2	SO	Edison Electric Institute	1,063,550	
930.2	SO	Energy Capital Economic Development	150	
930.2	SO	Energy Systems Integration Group	962	
930.2	SO	Enterprise	750	
930.2	SO	Greater Portland, Inc.	6,000	
930.2	SO	Intermountain Electrical Association	9,500	
930.2	SO	Klamath County Chamber of Commerce	799	
930.2	SO	Klamath County Economic Development Association	5,000	
930.2	SO	Klamath Falls Downtown Association	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	980	
930.2	SO	Lincoln City Chamber of Commerce	495	
930.2	SO	Linn-Benton Utilities Coordinating Council	125	
930.2	SO	MID-WILLAMETTE UTILITY COORDINATING COUNCIL	52	
930.2	SO	Monmouth- Independence Chamber of Commerce	1,499	
930.2	SO	Myrtle Creek-Tri City Area Chamber of Commerce	105	
930.2	SO	National Joint Utilities Notifications	11,750	
930.2	SO	North American Transmission Forum	110,390	
930.2	SO	Northwest Hydroelectric Association	1,340	
930.2	SO	Northwest Public Power Association	1,625	
930.2	SO	OR Wildfire Risk Mitigation	(700)	
930.2	SO	Oregon Association of Minority Entrepreneurs	400	
930.2	SO	Oregon Business & Industry Association	-	
930.2	SO	Oregon Business Council	36,425	
930.2	SO	Oregon Economic Development Association	5,000	
930.2	SO	Oregon Energy Fund	75	
930.2	SO	Oregon State University College of Forestry	15,000	
930.2	SO	Pacific Northwest Utilities Conference Committee	119,143	
930.2	SO	Philomath Chamber of Commerce, Philomath OR	1,150	
930.2	SO	Portland Business Alliance	4,000	
930.2	SO	Prineville Chamber of Commerce	1,240	
930.2	SO	Redmond Economic Development, Inc.	5,000	
930.2	SO	RENEWABLE ENERGY WILDLIFE INSTITUTE	5,000	
930.2	SO	Rocky Mountain Electrical League	18,000	
930.2	SO	Roseburg Area Chamber of Commerce	2,225	
930.2	SO	Rotary Club of Albina	325	
930.2	SO	Rotary Club of Grants Pass	450	
930.2	SO	Rotary Club of Roseburg	310	
930.2	SO	Seaside Chamber of Commerce	395	

PacifiCorp
Oregon General Rate Case - December 2025
Memberships and Subscriptions

Account	Factor	Description	Amount
930.2	SO	Seaside Downtown Development Association	170
930.2	SO	South Coast Development Council, Inc	5,000
930.2	SO	Southern Oregon Regional Economic Development, Inc.	2,790
930.2	SO	Stayton-Sublimity Chamber of Commerce	2,500
930.2	SO	Strategic Economic Development Corporation	2,600
930.2	SO	Sutherlin Area Chamber of Commerce	125
930.2	SO	Sweet Home Chamber of Commerce	550
930.2	SO	The Chamber of Medford/Jackson County	2,247
930.2	SO	The National Hydropower Association, Inc.	43,564
930.2	SO	Tri-County Chamber of Commerce	295
930.2	SO	Umpqua Economic Development Partnership	2,500
930.2	SO	UMS Group	42,000
930.2	SO	Utility Economic Development Association, Inc.	500
930.2	SO	Wallowa County Chamber of Commerce, Enterprise OR	150
930.2	SO	Western Energy	(40)
930.2	SO	Western Labor And Management Public Affairs Committee	2,000
930.2	SO	Western Power Trading Forum	27,100
930.2	SO	Women's Energy Network	2,100
			1,812,146

Allowed Memberships and Subscriptions - 75% of amount above **1,359,109** **Ref 4.8**

PacifiCorp
Oregon General Rate Case - December 2025
Meals & Entertainment Adjustment

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Disallowance Removal	500	1	(1,085)	SG	26.884%	(292)	
	502	1	(2,290)	SG	26.884%	(616)	
	503	1	(18)	SE	26.339%	(5)	
	506	1	(13,553)	SG	26.884%	(3,644)	
	511	1	(3,939)	SG	26.884%	(1,059)	
	512	1	(434)	SG	26.884%	(117)	
	513	1	(81)	SG	26.884%	(22)	
	514	1	(6,631)	SG	26.884%	(1,783)	
	535	1	(529)	SG-P	26.884%	(142)	
	535	1	(5,421)	SG-U	26.884%	(1,457)	
	536	1	(99)	SG-P	26.884%	(27)	
	537	1	(160)	SG-P	26.884%	(43)	
	537	1	(139)	SG-U	26.884%	(37)	
	539	1	(5,097)	SG-P	26.884%	(1,370)	
	539	1	(4,636)	SG-U	26.884%	(1,246)	
	542	1	(47)	SG-U	26.884%	(13)	
	544	1	(206)	SG-P	26.884%	(55)	
	545	1	(794)	SG-P	26.884%	(214)	
	545	1	(129)	SG-U	26.884%	(35)	
	546	1	(53)	SG	26.884%	(14)	
	548	1	(968)	SG	26.884%	(260)	
	549	1	(21,131)	SG	26.884%	(5,681)	
	552	1	(681)	SG	26.884%	(183)	
	553	1	(925)	SG	26.884%	(249)	
	554	1	(11)	SG	26.884%	(3)	
	557	1	(35,845)	SG	26.884%	(9,637)	
	560	1	(9,483)	SG	26.884%	(2,549)	
	561	1	(2,196)	SG	26.884%	(590)	
	562	1	(17)	SG	26.884%	(5)	
	563	1	(768)	SG	26.884%	(206)	
	566	1	(225)	SG	26.884%	(60)	
	568	1	(1,461)	SG	26.884%	(393)	
	569	1	(15)	SG	26.884%	(4)	
	570	1	(953)	SG	26.884%	(256)	
	571	1	(1,315)	SG	26.884%	(354)	
	572	1	(91)	SG	26.884%	(24)	
	580	1	(5,664)	OR	Situs	(5,664)	
	580	1	(40,918)	SNPD	24.998%	(10,229)	
	581	1	(1,056)	SNPD	24.998%	(264)	
	583	1	(3,153)	OR	Situs	(3,153)	
	585	1	(122)	SNPD	24.998%	(30)	
	588	1	(60)	OR	Situs	(60)	
	588	1	(6,340)	SNPD	24.998%	(1,585)	
			(178,741)			(53,630)	4.9.2

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 2025
(cont.) Meals & Entertainment Adjustment

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Disallowance Removal							
	590	1	(3,980)	OR	100.000%	(3,980)	
	590	1	(16,008)	SNPD	24.998%	(4,002)	
	592	1	(0)	OR	100.000%	(0)	
	592	1	(6,541)	SNPD	24.998%	(1,635)	
	593	1	(7,050)	OR	100.000%	(7,050)	
	593	1	(14,030)	SNPD	24.998%	(3,507)	
	594	1	(119)	OR	100.000%	(119)	
	595	1	(483)	SNPD	24.998%	(121)	
	597	1	(164)	SNPD	24.998%	(41)	
	598	1	(497)	SNPD	24.998%	(124)	
	901	1	(2,331)	CN	30.706%	(716)	
	902	1	(708)	CN	30.706%	(217)	
	902	1	(2)	OR	100.000%	(2)	
	903	1	(4,631)	CN	30.706%	(1,422)	
	903	1	(0)	OR	100.000%	(0)	
	908	1	(5,950)	CN	30.706%	(1,827)	
	908	1	(8,154)	OR	100.000%	(8,154)	
	909	1	(1,978)	CN	30.706%	(607)	
	921	1	(0)	OR	100.000%	(0)	
	921	1	(269,488)	SO	27.425%	(73,908)	
	925	1	(65)	SO	27.425%	(18)	
	929	1	138	SO	27.425%	38	
	935	1	(62)	SO	27.425%	(17)	
			(342,104)			(107,430)	4.9.2
Total Adjustment			(520,844)			(161,060)	

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 2025
Meals & Entertainment Adjustment
Summary of Adjustments

Meals and Entertainment 50% Adjustment

FERC Account	Allocation	Amount
500	SG	2,170
502	SG	4,579
503	SE	37
506	SG	27,003
511	SG	7,877
512	SG	869
513	SG	162
514	SG	13,262
535	SG-P	1,058
535	SG-U	10,842
536	SG-P	198
537	SG-P	320
537	SG-U	278
539	SG-P	10,155
539	SG-U	9,272
542	SG-U	94
544	SG-P	412
545	SG-P	1,589
545	SG-U	258
546	SG	105
548	SG	1,937
549	SG	35,956
552	SG	1,363
553	SG	1,849
554	SG	23
557	SG	68,894
560	SG	18,733
561	SG	4,391
562	SG	35
563	SG	1,535
566	SG	450
568	SG	2,908
569	SG	30
570	SG	1,905
571	SG	2,630
572	SG	181
580	OR	11,327
580	SNPD	81,440
581	SNPD	2,112
583	OR	6,306
585	SNPD	244
588	OR	120
588	SNPD	12,181
590	OR	7,961
590	SNPD	31,874
592	OR	1
592	SNPD	13,082
593	OR	14,101
593	SNPD	28,060
594	OR	237
595	SNPD	966
597	SNPD	328
598	SNPD	993

Meals and Entertainment 50% Adjustment

FERC Account	Allocation	Amount
901	CN	4,663
902	CN	1,409
902	OR	3
903	CN	9,262
903	OR	0
908	CN	11,685
908	OR	16,308
909	CN	3,957
921	OR	0
921	SO	536,434
925	SO	130
929	SO	(275)
935	SO	124
Grand Total		1,028,395

Awards 50% Adjustment

FERC Account	Allocation	Amount
506	SG	104
539	SG-P	40
549	SG	6,306
557	SG	2,796
560	SG	233
568	SG	14
580	SNPD	395
588	SNPD	500
590	SNPD	143
902	CN	7
908	CN	215
921	SO	2,542
929	SO	-
Grand Total		13,294

Meals & Entertainment	1,028,395	
Disallowance	-50%	
Removal	(514,197)	
Awards	13,294	
Disallowance	-50%	
Removal	(6,647)	
Total Disallowance	**(520,844)**	**Ref. 4.9**

PacifiCorp
Oregon General Rate Case - December 2025
O&M Escalation

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Steam Operations	500	3	72,288	SG	26.884%	19,434	
Steam Operations	500	3	(52)	SG	26.884%	(14)	
Steam Operations	501	3	1,074,003	SE	26.339%	282,883	
Steam Operations	502	3	2,825,599	SG	26.884%	759,638	
Steam Operations	503	3	(5,601)	SE	26.339%	(1,475)	
Steam Operations	505	3	33,794	SG	26.884%	9,085	
Steam Operations	506	3	(317,389)	SG	26.884%	(85,327)	
Steam Operations	506	3	232,083	SG	26.884%	62,393	
Steam Operations	507	3	(10,415)	SG	26.884%	(2,800)	
Steam Maintenance	510	3	6,221	SG	26.884%	1,673	
Steam Maintenance	510	3	3,584	SG	26.884%	963	
Steam Maintenance	511	3	49,016	SG	26.884%	13,177	
Steam Maintenance	512	3	(190,574)	SG	26.884%	(51,234)	
Steam Maintenance	512	3	194,578	SG	26.884%	52,311	
Steam Maintenance	513	3	(0)	SG	26.884%	(0)	
Steam Maintenance	513	3	78,577	SG	26.884%	21,125	
Steam Maintenance	514	3	38,881	SG	26.884%	10,453	
Hydro Operations	535	3	65,583	SG-P	26.884%	17,632	
Hydro Operations	535	3	(23,023)	SG-U	26.884%	(6,190)	
Hydro Operations	535	3	(39,160)	SG	26.884%	(10,528)	
Hydro Operations	536	3	7,615	SG-P	26.884%	2,047	
Hydro Operations	537	3	65,135	SG-P	26.884%	17,511	
Hydro Operations	537	3	6,353	SG-U	26.884%	1,708	
Hydro Operations	539	3	131,513	SG-P	26.884%	35,356	
Hydro Operations	539	3	53,681	SG-U	26.884%	14,432	
Hydro Operations	539	3	(87)	SG	26.884%	(23)	
Hydro Operations	540	3	32,826	SG-P	26.884%	8,825	
Hydro Operations	540	3	(2,490)	SG-U	26.884%	(669)	
Hydro Maintenance	541	3	(5)	SG-P	26.884%	(1)	
Hydro Maintenance	542	3	(1,323)	SG-P	26.884%	(356)	
Hydro Maintenance	542	3	(30)	SG-U	26.884%	(8)	
Hydro Maintenance	543	3	(1,322)	SG-P	26.884%	(356)	
Hydro Maintenance	543	3	(599)	SG-U	26.884%	(161)	
Hydro Maintenance	544	3	(2,017)	SG-P	26.884%	(542)	
Hydro Maintenance	544	3	(248)	SG-U	26.884%	(67)	
Hydro Maintenance	545	3	(7,361)	SG-P	26.884%	(1,979)	
Hydro Maintenance	545	3	(2,334)	SG-U	26.884%	(627)	
Hydro Maintenance	545	3	(0)	SG	26.884%	(0)	
Other Operations	546	3	21,608	SG	26.884%	5,809	
Other Operations	546	3	(2)	SG	26.884%	(1)	
Other Operations	548	3	(42)	SG	26.884%	(11)	
			4,388,861			1,174,085	

Description of Adjustment:

This adjustment calculates the non-labor O&M escalation from June 2023 to December 2025 for accounts 500 to 935 , excluding NPC and property and liability insurance, using industry specific escalation indices. Before escalation indices were applied, June 2023 actual data was separated into labor and non-labor components and costs that should not be included in June 2023 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 2025
(cont.) O&M Escalation

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Other Operations	548	3	721,326	SG	26.884%	193,922	
Other Operations	548	3	17,530	SG	26.884%	4,713	
Other Operations	549	3	522	OR	Situs	522	
Other Operations	549	3	(2,884)	SG	26.884%	(775)	
Other Operations	549	3	(1,042)	SG	26.884%	(280)	
Other Operations	549	3	257,729	SG-W	26.884%	69,288	
Other Operations	550	3	16,357	OR	Situs	16,357	
Other Operations	550	3	1,742	SG	26.884%	468	
Other Operations	550	3	464,856	SG-W	26.884%	124,973	
Other Maintenance	552	3	(16)	SG	26.884%	(4)	
Other Maintenance	552	3	36,049	SG	26.884%	9,692	
Other Maintenance	552	3	1,734	SG	26.884%	466	
Other Maintenance	553	3	41,016	SG	26.884%	11,027	
Other Maintenance	553	3	427,931	SG-W	26.884%	115,046	
Other Maintenance	553	3	46,353	SG	26.884%	12,462	
Other Maintenance	553	3	5,400	SG	26.884%	1,452	
Other Maintenance	554	3	(0)	SG	26.884%	(0)	
Other Maintenance	554	3	42,193	SG-W	26.884%	11,343	
Other Maintenance	554	3	51,589	SG	26.884%	13,869	
Other Maintenance	554	3	1,860	SG	26.884%	500	
Other Operations	556	3	83,756	SG	26.884%	22,517	
Other Operations	557	3	499,125	OR	Situs	340,179	
Other Operations	557	3	199,646	SG	26.884%	53,673	
Other Operations	557	3	269	SE	26.339%	71	
Transmission Operations	560	3	(7)	SG	26.884%	(2)	
Transmission Operations	560	3	266	SG	26.884%	72	
Transmission Operations	561	3	4,567	SG	26.884%	1,228	
Transmission Operations	561	3	(2)	SG	26.884%	(0)	
Transmission Operations	562	3	(0)	SG	26.884%	(0)	
Transmission Operations	562	3	1,246	SG	26.884%	335	
Transmission Operations	563	3	(1)	SG	26.884%	(0)	
Transmission Operations	563	3	810	SG	26.884%	218	
Transmission Operations	566	3	2,663	SG	26.884%	716	
Transmission Operations	566	3	(0)	SG	26.884%	(0)	
Transmission Operations	567	3	1,546	SG	26.884%	416	
Transmission Maintenance	568	3	48	SG	26.884%	13	
Transmission Maintenance	568	3	7,107	SG	26.884%	1,911	
Transmission Maintenance	569	3	0	SG	26.884%	0	
			2,931,286			1,006,385	

Description of Adjustment:

This adjustment calculates the non-labor O&M escalation from June 2023 to December 2025 for accounts 500 to 935 , excluding NPC and property and liability insurance, using industry specific escalation indices. Before escalation indices were applied, June 2023 actual data was separated into labor and non-labor components and costs that should not be included in June 2023 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 2025
(cont.) O&M Escalation

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Transmission Maintenance	569	3	(96,986)	SG	26.884%	(26,074)	
Transmission Maintenance	570	3	(187,477)	SG	26.884%	(50,402)	
Transmission Maintenance	570	3	31	SG	26.884%	8	
Transmission Maintenance	571	3	(409,801)	SG	26.884%	(110,172)	
Transmission Maintenance	571	3	299,535	SG	26.884%	80,527	
Transmission Maintenance	572	3	3	SG	26.884%	1	
Transmission Maintenance	572	3	(3,438)	SG	26.884%	(924)	
Transmission Maintenance	573	3	(3,219)	SG	26.884%	(865)	
Distribution Operations	580	3	4,727	OR	Situs	(3,969)	
Distribution Operations	580	3	123,300	SNPD	24.998%	30,823	
Distribution Operations	581	3	(2,048)	SNPD	24.998%	(512)	
Distribution Operations	582	3	56,429	OR	Situs	14,607	
Distribution Operations	582	3	4	SNPD	24.998%	1	
Distribution Operations	583	3	11,372	OR	Situs	(41,714)	
Distribution Operations	585	3	576	SNPD	24.998%	144	
Distribution Operations	586	3	11,780	OR	Situs	5,374	
Distribution Operations	587	3	119,920	OR	Situs	35,512	
Distribution Operations	588	3	14,888	OR	Situs	(7,113)	
Distribution Operations	588	3	(376,057)	SNPD	24.998%	(94,008)	
Distribution Operations	589	3	51,351	OR	Situs	37,687	
Distribution Operations	589	3	8,427	SNPD	24.998%	2,107	
Distribution Maintenance	590	3	334,387	OR	Situs	(5,374)	
Distribution Maintenance	590	3	(15,181)	SNPD	24.998%	(3,795)	
Distribution Maintenance	591	3	(91,139)	OR	Situs	(30,417)	
Distribution Maintenance	591	3	(3,560)	SNPD	24.998%	(890)	
Distribution Maintenance	592	3	(112,493)	OR	Situs	(38,027)	
Distribution Maintenance	592	3	71,773	SNPD	24.998%	17,942	
Distribution Maintenance	593	3	(419,407)	OR	Situs	1,000,356	
Distribution Maintenance	593	3	(37,596)	SNPD	24.998%	(9,398)	
Distribution Maintenance	594	3	(1,003,073)	OR	Situs	(195,487)	
Distribution Maintenance	594	3	(94)	SNPD	24.998%	(23)	
Distribution Maintenance	595	3	199	OR	Situs	-	
Distribution Maintenance	595	3	(11,320)	SNPD	24.998%	(2,830)	
Distribution Maintenance	596	3	(53,202)	OR	Situs	(11,247)	
Distribution Maintenance	597	3	(6,409)	OR	Situs	(1,441)	
Distribution Maintenance	597	3	2,043	SNPD	24.998%	511	
Distribution Maintenance	598	3	(93,488)	OR	Situs	(29,566)	
Distribution Maintenance	598	3	(142,480)	SNPD	24.998%	(35,618)	
Customer Accounts Operations	901	3	12	OR	Situs	-	
			(1,957,712)			525,733	

Description of Adjustment:

This adjustment calculates the non-labor O&M escalation from June 2023 to December 2025 for accounts 500 to 935 , excluding NPC and property and liability insurance, using industry specific escalation indices. Before escalation indices were applied, June 2023 actual data was separated into labor and non-labor components and costs that should not be included in June 2023 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 2025
(cont.) O&M Escalation

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Customer Accounts Operations	901	3	17,608	CN	30.706%	5,406	
Customer Accounts Operations	902	3	72,524	OR	Situs	16,078	
Customer Accounts Operations	902	3	4,121	CN	30.706%	1,265	
Customer Accounts Operations	903	3	27,206	OR	Situs	4,141	
Customer Accounts Operations	903	3	339,653	CN	30.706%	104,292	
Customer Accounts Operations	904	3	628,327	OR	Situs	216,916	
Customer Accounts Operations	904	3	(23,150)	CN	30.706%	(7,108)	
Customer Accounts Operations	905	3	6	OR	Situs	(0)	
Customer Accounts Operations	905	3	4	CN	30.706%	1	
Customer Service Operations	907	3	(11)	CN	30.706%	(3)	
Customer Service Operations	908	3	(7,616)	OR	Situs	(1,241)	
Customer Service Operations	908	3	(2,331)	CN	30.706%	(716)	
Customer Service Operations	908	3	(1,239,877)	OTHER	0.000%	-	
Customer Service Operations	909	3	(21,508)	OR	Situs	(7,141)	
Customer Service Operations	909	3	(9,456)	CN	30.706%	(2,903)	
Customer Service Operations	910	3	(78)	CN	30.706%	(24)	
A&G Operations	920	3	46,443	OR	Situs	46,439	
A&G Operations	920	3	44,122	SO	27.425%	12,101	
A&G Operations	921	3	1,912	CN	30.706%	587	
A&G Operations	921	3	7,830	OR	Situs	(66)	
A&G Operations	921	3	265,306	SO	27.425%	72,761	
A&G Operations	922	3	(1,309,297)	SO	27.425%	(359,081)	
A&G Operations	923	3	167,212	OR	Situs	48,050	
A&G Operations	923	3	2,896,718	SO	27.425%	794,438	
A&G Operations	928	3	125,499	SG	26.884%	33,739	
A&G Operations	928	3	28,712	SO	27.425%	7,875	
A&G Operations	928	3	363,730	OR	Situs	130,823	
A&G Operations	929	3	942,388	SO	27.425%	258,454	
A&G Operations	930	3	71,958	OR	Situs	78,966	
A&G Operations	930	3	(122,357)	SO	27.425%	(33,557)	
A&G Operations	931	3	27,072	OR	Situs	21,016	
A&G Operations	931	3	(272,614)	SO	27.425%	(74,766)	
A&G Operations	935	3	(371)	OR	Situs	(133)	
A&G Operations	935	3	(24)	CN	30.706%	(8)	
A&G Operations	935	3	(18,720)	SO	27.425%	(5,134)	
			3,050,940			1,361,470	
			4,388,861			1,174,085	4.10
			2,931,286			1,006,385	4.10.1
			(1,957,712)			525,733	4.10.2
			3,050,940			1,361,470	4.10.3
Total Adjustment			8,413,375			4,067,673	

Description of Adjustment:

This adjustment calculates the non-labor O&M escalation from June 2023 to December 2025 for accounts 500 to 935 , excluding NPC and property and liability insurance, using industry specific escalation indices. Before escalation indices were applied, June 2023 actual data was separated into labor and non-labor components and costs that should not be included in June 2023 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 2025
O&M Escalation
12 Months Ending December 2025

Function	Allocation Code	Unadjusted O&M	4.1 Miscellaneous General Expense & Revenue	4.2 Remove Unadjusted Wages & Employee Benefits	4.4 Remove Non-Recurring Entries	4.5 Insurance Expense	4.6 Generation Overhaul Expense	4.8 Membership & Subscriptions	4.9 Meals and Entertainment Adjustment	4.11 Wildfire & Veg Management O&M	4.13 Incremental O&M
Steam Operation											
	NPCID	87,693	-	-	-	-	-	-	-	-	-
	NPCSE	612,767,769	-	-	-	-	-	-	-	-	-
	NPCSSECH	-	-	-	-	-	-	-	-	-	-
	NPCWYP	253,319	-	-	-	-	-	-	-	-	-
	SE	22,201,079	-	(115,757)	-	-	-	-	(18)	-	-
	SG	92,961,108	(8,333)	(33,055,598)	-	-	-	-	(15,843)	-	-
	SNPPS	36,145,995	-	(30,865,272)	-	-	-	-	-	-	-
	SSECH	-	-	-	-	-	-	-	-	-	-
	SSGCH	-	-	-	-	-	-	-	(1,085)	-	-
	CA	-	-	-	-	-	-	-	-	-	-
	ID	-	-	-	-	-	-	-	-	-	-
	OR	-	-	-	-	-	-	-	-	-	-
	WA	-	-	-	-	-	-	-	-	-	-
	WYP	-	-	-	-	-	-	-	-	-	-
	Steam Operation Total	764,416,963	(8,333)	(64,036,626)	-	-	-	-	(16,947)	-	-
Steam Maintenance											
	SG	37,046,165	-	(8,905,651)	-	-	1,991,017	-	(11,085)	-	(60,990,000)
	SNPPS	128,038,140	-	(39,471,951)	-	-	-	-	-	-	-
	SSGCH	-	-	-	-	-	-	-	-	-	-
	Steam Maintenance Total	165,084,305	-	(48,377,602)	-	-	1,991,017	-	(11,085)	-	(60,990,000)
Hydro Operations											
	SG-P	30,238,570	-	(13,630,799)	-	-	-	-	(5,886)	-	(402,900)
	SG-U	11,587,864	-	(9,734,738)	-	-	-	-	(5,560)	-	-
	SG	-	-	-	-	-	-	-	(4,636)	-	-
	Hydro Operations Total	41,826,434	-	(23,365,536)	-	-	-	-	(16,082)	-	(402,900)
Hydro Maintenance											
	SG-P	6,426,681	-	(2,326,987)	-	-	-	-	(1,001)	-	-
	SG-U	1,789,755	-	(695,394)	-	-	-	-	(176)	-	-
	SG	(7,385,140)	-	-	7,385,140	-	-	-	-	-	-
	Hydro Maintenance Total	831,296	-	(3,022,381)	7,385,140	-	-	-	(1,177)	-	-
Purchased Power											
	NPCSE	20,074,007	-	-	-	-	-	-	-	-	-
	NPCSG	1,207,781,184	-	-	-	-	-	-	-	-	-
	NPCCA	2,514	-	-	-	-	-	-	-	-	-
	NPCOR	80,131	-	-	-	-	-	-	-	-	-
	NPCUT	13,361,355	-	-	-	-	-	-	-	-	-
	OTHER	(519,795,484)	-	-	-	-	-	-	-	-	-
	Purchase Power Total	721,503,708	-	-	-	-	-	-	-	-	-
Other Operations											
	NPCSE	621,099,417	-	-	-	-	-	-	-	-	-
	NPCSSECT	628,119	-	-	-	-	-	-	-	-	-
	SG-W	17,220,851	-	(682,124)	-	-	-	-	-	-	-
	SNPPO	27,406,981	-	(10,386,504)	-	-	-	-	-	-	-
	SSGCT	880,908	-	(479,680)	-	-	-	-	-	-	-
	SE	6,158	-	-	-	-	-	-	-	-	-
	SG	35,946,961	955,548	(30,380,073)	-	-	-	-	(57,997)	-	-
	ID	3,589,393	-	(48,321)	-	-	-	-	-	-	-
	OR	8,193,280	-	(20,827)	-	-	-	-	-	-	-
	UT	35,000	-	-	-	-	-	-	-	-	-
	WYU	61,932	-	-	-	-	-	-	-	-	-
	Other Operations Total	715,068,999	955,548	(41,997,529)	-	-	-	-	(57,997)	-	-
Other Maintenance											
	SNPPO	7,916,295	-	(2,296,896)	-	-	-	-	-	-	-
	SSGCT	539,246	-	(162,056)	-	-	-	-	-	-	-
	SG	-	-	-	-	-	2,833,691	-	(1,618)	-	-
	SG-W	19,983,385	-	(267,080)	-	-	-	-	-	-	-
	Other Maintenance Total	28,438,926	-	(2,726,031)	-	-	2,833,691	-	(1,618)	-	-
Transmission Operations											
	NPCSE	25,912,615	-	-	-	-	-	-	-	-	-
	NPCSG	141,048,505	-	-	-	-	-	-	-	-	-
	SG	-	-	-	-	-	-	-	(12,689)	-	-
	SNPT	42,554,838	-	(26,389,753)	-	-	-	-	-	-	-
	Transmission Operations Total	209,515,958	-	(26,389,753)	-	-	-	-	(12,689)	-	-
Transmission Maintenance											
	SNPT	37,660,999	-	(16,474,026)	-	-	-	-	-	-	-
	SG	-	-	-	-	-	-	-	(3,834)	(9,145,557)	-
	Transmission Maintenance Total	37,660,999	-	(16,474,026)	-	-	-	-	(3,834)	(9,145,557)	-

PacifiCorp
Oregon General Rate Case - December 2025
O&M Escalation
12 Months Ending December 2025

Function	Allocation Code	Unadjusted O&M	4.1 Miscellaneous General Expense & Revenue	4.2 Remove Unadjusted Wages & Employee Benefits	4.4 Remove Non-Recurring Entries	4.5 Insurance Expense	4.6 Generation Overhaul Expense	4.8 Membership & Subscriptions	4.9 Meals and Entertainment Adjustment	4.11 Wildfire & Veg Management O&M	4.13 Incremental O&M
Distribution Operations											
	CA	2,057,158	-	(2,114,902)	-	-	-	-	-	-	-
	ID	2,935,411	-	(2,102,689)	-	-	-	-	-	-	-
	OR	15,077,850	-	(13,169,018)	-	-	-	-	(8,876)	-	-
	SNPD	31,716,436	-	(43,231,991)	-	-	-	-	(48,436)	-	-
	UT	20,645,775	-	(13,023,901)	-	-	-	-	-	-	-
	WA	2,517,728	-	(1,976,615)	-	-	-	-	-	-	-
	WYP	4,772,316	-	(2,942,530)	-	-	-	-	-	-	-
	WYU	371,755	-	(314,845)	-	-	-	-	-	-	-
Distribution Operations Total		80,094,429	-	(78,876,492)	-	-	-	-	(57,313)	-	-
Distribution Maintenance											
	CA	20,470,244	-	(5,876,807)	-	-	-	-	-	-	-
	ID	6,834,223	-	(5,147,749)	-	-	-	-	-	-	-
	OR	78,536,105	-	(32,571,160)	-	-	-	-	(11,150)	(61,564,703)	-
	SNPD	12,184,335	-	(9,054,907)	-	-	-	-	(37,723)	-	-
	UT	60,452,695	-	(36,153,705)	-	-	-	-	-	-	-
	WA	10,788,723	-	(7,380,747)	-	-	-	-	-	-	-
	WYP	11,165,325	-	(8,044,034)	-	-	-	-	-	-	-
	WYU	2,075,313	-	(831,497)	-	-	-	-	-	-	-
Distribution Maintenance Total		202,506,962	-	(105,060,605)	-	-	-	-	(48,872)	(61,564,703)	-
Customer Accounts Operations											
	CA	1,274,095	-	(411,245)	-	-	-	-	-	-	-
	CN	41,722,304	-	(28,328,925)	-	-	-	-	(7,670)	-	-
	ID	1,507,505	-	(730,838)	-	-	-	-	-	-	-
	OR	11,180,100	(9,820)	(1,785,558)	-	-	-	-	(2)	-	-
	UT	13,249,652	-	(5,166,049)	-	-	-	-	-	-	-
	WA	8,712,775	-	(946,087)	-	-	-	-	-	-	-
	WYP	2,870,088	-	(1,002,167)	-	-	-	-	-	-	-
	WYU	275,681	-	(204,351)	-	-	-	-	-	-	-
Customer Accounts Operations Total		80,792,201	(9,820)	(38,575,220)	-	-	-	-	(7,672)	-	-
Customer Service Operations											
	CA	48,063	53,462	-	-	-	-	-	-	-	-
	CN	6,805,379	(507,225)	(4,920,654)	-	-	-	-	(7,928)	-	-
	ID	204,339	2,882	(0)	-	-	-	-	-	-	-
	OR	2,826,705	364,974	(2,216,817)	-	-	-	-	(8,154)	-	-
	OTHER	142,989,906	-	(1,410)	-	-	-	-	-	-	-
	UT	4,375,880	7,006	(2,882,093)	-	-	-	-	-	-	-
	WA	456,466	-	(170,525)	-	-	-	-	-	-	-
	WYP	1,273,133	1,571	(978,159)	-	-	-	-	-	-	-
	WYU	-	-	-	-	-	-	-	-	-	-
Customer Service Operations Total		158,979,871	(77,330)	(11,169,659)	-	-	-	-	(16,082)	-	-
A&G Operations & Maintenance											
	920	80,456,405	-	(79,518,855)	-	-	-	-	-	-	-
	921	17,550,657	1,606,974	(41,016)	-	-	-	-	(269,488)	-	-
	922	(48,437,529)	-	24,725,802	-	-	-	-	-	-	-
	923	52,372,720	(225,008)	-	-	-	-	-	-	-	-
	924	19,551,510	-	-	-	(1,218)	-	-	-	-	-
	925	456,920,112	-	-	-	(402,546,523)	-	-	(65)	-	-
	926	5,622,520	-	-	-	-	-	-	-	-	-
	928	27,288,977	-	(937,458)	-	-	-	-	-	-	-
	929	(10,325,949)	(13,300)	27,686,737	-	-	-	-	138	-	-
	930	2,839,086	-	-	-	-	-	(627,501)	-	-	-
	931	(3,678,774)	-	-	-	-	-	-	-	-	-
	935	30,271,987	-	(2,267,849)	-	-	-	-	(62)	-	-
A&G Operations & Maintenance Total		630,431,721	1,368,666	(30,352,639)	-	(402,547,741)	-	(627,501)	(269,478)	-	-
	Grand Total	3,837,152,773	2,228,731	(490,424,100)	7,385,140	(402,547,741)	4,824,708	(627,501)	(520,844)	(70,710,260)	(61,392,900)

PacifiCorp
Oregon General Rate Case - December 2025
O&M Escalation
12 Months Ending December 2025

Function	Allocation Code	5.1 NPC Adjustment	8.9 Remove Rolling Hills	8.10 Deer Creek Mine Adjustment	8.11 Emissions Control Investment Adjustment	8.13 Cholla Unit 4 Retirement	8.20 Klamath Regulatory Asset	O&M Before Escalation	Escalation Percentages	4.10 O&M Expense Escalation	O&M After Escalation
Steam Operation											
	NPCID	-	-	-	-	-	-	87,693	0.00%	-	87,693
	NPCSE	-	-	-	-	-	-	612,767,769	0.00%	-	612,767,769
	NPCSSECH	-	-	-	-	-	-	-	0.00%	-	0
	NPCWYP	-	-	-	-	-	-	253,319	0.00%	-	253,319
	SE	-	-	-	-	-	-	22,085,304	4.84%	1,068,402	23,153,705
	SG	-	-	(6,538,963)	-	-	-	53,342,370	4.84%	2,580,498	55,922,869
	SNPPS	-	-	-	-	-	-	5,280,723	4.84%	255,461	5,536,184
	SSECH	-	-	-	-	-	-	-	4.84%	-	0
	SSGCH	-	-	-	-	-	-	(1,085)	4.84%	(52)	(1,138)
	CA	-	-	-	-	-	-	-	4.84%	-	0
	ID	-	-	-	-	-	-	-	4.84%	-	0
	OR	-	-	-	-	-	-	-	4.84%	-	0
	WA	-	-	-	-	-	-	-	4.84%	-	0
	WYP	-	-	-	-	-	-	-	4.84%	-	0
	Steam Operation Total	-	-	(6,538,963)	-	-	-	693,816,094		3,904,309	697,720,403
Steam Maintenance											
	SG	-	-	-	-	-	-	(30,869,553)	0.31%	(96,457)	(30,966,010)
	SNPPS	-	-	-	-	-	-	88,566,189	0.31%	276,738	88,842,927
	SSGCH	-	-	-	-	-	-	-	0.31%	-	0
	Steam Maintenance Total	-	-	-	-	-	-	57,696,636		180,282	57,876,917
Hydro Operations											
	SG-P	-	-	-	-	-	-	16,198,985	1.87%	302,672	16,501,657
	SG-U	-	-	-	-	-	-	1,847,566	1.87%	34,521	1,882,087
	SG	-	-	-	-	-	(2,095,842)	(2,100,477)	1.87%	(39,247)	(2,139,724)
	Hydro Operations Total	-	-	-	-	-	(2,095,842)	15,946,074		297,946	16,244,020
Hydro Maintenance											
	SG-P	-	-	-	-	-	-	4,098,693	-0.29%	(12,028)	4,086,665
	SG-U	-	-	-	-	-	-	1,094,185	-0.29%	(3,211)	1,090,974
	SG	-	-	-	-	-	-	0	-0.29%	(0)	0
	Hydro Maintenance Total	-	-	-	-	-	-	5,192,878		(15,239)	5,177,639
Purchased Power											
	NPCSE	-	-	-	-	-	-	20,074,007	0.00%	-	20,074,007
	NPCSG	(77,418,726)	-	-	-	-	-	1,130,362,458	0.00%	-	1,130,362,458
	NPCCA	-	-	-	-	-	-	2,514	0.00%	-	2,514
	NPCOR	-	-	-	-	-	-	80,131	0.00%	-	80,131
	NPCUT	-	-	-	-	-	-	13,361,355	0.00%	-	13,361,355
	OTHER	-	-	-	-	-	-	(519,795,484)	0.00%	-	(519,795,484)
	Purchase Power Total	(77,418,726)	-	-	-	-	-	644,084,982		-	644,084,982
Other Operations											
	NPCSE	-	-	-	-	-	-	621,099,417	0.00%	-	621,099,417
	NPCSSECT	-	-	-	-	-	-	628,119	0.00%	-	628,119
	SG-W	-	-	-	-	-	-	16,538,727	4.37%	722,585	17,261,312
	SNPPO	-	-	-	-	-	-	17,020,477	4.37%	743,633	17,764,110
	SSGCT	-	-	-	-	-	-	401,228	4.37%	17,530	418,758
	SE	-	-	-	-	-	-	6,158	4.37%	269	6,427
	SG	-	(44,874)	-	-	-	-	6,419,565	4.37%	280,474	6,700,039
	ID	-	-	-	-	-	-	3,541,071	4.37%	154,711	3,695,783
	OR	-	-	-	-	-	-	8,172,452	4.37%	357,059	8,529,511
	UT	-	-	-	-	-	-	35,000	4.37%	1,529	36,529
	WYU	-	-	-	-	-	-	61,932	4.37%	2,706	64,638
	Other Operations Total	-	(44,874)	-	-	-	-	673,924,147		2,280,496	676,204,643
Other Maintenance											
	SNPPO	-	-	-	-	-	-	5,619,400	2.38%	133,991	5,753,391
	SSGCT	-	-	-	-	-	-	377,190	2.38%	8,994	386,184
	SG	-	(1,112,621)	-	-	-	-	1,719,452	2.38%	40,999	1,760,451
	SG-W	-	-	-	-	-	-	19,716,305	2.38%	470,124	20,186,429
	Other Maintenance Total	-	(1,112,621)	-	-	-	-	27,432,346		654,108	28,086,454
Transmission Operations											
	NPCSE	-	-	-	-	-	-	25,912,615	0.00%	-	25,912,615
	NPCSG	-	-	-	-	-	-	141,048,505	0.00%	-	141,048,505
	SG	-	-	-	-	-	-	(12,689)	0.07%	(9)	(12,697)
	SNPT	-	-	-	-	-	-	16,165,086	0.07%	11,098	16,176,184
	Transmission Operations Total	-	-	-	-	-	-	183,113,517		11,089	183,124,606
Transmission Maintenance											
	SNPT	-	-	-	-	-	-	21,186,973	-3.27%	(693,815)	20,493,158
	SG	-	-	-	-	-	-	(9,149,392)	-3.27%	299,617	(8,849,775)
	Transmission Maintenance Total	-	-	-	-	-	-	12,037,581		(394,197)	11,643,384

PacifiCorp
Oregon General Rate Case - December 2025
O&M Escalation
12 Months Ending December 2025

Function	Allocation Code	5.1 NPC Adjustment	8.9 Remove Rolling Hills	8.10 Deer Creek Mine Adjustment	8.11 Emissions Control Investment Adjustment	8.13 Cholla Unit 4 Retirement	8.20 Klamath Regulatory Asset	O&M Before Escalation	Escalation Percentages	4.10 O&M Expense Escalation	O&M After Escalation
Distribution Operations											
	CA	-	-	-	-	-	-	(57,744)	2.13%	(1,227)	(58,971)
	ID	-	-	-	-	-	-	832,722	2.13%	17,700	850,422
	OR	-	-	-	-	-	-	1,899,955	2.13%	40,384	1,940,339
	SNPD	-	-	-	-	-	-	(11,563,991)	2.13%	(245,797)	(11,809,788)
	UT	-	-	-	-	-	-	7,621,874	2.13%	162,006	7,783,880
	WA	-	-	-	-	-	-	541,113	2.13%	11,502	552,614
	WYP	-	-	-	-	-	-	1,829,786	2.13%	38,893	1,868,679
	WYU	-	-	-	-	-	-	56,909	2.13%	1,210	58,119
Distribution Operations Total		-	-	-	-	-	-	1,160,624		24,670	1,185,294
Distribution Maintenance											
	CA	-	-	-	-	-	-	14,593,437	-4.41%	(643,902)	13,949,535
	ID	-	-	-	-	-	-	1,686,474	-4.41%	(74,412)	1,612,062
	OR	-	-	-	-	-	-	(15,610,908)	-4.41%	688,796	(14,922,112)
	SNPD	-	-	-	-	-	-	3,091,706	-4.41%	(136,415)	2,955,292
	UT	-	-	-	-	-	-	24,298,990	-4.41%	(1,072,138)	23,226,852
	WA	-	-	-	-	-	-	3,407,976	-4.41%	(150,369)	3,257,607
	WYP	-	-	-	-	-	-	3,121,291	-4.41%	(137,720)	2,983,571
	WYU	-	-	-	-	-	-	1,243,816	-4.41%	(54,881)	1,188,935
Distribution Maintenance Total		-	-	-	-	-	-	35,832,782		(1,581,041)	34,251,742
Customer Accounts Operations											
	CA	-	-	-	-	-	-	862,850	2.53%	21,803	884,653
	CN	-	-	-	-	-	-	13,385,709	2.53%	338,234	13,723,943
	ID	-	-	-	-	-	-	776,668	2.53%	19,625	796,293
	OR	-	-	-	-	-	-	9,384,720	2.53%	237,136	9,621,856
	UT	-	-	-	-	-	-	8,083,603	2.53%	204,259	8,287,862
	WA	-	-	-	-	-	-	7,766,688	2.53%	196,251	7,962,939
	WYP	-	-	-	-	-	-	1,867,921	2.53%	47,199	1,915,120
	WYU	-	-	-	-	-	-	71,330	2.53%	1,802	73,133
Customer Accounts Operations Total		-	-	-	-	-	-	42,199,489		1,066,310	43,265,799
Customer Service Operations											
	CA	-	-	-	-	-	-	101,525	-0.87%	(880)	100,644
	CN	-	-	-	-	-	-	1,369,572	-0.87%	(11,876)	1,357,696
	ID	-	-	-	-	-	-	207,221	-0.87%	(1,797)	205,424
	OR	-	-	-	-	-	-	966,709	-0.87%	(8,382)	958,326
	OTHER	-	-	-	-	-	-	142,988,495	-0.87%	(1,239,877)	141,748,619
	UT	-	-	-	-	-	-	1,500,793	-0.87%	(13,014)	1,487,779
	WA	-	-	-	-	-	-	285,941	-0.87%	(2,479)	283,461
	WYP	-	-	-	-	-	-	296,545	-0.87%	(2,571)	293,973
	WYU	-	-	-	-	-	-	-	-0.87%	-	0
Customer Service Operations Total		-	-	-	-	-	-	147,716,799		(1,280,876)	146,435,923
A&G Operations & Maintenance											
	920	-	-	-	-	702,610	-	1,640,160	5.52%	90,565	1,730,725
	921	-	-	-	-	-	-	18,847,128	1.46%	275,048	19,122,175
	922	-	-	-	-	-	-	(23,711,728)	5.52%	(1,309,297)	(25,021,025)
	923	-	-	-	-	-	-	52,147,713	5.88%	3,063,931	55,211,643
	924	-	-	-	-	-	-	19,550,292	0.00%	-	19,550,292
	925	-	-	-	-	-	-	54,373,523	0.00%	-	54,373,523
	926	-	-	2,967,013	-	-	-	8,589,534	0.00%	-	8,589,534
	928	-	-	-	-	-	-	26,351,519	1.97%	517,941	26,869,461
	929	-	(280,729)	-	-	-	-	17,066,897	5.52%	942,388	18,009,285
	930	-	-	-	(1,349,991)	-	-	861,594	-5.85%	(50,399)	811,195
	931	-	-	-	-	29,534	-	(3,649,240)	6.73%	(245,542)	(3,894,782)
	935	-	-	-	-	-	-	28,004,076	-0.07%	(19,115)	27,984,961
A&G Operations & Maintenance Total		-	(280,729)	2,967,013	(1,349,991)	732,144	-	200,071,467		3,265,518	203,336,986
	Grand Total	(77,418,726)	(1,438,225)	(3,571,949)	(1,349,991)	732,144	(2,095,842)	2,740,225,417		8,413,375	2,748,638,791
										Ref 4.10.3	

PacifiCorp
Oregon General Rate Case - December 2025
O&M Escalation
Escalation Factors

Note: Please see Confidential Exhibit PAC/1705 for details of escalation factors.

	Escalation Factors June 2023 to December 2025	FERC Accounts
STEAM PRODUCTION PLANT		
Operation:	4.84%	500 - 507
Maintenance:	0.31%	510 - 514
HYDRO PRODUCTION PLANT		
Operation:	1.87%	535 - 540
Maintenance:	-0.29%	541 - 545
OTHER PRODUCTION PLANT		
Operation:	4.37%	546 - 550; 556 - 557
Maintenance:	2.38%	551 - 554
TRANSMISSION PLANT		
Operation:	0.07%	560 - 567
Maintenance:	-3.27%	568 - 573
DISTRIBUTION PLANT		
Operation:	2.13%	580 - 589
Maintenance:	-4.41%	590 - 598
CUSTOMER ACCOUNTS		
Operation:	2.53%	901 - 905
CUSTOMER SERVICE and INFORMATION		
Operation:	-0.87%	907 - 910
SALES		
Operation:	3.83%	911 - 916
ADMINISTRATIVE and GENERAL		
Operation:	5.52%	920, 922, 929
Operation:	1.46%	921
Operation:	5.88%	923
Operation:	7.77%	926
Operation:	3.14%	927
Operation:	1.97%	928
Operation:	-5.85%	930
Operation:	6.73%	931
Maintenance:	-0.07%	935

PacifiCorp
Oregon General Rate Case - December 2025
Wildfire and Vegetation O&M

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Remove Base Period Expenses							
Wildfire Mitigation	593	1	(14,166,943)	OR	Situs	(14,166,943)	4.11.1
Wildfire Mitigation	571	1	(963,668)	SG	26.884%	(259,074)	4.11.1
Vegetation Management	593	1	(47,397,760)	OR	Situs	(47,397,760)	4.11.1
Vegetation Management	571	1	(8,181,889)	SG	26.884%	(2,199,632)	4.11.1
Add Test Period Expenses							
Vegetation Management	593	3	67,000,000	OR	Situs	67,000,000	4.11.1

Description of Adjustment

This adjustment removes the wildfire mitigation expenses from the base period as all wildfire mitigation expenses made in accordance with the Company's Wildfire Protection Plan will be recovered through the Automatic Adjustment Clause (AAC). This adjustment also increases the level of vegetation management expenses reflected in base rates from the approved $50 million per docket No. UE-399 to $67 million for the 12 months ending December 2025 as described in the testimony of Company witness Allen L. Berreth.

PacifiCorp
Oregon General Rate Case - December 2025
Wildfire and Vegetation Management O&M

Ln no.		Wildfire Mitigation	Vegetation Management	Ref.
	Expenses in Rates			
1	O&M in Base Rates - CY2022	$ -	$ 30,000,000	*UE-374*
2	O&M in Base Rates - CY2023	$ 19,700,000	$ 50,000,000	*UE-399*
3	O&M in Base Rates - CY2025	*	$ 67,000,000	*Proposed*
	Expenses in Base Period Results			
4	Gross Expense - Situs	$ 36,783,834	$ 60,872,551	
5	Gross Expense - Transmission	$ 963,668	$ 8,181,889	
	Deferral Entries in Base Period Results			
6	Deferral Amounts - Situs	$ 22,616,892	$ 13,474,791	
	Net Expenses reported in Base Period Results			
7	Net Expense - Situs	$ 14,166,943	$ 47,397,760	Line 4 - Line 6
8	Net Expense - Transmission	$ 963,668	$ 8,181,889	Line 5

*The Company will seek recovery of wildfire mitigation O&M amounts through its annual AAC filing (Docket ADV-1529).

PacifiCorp
Oregon General Rate Case - December 2025
Customer Payment Fees

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Customer Account Expense	903	3	4,808,555	OR	Situs	4,808,555	4.12.1

Description of Adjustment:

This adjustment adds into test period results the pro forma incremental expense due to the proposed elimination of payment fees beginning with the effective date of this general rate case. For details, please refer to the direct testimony of company witness Robert M. Meredith.

PacifiCorp
Oregon General Rate Case - December 2025
Customer Payment Fees
Summary of Fees by Type

Customer Accounts Expense	FERC Acct	Alloc.	Total Co. ($)	
Pay Station	903	OR	114,069	
Residential Card Payment	903	OR	2,625,867	
Non-Residential Card Payment	903	OR	2,068,619	
			4,808,555	**Ref. 4.12**

PacifiCorp
Oregon General Rate Case - December 2025
Incremental O&M

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Base Period JB 1 & 2 O&M	512	1	(60,990,000)	SG	26.884%	(16,396,647)	4.13.1
Post Gas-Conv. JB 1 & 2 O&M	512	3	50,104,000	SG	26.884%	13,470,038	4.13.1
Lower Klamath Fish Hatchery O&M	535	1	(402,900)	SG-P	26.884%	(108,316)	4.13.1
Lower Klamath Fish Hatchery O&M	535	3	1,365,909	SG-P	26.884%	367,213	4.13.1

Description of Adjustment:

Jim Bridger plant, units 1 and 2 are expected to be converted to natural gas units by April 2024. This adjustment reflects into test period results the projected operations and maintenance expense changes in post gas-conversion operations. This adjustment also adds in forecast 2025 O&M dollars related to the Lower Klamath Fish Hatchery contractual obligation as it relates to the transfer of Hydroelectric dam assets to KRRC.

PacifiCorp
Oregon General Rate Case - December 2025
Incremental O&M
Pro Forma Operations & Maintenance Expenses

Jim Bridger Units 1 & 2 O&M Expenses

PacifiCorp Share	12 ME June 2023	12 ME Dec 2025
	Actuals	Forecast
Routine	51,347,000	39,426,000
Overhaul	9,643,000	10,678,000
Total	**60,990,000**	**50,104,000**
	Ref 4.13	**Ref 4.13**

Iron Gate Hatchery: KHSA Interim Measure 18 O&M

PacifiCorp Share	12 ME June 2023	12 ME Dec 2025
	Actuals	Forecast
O&M	402,900	1,365,909
	Ref 4.13	**Ref 4.13**

Tab 5 - Net Power Cost

PacifiCorp
Oregon General Rate Case – December 2025
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 2023 provide the starting point for establishing the adjustment amounts for the December 2025 test period.

5.1 NPC Adjustment
5.2 WRAP Fees & COSR Materials

PacifiCorp
Oregon General Rate Case - December 2025
Tab 5 Adjustment Summary

			5.1	5.2
		Total Adjustments	NPC Adjustment	WRAP Fees & COSR Materials
1	Operating ReWenues:			
2	General Business ReWenues	-	-	-
3	Interdepartmental	-	-	-
4	Special Sales	21,491,668	21,491,668	-
5	Other Operating ReWenues	-	-	-
6	Total Operating ReWenues	21,491,668	21,491,668	-
7				
8	Operating Expenses:			
9	Steam Production	(13,786,753)	(13,786,753)	-
10	Nuclear Production	-	-	-
11	Hydro Production	-	-	-
12	Other Power Supply	78,154,638	78,132,506	22,132
13	Transmission	370,746	370,746	-
14	Distribution	-	-	-
15	Customer Accounting	-	-	-
16	Customer SerWice & Info	-	-	-
17	Sales	-	-	-
18	AdministratiWe & General	-	-	-
19				
20	Total O&M Expenses	64,738,631	64,716,499	22,132
21			-	-
22	Depreciation	-	-	-
23	Amortization	-	-	-
24	Taxes Other Than Income	-	-	-
25	Income Taxes - Federal	(8,677,947)	(8,673,508)	(4,439)
26	Income Taxes - State	(1,965,315)	(1,964,309)	(1,005)
27	Income Taxes - Def Net	-	-	-
28	InWestment Tax Credit Adj.	-	-	-
29	Misc ReWenue & Expense	-	-	-
30				
31	Total Operating Expenses:	54,095,369	54,078,682	16,687
32				
33	Operating ReW For Return:	(32,603,701)	(32,587,014)	(16,687)
34				
35	Rate Base:			
36	Electric Plant In SerWice	-	-	-
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	1,618,415	1,617,916	499
45	Weatherization Loans	-	-	-
46	Misc Rate Base	-	-	-
47				
48	Total Electric Plant:	1,618,415	1,617,916	499
49			-	-
50	Rate Base Deductions:		-	-
51	Accum ProW For Deprec	-	-	-
52	Accum ProW For Amort	-	-	-
53	Accum Def Income Tax	-	-	-
54	Unamortized ITC	-	-	-
55	Customer AdW For Const	-	-	-
56	Customer SerWice Deposits	-	-	-
57	Misc Rate Base Deductions	-	-	-
58				
59	Total Rate Base Deductions	-	-	-
60				
61	Total Rate Base:	1,618,415	1,617,916	499
62				
63	Return on Rate Base	-0.665%	-0.664%	0.000%
64				
65	Return on Equity	-1.329%	-1.329%	-0.001%
66				
67	TAX CALCULATION:			
68	Operating ReWenue	(43,246,962)	(43,224,831)	(22,132)
69	Other Deductions	-	-	-
70	Interest (AFUDC)	-	-	-
71	Interest	41,909	41,896	13
72	Schedule "M" Additions	-	-	-
73	Schedule "M" Deductions	-	-	-
74	Income Before Tax	(43,288,871)	(43,266,726)	(22,145)
75				
76	State Income Taxes	(1,965,315)	(1,964,309)	(1,005)
77	Taxable Income	(41,323,556)	(41,302,417)	(21,139)
78				
79	Federal Income Taxes + Other	(8,677,947)	(8,673,508)	(4,439)
	APPROXIMATE PRICE CHANGE	44,948,662	44,925,692	22,970

PacifiCorp PAGE 5.1
Oregon General Rate Case - December 2025
NPC Adjustment

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Revenue:							
Sales for Resale (Account 447)							
Existing Firm PPL	447NPC	3	-	SG	26.884%	-	5.1.1
Existing Firm UPL	447NPC	3	-	SG	26.884%	-	5.1.1
Post-Merger Firm	447NPC	3	79,941,760	SG	26.884%	21,491,668	5.1.1
Non-Firm	447NPC	3	-	SE	26.339%	-	5.1.1
Total Sales for Resale			79,941,760			21,491,668	
Adjustment to Expense:							
Purchased Power (Account 555)							
Existing Firm Demand PPL	555NPC	3	32,827,693	SG	26.884%	8,825,448	5.1.1
Existing Firm Demand UPL	555NPC	3	259,816	SG	26.884%	69,849	5.1.1
Existing Firm Energy	555NPC	3	76,775,318	SE	26.339%	20,221,942	5.1.1
Post-merger Firm	555NPC	3	300,463,569	SG	26.884%	80,777,098	5.1.1
Post-merger Firm - Situs	555NPC	3	(13,361,355)	UT	Situs	-	5.1.1
Post-merger Firm - Situs	555NPC	3	(80,131)	OR	Situs	(80,131)	5.1.1
Post-merger Firm - Situs	555NPC	3	(2,514)	CA	Situs	-	5.1.1
Secondary Purchases	555NPC	3	(20,074,007)	SE	26.339%	(5,287,317)	5.1.1
Total Purchased Power Adjustments:			376,808,388			104,526,890	
Wheeling Expense (Account 565)							
Existing Firm PPL	565NPC	3	18,876,347	SG	26.884%	5,074,747	5.1.1
Existing Firm UPL	565NPC	3	-	SG	26.884%	-	5.1.1
Post-merger Firm	565NPC	3	(3,816,641)	SG	26.884%	(1,026,072)	5.1.1
Non-Firm	565NPC	3	(13,963,753)	SE	26.339%	(3,677,929)	5.1.1
Total Wheeling Expense Adjustments:			1,095,953			370,746	
Fuel Expense (Accounts 501, 503, 547)							
Fuel - Overburden Amortization - Idaho	501NPC	3	(87,693)	ID	Situs	-	5.1.1
Fuel - Overburden Amortization - Wyomin	501NPC	3	(253,319)	WYP	Situs	-	5.1.1
Fuel Consumed - Coal	501NPC	3	(8,799,594)	SE	26.339%	(2,317,735)	5.1.1
Fuel Consumed - Gas	501NPC	3	(37,748,185)	SE	26.339%	(9,942,539)	5.1.1
Steam from Other Sources	503NPC	3	(5,795,480)	SE	26.339%	(1,526,478)	5.1.1
Natural Gas Consumed	547NPC	3	(30,619,520)	SE	26.339%	(8,064,912)	5.1.1
Simple Cycle Combustion Turbines	547NPC	3	15,058,922	SE	26.339%	3,966,387	5.1.1
Cholla / APS Exchange	501NPC	3	-	SE	26.339%	-	5.1.1
Total Fuel Expense Adjustments:			(68,244,870)			(17,885,278)	
Total Power Cost Adjustment			229,717,712			65,520,690	
Post-merger Firm Type 1	555NPC	1	(77,418,726)	SG	26.884%	(20,813,372)	5.1.1
Oregon Situs NPC Adjustments	555NPC	3	(1,482,488)	OR	Situs	(1,482,488)	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 2025. The Aurora study for this adjustment is based on forecast loads for the 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 2025
NPC 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	-	-	-	-	-	-	-	SG
Existing Firm Sales UPL	447.122	-	-	-	-	-	-	-	SG
Post-merger Firm Sales	447.13, .14, .20, .61, .62	262,557,563.32	-	262,557,563	-	262,557,563	342,499,323	79,941,760	SG
Non-firm Sales	447.5	-	-	-	-	-	-	-	SE
Transmission Services	447.9	98,620	(98,620)	-	-	-	-	-	S
On-system Wholesale Sales	447.1	14,218,690	(14,218,690)	-	-	-	-	-	S
Total Revenue Adjustments		276,874,873	(14,317,310)	262,557,563	-	262,557,563	342,499,323	79,941,760	
Purchased Power (Account 555)									
Existing Firm Demand PPL	555.66	-	-	-	-	-	32,827,693	32,827,693	SG
Existing Firm Demand UPL	555.68	-	-	-	-	-	259,816	259,816	SG
Existing Firm Energy	555.65, 555.69	-	-	-	-	-	76,775,318	76,775,318	SE
Post-merger Firm	555.26, .55, .59, .61, .62, .63, .64, .67, .8	1,207,781,184	-	1,207,781,184	-	1,207,781,184	1,430,826,027	223,044,843	SG
Post-merger Firm - Situs	555.27	13,361,355	-	13,361,355	-	13,361,355	-	(13,361,355)	UT
Post-merger Firm - Situs	555.28	80,131	-	80,131	-	80,131	-	(80,131)	OR
Post-merger Firm - Situs	555.29	2,514	-	2,514	-	2,514	-	(2,514)	CA
Secondary Purchases	555.7, 555.25	20,074,007	-	20,074,007	-	20,074,007	-	(20,074,007)	SE
NPC Deferral Mechanism	555.57	(527,209,781)	527,209,781	-	-	-	-	-	OTHER
Seasonal Contracts		-	-	-	-	-	-	-	SG
Wind Integration Charge		-	-	-	-	-	-	-	SG
RPS Compliance Purchases	555.22,555.23,555.24	7,414,297	(7,414,297)	-	-	-	-	-	OTHER
BPA Regional Adjustments	555.11, 555.12, 555.133	-	-	-	-	-	-	-	S
Post-merger Firm Type 1		-	-	-	(77,418,726)	(77,418,726)	-	77,418,726	SG
Total Purchased Power Adjustment		721,503,708	519,795,484	1,241,299,192	(77,418,726)	1,163,880,466	1,540,688,854	376,808,388	
Wheeling (Account 565)									
Existing Firm PPL	565.26	-	-	-	-	-	18,876,347	18,876,347	SG
Existing Firm UPL	565.27	-	-	-	-	-	-	-	SG
Post-merger Firm	565.0, 565.46, 565.1	141,048,505	-	141,048,505	-	141,048,505	137,231,864	(3,816,641)	SG
Non-firm	565.25	25,912,615	-	25,912,615	-	25,912,615	11,948,862	(13,963,753)	SE
Total Wheeling Expense Adjustment		166,961,120	-	166,961,120	-	166,961,120	168,057,073	1,095,953	
Fuel Expense (Accounts 501, 503 and 547)									
Fuel - Overburden Amortization - Idaho	501.12	87,693	-	87,693	-	87,693	-	(87,693)	ID
Fuel - Overburden Amortization - Wyoming	501.12	253,319	-	253,319	-	253,319	-	(253,319)	WY
Fuel Consumed - Coal	501.1	538,681,522	-	538,681,522	-	538,681,522	529,881,928	(8,799,594)	SE
Fuel Consumed - Gas	501.35	62,875,521	-	62,875,521	-	62,875,521	25,127,336	(37,748,185)	SE
Steam From Other Sources	503	11,210,726	-	11,210,726	-	11,210,726	5,415,246	(5,795,480)	SE
Natural Gas Consumed	547.1	621,099,417	-	621,099,417	-	621,099,417	590,479,896	(30,619,520)	SE
Simple Cycle Combustion Turbines	547.1	628,119	-	628,119	-	628,119	15,687,041	15,058,922	SE
Cholla/APS Exchange	501.1	0	-	-	-	-	-	-	SE
Fuel Regulatory Costs Deferral and Amort	501.15	0	-	-	-	-	-	-	S
Fuel Regulatory Costs Deferral and Amort	501.15	482,927	(482,927)	-	-	-	-	-	SE
Miscellaneous Fuel Costs	501.0, .2, .3, .4, .45, .5, .51	21,718,151	(21,718,151)	-	-	-	-	-	SE
Miscellaneous Fuel Costs - Cholla	501.2,501.45	0	-	-	-	-	-	-	SE
Total Fuel Expense		1,257,037,396	(22,201,079)	1,234,836,318	-	1,234,836,318	1,166,591,447	(68,244,870)	
Net Power Cost		**1,868,627,351**	**511,911,715**	**2,380,539,065**	**(77,418,726)**	**2,303,120,340**	**2,532,838,052**	**229,717,712**	
					Ref 5.1		**Ref 5.1.3**	**Ref 5.1**	

PacifiCorp
Oregon General Rate Case - December 2025
Net Power Cost Study

Study Results
MERGED PEAK/ENERGY SPLIT
($)

	Merged 1/2025 - 12/2025	Pre-Merger Demand	Pre-Merger Energy	Non-Firm	Post-Merger
SPECIAL SALES FOR RESALE					
Pacific Pre Merger	-	-			
Post Merger	342,499,323				342,499,323
Utah Pre Merger	-	-			
NonFirm Sub Total	-			-	
	--------------------	--------------------	--------------------	--------------------	--------------------
TOTAL SPECIAL SALES	342,499,323	-	-	-	342,499,323
PURCHASED POWER & NET INTERCHANGE					
BPA Peak Purchase	-	-			
Pacific Capacity	-	-	-		
Mid Columbia	109,312,238	32,793,672	76,518,567		
Misc/Pacific	164,065	34,021	130,044		
Q.F. Contracts/PPL	131,759,964	-	-		131,759,964
Small Purchases west	-		-		
--	--------------------	--------------------	--------------------	--------------------	--------------------
Pacific Sub Total	241,236,268	32,827,693	76,648,611	-	131,759,964
Gemstate	-		-		
GSLM	-		-		
QF Contracts/UPL	184,533,649	259,816	111,350		184,162,484
IPP Layoff	-	-	-		
Small Purchases east	15,358		15,358		
UP&L to PP&L	-	-	-		
--	--------------------	--------------------	--------------------	--------------------	--------------------
Utah Sub Total	184,549,007	259,816	126,707	-	184,162,484
Appaloosa 1A Solar	10,292,182		-		10,292,182
Appaloosa 1B Solar	6,861,455		-		6,861,455
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
Cedar Springs Wind IV	35,181,067		-		35,181,067
Combine Hills Wind	-		-		-
Cove Mountain Solar	3,802,638		-		3,802,638
Cove Mountain Solar II	9,387,257		-		9,387,257
Deseret Purchase	-		-		-
Eagle Mountain - UAMPS/UMPA	-		-		-
Elektron Solar 20yr	-		-		-
Elektron Solar 25yr	-		-		-
Graphite Solar	6,197,453		-		6,197,453
Hermiston Purchase	-		-		-
Horseshoe Solar	6,072,682		-		6,072,682
Hunter Solar	6,980,641		-		6,980,641
Hurricane Purchase	-		-		-
MagCorp Buythrough	-		-		-
MagCorp Reserves	-		-		-
Milican Solar	2,973,753		-		2,973,753
Milford Solar	6,870,872		-		6,870,872
Nucor	7,129,800		-		7,129,800
Old Mill Solar	-		-		-
Monsanto Reserves	20,600,000		-		20,600,000
Pavant III Solar	-		-		-
PGE Cove	164,065		-		-
Prineville Solar	1,981,228		-		1,981,228
Sigurd Solar	5,858,273		-		5,858,273
Soda Lake Geothermal	-		-		-
Three Buttes Wind	20,609,802		-		20,609,802
Top of the World Wind	36,087,543		-		36,087,543
Wolverine Creek Wind	10,693,967		-		10,693,967
Faraday B Solar	7,312,704		-		7,312,704
Hornshadow I Solar	4,743,533		-		4,743,533
Hornshadow II Solar	9,487,066		-		9,487,066
Green River Energy Center	-		-		-
Anticline Wind	17,957,893		-		17,957,893
Boswell Springs Wind	33,509,492		-		33,509,492
Two River Wind LLC	-		-		-

PacifiCorp
Oregon General Rate Case - December 2025
Net Power Cost Study

Study Results
MERGED PEAK/ENERGY SPLIT
($)

	Merged 1/2025 - 12/2025	Pre-Merger Demand	Pre-Merger Energy	Non-Firm	Post-Merger
Cedar Creek	20,759,802		-		20,759,802
UT Schedule Adjustment	(46,985,993)		-		(46,985,993)
OR Schedule 126 CSP	4,237,671		-		4,237,671
Rush lake_BESS	-		-		-
Fremont Solar_BESS	-		-		-
Green River Energy Center_BESS	-		-		-
Umpqua Storage Placeholder	-		-		-
Short Term Firm Purchases	839,196,010		-		839,196,010
New Firm Sub Total	1,115,067,645	-	-	-	1,114,903,579
Non Firm Sub Total	-			-	
TOTAL PURCHASED PW & NET INT.	1,540,688,854	33,087,508	76,775,318	-	1,430,826,027
WHEELING & U. OF F. EXPENSE					
Pacific Firm Wheeling and Use of Facilities	18,876,347	18,876,347			
Utah Firm Wheeling and Use of Facilities	-	-			
Post Merger	137,231,864				137,231,864
Nonfirm Wheeling	11,948,862			11,948,862	
TOTAL WHEELING & U. OF F. EXPENSE	168,057,073	18,876,347	-	11,948,862	137,231,864
THERMAL FUEL BURN EXPENSE					
Colstrip	19,768,554			19,768,554	
Craig	19,102,358			19,102,358	
Dave Johnston	56,028,158			56,028,158	
Hayden	10,375,880			10,375,880	
Hunter	162,928,319			162,928,319	
Huntington	82,218,000			82,218,000	
Jim Bridger	118,954,269			118,954,269	
Naughton	36,164,475			36,164,475	
Wyodak	24,341,915			24,341,915	
Chehalis	98,926,957			98,926,957	
Currant Creek	71,432,588			71,432,588	
Gadsby	25,127,336			25,127,336	
Gadsby CT	15,687,041			15,687,041	
Hermiston	36,017,802			36,017,802	
Jim Bridger - Gas	103,123,779			103,123,779	
Lake Side 1	99,629,572			99,629,572	
Lake Side 2	97,291,060			97,291,060	
Naughton - Gas	21,831,664			21,831,664	
Gas Physical	(2,145,401)			(2,145,401)	
Gas Swaps	17,955,035			17,955,035	
Clay Basin Gas Storage	(1,048,150)			(1,048,150)	
Pipeline Reservation Fees	47,464,991			47,464,991	
TOTAL FUEL BURN EXPENSE	1,161,176,202	-	-	1,161,176,202	-
OTHER GENERATION EXPENSE					
Blundell	5,415,246			5,415,246	
TOTAL OTHER GEN. EXPENSE	5,415,246	-	-	5,415,246	-
NET POWER COST	2,532,838,052	51,963,855	76,775,318	1,178,540,310	1,225,558,569

PacifiCorp
Oregon General Rate Case - December 2025
NPC Adjustment
Oregon Situs Adjustments

	Total	**Jan-25**	**Feb-25**	**Mar-25**	**Apr-25**	**May-25**	**Jun-25**	**Jul-25**	**Aug-25**	**Sep-25**	**Oct-25**	**Nov-25**	**Dec-25**
Net Energy impact - Situs Solar	**(1,153,813)**	(40,994)	(62,225)	(55,533)	(53,953)	(61,240)	(74,114)	(223,660)	(250,852)	(178,605)	(67,322)	(43,138)	(42,176)
REP Adjustments (Total Company)	**(2,493,844)**	(195,345)	(153,730)	(228,065)	(308,244)	(363,603)	(573,026)	(112,079)	148,892	152,921	(314,683)	(270,191)	(276,690)
Allocated on SG Factor (26.884%)	**(670,449)**	(52,517)	(41,329)	(61,313)	(82,869)	(97,752)	(154,053)	(30,132)	40,028	41,112	(84,600)	(72,639)	(74,386)
REP Adjustments (Oregon Allocation)	**341,774**	107,206	46,182	113,431	119,589	109,294	297,314	(122,865)	(308,240)	(266,475)	93,596	74,887	77,856
Total OR Situs Adjustment	**(1,482,488)**	13,694	(57,373)	(3,416)	(17,233)	(49,697)	69,146	(376,657)	(519,063)	(403,968)	(58,326)	(40,889)	(38,706)

PacifiCorp
Oregon General Rate Case - December 2025
WRAP Fees & COSR Materials

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
WRAP Fee	557	3	22,137	SG	26.884%	5,951	5.2.1
COSR Materials	557	3	60,186	SG	26.884%	16,180	5.2.1

Description of Adjustment:

The first adjustment reflect into test year base rates results two specific fee items. 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 Northwest Power Pool (NWPP) region, through the development and implementation of a Western Resource Adequacy Program (WRAP). The second fee is regarding the Committee of State Regulators (COSR) fees which are related to the WRAP Program.

PacifiCorp
Oregon General Rate Case - December 2025
WRAP Fees & COSR Materials

Incremental O&M	12 ME June 2023	Forecasted Total	Adjustment	
Western Resource Adequacy Program (WRAP)	$ 1,029,863	$ 1,052,000	$ 22,137	
COSR Materials	$ -	$ 60,186	$ 60,186	
	$ 1,029,863	**$ 1,112,186**	**$ 82,323**	**Ref 5.2**

Tab 4 - Bcnpcag_rgml $?kmprgx_rgml

Oregon General Rate Case – December 2025
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 and Amortization Reserve
6.3 Repowering Buy-Downs Adjustment
6.4 Confidential Bridger Coal Reclamation Costs

PacifiCorp
Oregon General Rate Case - December 2025
Tab 6 Adjustment Summary

		Total Adjustments	6.1 Depreciation & Amortiation Expense	6.2 Depreciation & Amortization Reserve	6.3 Repowering Buy Downs Adjustment	6.4 Bridger Coal Reclamation Costs_CONF
1	Operating ReWenues:					
2	General Business ReWenues	-	-	-	-	-
3	Interdepartmental	-	-	-	-	-
4	Special Sales	-	-	-	-	-
5	Other Operating ReWenues	-	-	-	-	-
6	Total Operating ReWenues	-	-	-	-	-
7						
8	Operating Expenses:					
9	Steam Production	3,818,882	-	-	-	3,818,882
10	Nuclear Production	-	-	-	-	-
11	Hydro Production	-	-	-	-	-
12	Other Power Supply	-	-	-	-	-
13	Transmission	-	-	-	-	-
14	Distribution	-	-	-	-	-
15	Customer Accounting	-	-	-	-	-
16	Customer SerWice & Info	-	-	-	-	-
17	Sales	-	-	-	-	-
18	AdministratiWe & General	-	-	-	-	-
19						
20	Total O&M Expenses	3,818,882	-	-	-	3,818,882
21						
22	Depreciation	40,255,866	41,091,690	(835,824)	-	-
23	Amortization	(2,716,107)	4,032,446	-	(6,748,553)	-
24	Taxes Other Than Income	-	-	-	-	-
25	Income Taxes - Federal	(3,114,987)	(9,044,132)	3,647,227	2,250,852	31,066
26	Income Taxes - State	(705,458)	(2,048,246)	825,996	509,756	7,036
27	Income Taxes - Def Net	(938,932)	-	-	-	(938,932)
28	InWestment Tax Credit Adj.	-	-	-	-	-
29	Misc ReWenue & Expense	-	-	-	-	-
30						
31	Total Operating Expenses:	36,599,264	34,031,758	3,637,399	(3,987,945)	2,918,052
32						
33	Operating ReW For Return:	(36,599,264)	(34,031,758)	(3,637,399)	3,987,945	(2,918,052)
34						
35	Rate Base:					
36	Electric Plant In SerWice	-	-	-	-	-
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	(47)	(331,860)	133,829	82,591	115,392
45	Weatherization Loans	-	-	-	-	-
46	Misc Rate Base	-	-	-	-	-
47						
48	Total Electric Plant:	(47)	(331,860)	133,829	82,591	115,392
49		-	-	-	-	-
50	Rate Base Deductions:	-	-	-	-	-
51	Accum ProW For Deprec	(817,609,078)	-	(644,536,440)	(173,072,637)	-
52	Accum ProW For Amort	(25,921,413)	-	(25,921,413)	-	-
53	Accum Def Income Tax	1,988,755	-	-	-	1,988,755
54	Unamortized ITC	-	-	-	-	-
55	Customer AdW For Const	-	-	-	-	-
56	Customer SerWice Deposits	-	-	-	-	-
57	Misc Rate Base Deductions	(8,088,788)	-	-	-	(8,088,788)
58						
59	Total Rate Base Deductions	(849,630,523)	-	(670,457,853)	(173,072,637)	(6,100,033)
60						
61	Total Rate Base:	(849,630,570)	(331,860)	(670,324,024)	(172,990,046)	(5,984,640)
62						
63	Return on Rate Base	0.632%	-0.691%	0.962%	0.420%	-0.060%
64						
65	Return on Equity	1.264%	-1.381%	1.924%	0.841%	-0.120%
66						
67	TAX CALCULATION:					
68	Operating ReWenue	(41,358,641)	(45,124,137)	835,824	6,748,553	(3,818,882)
69	Other Deductions	-	-	-	-	-
70	Interest (AFUDC)	-	-	-	-	-
71	Interest	(22,001,031)	(8,593)	(17,357,920)	(4,479,546)	(154,971)
72	Schedule "M" Additions	3,818,882	-	-	-	3,818,882
73	Schedule "M" Deductions	-	-	-	-	-
74	Income Before Tax	(15,538,728)	(45,115,543)	18,193,744	11,228,099	154,971
75						
76	State Income Taxes	(705,458)	(2,048,246)	825,996	509,756	7,036
77	Taxable Income	(14,833,270)	(43,067,297)	17,367,748	10,718,344	147,935
78						
79	Federal Income Taxes + Other	(3,114,987)	(9,044,132)	3,647,227	2,250,852	31,066
	APPROXIMATE PRICE CHANGE	(40,051,957)	46,702,585	(66,260,142)	(23,865,768)	3,371,368

PacifiCorp
Oregon General Rate Case - December 2025
Depreciation Expense

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Steam Depreciation Expense	403SP	3	453,838	SG	26.884%	122,011	
Steam Depreciation Expense	403SP	3	14,770,434	SG	26.884%	3,970,907	
Steam Depreciation Expense	403SP	3	57,315,161	SG	26.884%	15,408,698	
Steam Depreciation Expense	403SP	3	6,748,935	OTHER	0.000%	-	
Hydro Depreciation Expense	403HP	3	(11,304,795)	SG	26.884%	(3,039,199)	
Hydro Depreciation Expense	403HP	3	(74,021)	SG	26.884%	(19,900)	
Hydro Depreciation Expense	403HP	3	13,816,525	SG-P	26.884%	3,714,456	
Hydro Depreciation Expense	403HP	3	1,513,249	SG-U	26.884%	406,824	
Other Depreciation Expense	403OP	3	-	SG	26.884%	-	
Other Depreciation Expense	403OP	3	(1,682,495)	SG	26.884%	(452,325)	
Other Depreciation Expense	403OP	3	(3,343,833)	SG-W	26.884%	(898,961)	
Other Depreciation Expense	403OP	3	61,215	OR	Situs	61,215	
Other Depreciation Expense	403OP	3	(19,899)	UT	Situs	-	
Other Depreciation Expense	403OP	3	(11,849)	SG	26.884%	(3,186)	
Transmission Depreciation Expense	403TP	3	(245,682)	SG	26.884%	(66,050)	
Transmission Depreciation Expense	403TP	3	(209,097)	SG	26.884%	(56,214)	
Transmission Depreciation Expense	403TP	3	55,948,753	SG	26.884%	15,041,351	
Distribution Depreciation Expense	403360	3	248,530	OR	Situs	31,749	
Distribution Depreciation Expense	403361	3	476,764	OR	Situs	60,906	
Distribution Depreciation Expense	403362	3	4,001,040	OR	Situs	511,128	
Distribution Depreciation Expense	403364	3	4,925,548	OR	Situs	629,233	
Distribution Depreciation Expense	403365	3	3,085,365	OR	Situs	394,152	
Distribution Depreciation Expense	403366	3	1,566,422	OR	Situs	200,109	
Distribution Depreciation Expense	403367	3	3,567,853	OR	Situs	455,789	
Distribution Depreciation Expense	403368	3	5,208,630	OR	Situs	665,397	
Distribution Depreciation Expense	403369	3	3,322,750	OR	Situs	424,478	
Distribution Depreciation Expense	403370	3	942,521	OR	Situs	120,406	
Distribution Depreciation Expense	403371	3	28,491	OR	Situs	3,640	
Distribution Depreciation Expense	403373	3	202,908	OR	Situs	25,921	
General Depreciation Expense	403GP	3	49,660	CA	Situs	-	
General Depreciation Expense	403GP	3	1,368,313	OR	Situs	1,368,313	
General Depreciation Expense	403GP	3	113,194	WA	Situs	-	
General Depreciation Expense	403GP	3	219,279	WYP	Situs	-	
General Depreciation Expense	403GP	3	514,179	UT	Situs	-	
General Depreciation Expense	403GP	3	74,752	ID	Situs	-	
General Depreciation Expense	403GP	3	(21,202)	WYU	Situs	-	
General Depreciation Expense	403GP	3	(792)	SG	26.884%	(213)	
General Depreciation Expense	403GP	3	(5,823)	SG	26.884%	(1,566)	
General Depreciation Expense	403GP	3	(21,362)	SG	26.884%	(5,743)	
General Depreciation Expense	403GP	3	7,540,872	SO	27.425%	2,068,119	
General Depreciation Expense	403GP	3	-	SG	26.884%	-	
General Depreciation Expense	403GP	3	618	SG	26.884%	166	
General Depreciation Expense	403GP	3	(162,922)	CN	30.706%	(50,026)	
General Depreciation Expense	403GP	3	391	SE	26.339%	103	
			170,982,421			41,091,690	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 2024 depreciation and amortization expense for the test period is calculated by applying the current composite depreciation and amortization rates to the December 2024 projected plant balances.

PacifiCorp
Oregon General Rate Case - December 2025
Amortization Expense

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Intangible Amortization	404IP	3	(858)	CA	Situs	-	
Intangible Amortization	404IP	3	(100,527)	CN	30.706%	(30,867)	
Intangible Amortization	404IP	3	(967)	SG	26.884%	(260)	
Intangible Amortization	404IP	3	(78,646)	SG	26.884%	(21,143)	
Intangible Amortization	404IP	3	(14,703)	ID	Situs	-	
Intangible Amortization	404IP	3	(121)	OR	Situs	(121)	
Intangible Amortization	404IP	3	(879)	SE	26.339%	(232)	
Intangible Amortization	404IP	3	(7,319,211)	SG	26.884%	(1,967,708)	
Intangible Amortization	404IP	3	(16,651)	SG-P	26.884%	(4,476)	
Intangible Amortization	404IP	3	(9,653)	SG-U	26.884%	(2,595)	
Intangible Amortization	404IP	3	(2,104,993)	OTHER	0.000%	-	
Intangible Amortization	404IP	3	22,193,396	SO	27.425%	6,086,642	
Intangible Amortization	404IP	3	16,843	UT	Situs	-	
Intangible Amortization	404IP	3	(1,512)	WA	Situs	-	
Intangible Amortization	404IP	3	(153,645)	WYP	Situs	-	
Intangible Amortization	404IP	3	-	WYU	Situs	-	
Hydro Amortization	404HP	3	-	SG	26.884%	-	
Hydro Amortization	404HP	3	296	SG-P	26.884%	80	
Hydro Amortization	404HP	3	-	SG-U	26.884%	-	
Other Amortization	404OP	3	10,991	OR	Situs	10,991	
General Amortization	404GP	3	269	CA	Situs	-	
General Amortization	404GP	3	-	CN	30.706%	-	
General Amortization	404GP	3	(5,423)	OR	Situs	(5,423)	
General Amortization	404GP	3	(118,291)	SO	27.425%	(32,442)	
General Amortization	404GP	3	-	UT	Situs	-	
General Amortization	404GP	3	10,633	WA	Situs	-	
General Amortization	404GP	3	31,360	WYP	Situs	-	
General Amortization	404GP	3	-	ID	Situs	-	
			12,337,709			4,032,446	6.1.3
Total Adjustment			183,320,130			45,124,137	6.1.3

Description of Adjustment:

This adjustment reflects the incremental depreciation expense that is calculated on the plant additions included in this filing in adjustment 8.4. The annualized 2024 depreciation and amortization expense for the test period is calculated by applying the current composite depreciation and amortization rates to the December 2024 projected plant balances.

PacifiCorp
Oregon General Rate Case - December 2025
Depreciation and Amortization Expense Summary

Description	Account	Factor	12 ME Jun 2023 Expense	Test Period Expense	Adjustment to Test Period
DEPRECIATION EXPENSE					
Steam Production Plant:					
Pre-merger Pacific	403SP	SG	50,674,954	51,128,792	453,838
Pre-merger Utah	403SP	SG	37,646,705	52,417,139	14,770,434
Post-merger	403SP	SG	264,110,600	321,425,761	57,315,161
Post-merger	403SP	OTHER	(6,748,935)	-	6,748,935
Total Steam Plant			345,683,324	424,971,693	79,288,368
Hydro Production Plant:					
Pre-merger Pacific	403HP	SG	15,346,394	4,041,599	(11,304,795)
Pre-merger Utah	403HP	SG	1,316,807	1,242,786	(74,021)
Post-merger	403HP	SG-P	7,569,306	21,385,831	13,816,525
Post-merger	403HP	SG-U	7,571,738	9,084,988	1,513,249
Total Hydro Plant			31,804,245	35,755,204	3,950,959
Other Production Plant:					
Pre-merger Utah	403OP	SG	-	-	-
Post-merger	403OP	SG	70,324,552	68,642,057	(1,682,495)
Post-merger Wind	403OP	SG-W	143,905,228	140,561,395	(3,343,833)
Post-merger Wind	403OP	OR	158	61,373	61,215
Post-merger Wind	403OP	UT	19,899	-	(19,899)
Post-merger	403OP	SG	4,283,251	4,271,402	(11,849)
Total Other Production Plant			218,533,087	213,536,227	(4,996,861)
Transmission Plant:					
Pre-merger Pacific	403TP	SG	8,251,666	8,005,984	(245,682)
Pre-merger Utah	403TP	SG	10,327,742	10,118,645	(209,097)
Post-merger	403TP	SG	119,677,406	175,626,159	55,948,753
Total Transmission Plant			138,256,814	193,750,789	55,493,974
Distribution Plant:					
California	403364	CA	9,648,505	15,618,897	5,970,392
Oregon	403364	OR	58,047,724	61,570,633	3,522,909
Washington	403364	WA	15,840,746	17,099,473	1,258,727
Eastern Wyoming	403364	WYP	19,644,501	20,607,376	962,875
Utah	403364	UT	92,584,975	107,174,945	14,589,971
Idaho	403364	ID	10,828,775	11,921,466	1,092,691
Western Wyoming	403364	WYU	3,862,216	4,041,475	179,259
Total Distribution Plant			210,457,441	238,034,265	27,576,823
General Plant:					
California	403GP	CA	448,977	498,637	49,660
Oregon	403GP	OR	5,055,867	6,424,180	1,368,313
Washington	403GP	WA	1,113,036	1,226,231	113,194
Eastern Wyoming	403GP	WYP	2,205,106	2,424,385	219,279
Utah	403GP	UT	6,120,098	6,634,278	514,179
Idaho	403GP	ID	1,157,698	1,232,450	74,752
Western Wyoming	403GP	WYU	446,687	425,485	(21,202)
Pre-merger Pacific	403GP	SG	6,539	5,747	(792)
Pre-merger Utah	403GP	SG	34,736	28,913	(5,823)
Post-merger	403GP	SG	11,268,948	11,247,587	(21,362)
General Office	403GP	SO	20,313,717	27,854,589	7,540,872
General Office	403GP	SG	-	-	-
General Office	403GP	SG	9,078	9,696	618
Customer Service	403GP	CN	872,675	709,753	(162,922)
Fuel Related	403GP	SE	112,428	112,819	391
Total General Plant			49,165,591	58,834,749	9,669,158
Total Depreciation Expense			993,900,504	1,164,882,926	**170,982,421**
					Ref 6.1

PacifiCorp
Oregon General Rate Case - December 2025
Depreciation and Amortization Expense Summary

Description	Account	Factor	12 ME Jun 2023 Expense	Test Period Expense	Adjustment to Test Period
AMORTIZATION EXPENSE					
Intangible Plant:					
California	404IP	CA	858	-	(858)
Customer Service	404IP	CN	15,686,362	15,585,835	(100,527)
Pre-merger Utah	404IP	SG	12,470	11,504	(967)
Pre-merger Pacific	404IP	SG	78,646	-	(78,646)
Idaho	404IP	ID	14,703	-	(14,703)
Oregon	404IP	OR	11,336	11,216	(121)
Fuel Related	404IP	SE	1,821	942	(879)
Post-merger	404IP	SG	13,211,793	5,892,582	(7,319,211)
Hydro Relicensing	404IP	SG-P	2,697,182	2,680,531	(16,651)
Hydro Relicensing	404IP	SG-U	324,280	314,627	(9,653)
Post-merger	404IP	OTHER	2,104,993	-	(2,104,993)
General Office	404IP	SO	28,903,296	51,096,692	22,193,396
Utah	404IP	UT	80,728	97,571	16,843
Washington	404IP	WA	1,636	125	(1,512)
Eastern Wyoming	404IP	WYP	221,242	67,597	(153,645)
Western Wyoming	404IP	WYU	-	-	-
Total Intangible Plant			63,351,348	75,759,221	12,407,874
Hydro Production Plant:					
Pre-merger Pacific	404HP	SG	-	-	-
Post-merger	404HP	SG-P	313,582	313,878	296
Post-merger	404HP	SG-U	-	-	-
Total Hydro Plant			313,582	313,878	296
Other Production Plant:					
Oregon	404OP	OR	59,650	70,641	10,991
Total Other Plant			59,650	70,641	10,991
General Plant:					
California	404GP	CA	-	269	269
General Office	404GP	CN	-	-	-
Oregon	404GP	OR	145,001	139,579	(5,423)
General Office	404GP	SO	159,654	41,363	(118,291)
Utah	404GP	UT	-	-	-
Washington	404GP	WA	97,228	107,861	10,633
Eastern Wyoming	404GP	WYP	141,804	173,163	31,360
Idaho	404GP	ID	-	-	-
Total General Plant			543,687	462,235	(81,452)
Total Amortization			64,268,267	76,605,976	**12,337,709**
					Ref 6.1.1
Total Depreciation and Amortization			1,058,168,771	**1,241,488,901**	**183,320,130**
				Ref. 6.1.13	**Ref 6.1.1**

PacifiCorp
Oregon General Rate Case - December 2025
Jun 2023 - Dec 2024 Depreciation & Amortization Expense

Description	Factor	2018 Rate	Adjusted EPIS Balance Jun 2023	Depreciation Expense Jun 2023	Adjustments	Adjusted EPIS Balance Jul 2023	Depreciation Expense Jul 2023	Adjustments	Adjusted EPIS Balance Aug 2023	Depreciation Expense Aug 2023
DEPRECIATION EXPENSE										
Steam Production Plant:										
Pre-merger Pacific	SG	5.094%	1,008,703,226	4,282,018	(278,562)	1,008,424,665	4,281,427	(278,562)	1,008,146,103	4,280,244
Pre-merger Utah	SG	5.005%	1,051,760,466	4,386,481	(244,912)	1,051,515,555	4,385,970	(244,912)	1,051,270,643	4,384,949
Post-merger	SG	6.327%	4,926,894,994	25,978,609	(84,053)	4,926,810,940	25,978,387	1,330,295	4,928,141,236	25,981,673
Geothermal - Blundell	SG	6.327%	30,046,813	158,431	-	30,046,813	158,431	-	30,046,813	158,431
Carbon	SG	6.327%	-	-	-	-	-	-	-	-
Pollution Control Equipment	SG	6.327%	-	-	168,873	168,873	445	-	168,873	890
Pollution Control Equipment	SG	0.000%	-	-	-	-	-	-	-	-
Post-merger	SG	0.000%	1,266,851	-	-	1,266,851	-	-	1,266,851	-
Total Steam Plant			7,018,672,351	34,805,538	(438,654)	7,018,233,697	34,804,660	806,822	7,019,040,519	34,806,187
Hydro Production Plant:										
Pre-merger Pacific	SG	2.208%	183,725,898	338,116	(39,742)	183,686,156	338,080	(39,742)	183,646,415	338,007
Pre-merger Utah	SG	3.187%	39,600,570	105,176	(33,680)	39,566,890	105,131	(33,680)	39,533,209	105,041
Post-merger	SG-P	2.767%	663,567,761	1,530,012	1,952,440	665,520,201	1,532,263	1,405,537	666,925,738	1,536,134
Post-merger	SG-U	4.631%	165,769,344	639,766	(131,663)	165,637,680	639,512	83,242	165,720,922	639,418
Klamath - New Capital	SG-P	20.000%	-	-	-	-	-	-	-	-
Future Use	Future Use		-		-	-		-	-	
Total Hydro Plant			1,052,663,572	2,613,070	1,747,354	1,054,410,927	2,614,986	1,415,357	1,055,826,284	2,618,601
Other Production Plant:										
Pre-merger Utah	SG	0.000%	235,129	-	-	235,129	-	-	235,129	-
Post-merger	SG	3.505%	1,944,497,799	5,679,168	(2,001,958)	1,942,495,841	5,676,245	(2,049,187)	1,940,446,654	5,670,329
Post-merger Wind	SG-W	4.208%	3,225,445,773	11,311,345	354,332	3,225,800,105	11,311,966	1,088,935	3,226,889,040	11,314,497
Oregon Solar	OR	13.675%	78,742	897	125,080	203,822	1,610	124,887	328,709	3,034
Post-merger	SG	4.832%	88,883,413	357,896	(66,123)	88,817,290	357,763	(66,123)	88,751,167	357,496
Total Other Plant			5,259,140,856	17,349,306	(1,588,669)	5,257,552,187	17,347,583	(901,487)	5,256,650,700	17,345,356
Transmission Plant:										
Pre-merger Pacific	SG	1.699%	474,654,963	671,961	(188,188)	474,466,774	671,828	(188,188)	474,278,586	671,561
Pre-merger Utah	SG	1.672%	611,506,343	851,960	(348,507)	611,157,837	851,717	(348,507)	610,809,330	851,232
Post-merger	SG	1.725%	7,002,292,488	10,064,866	17,455,509	7,019,747,997	10,077,411	23,375,592	7,043,123,588	10,106,755
Total Transmission Plant			8,088,453,794	11,588,787	16,918,814	8,105,372,608	11,600,956	22,838,897	8,128,211,505	11,629,548
Distribution Plant:										
California	CA	2.710%	387,052,668	874,081	3,606,955	390,659,622	878,153	3,467,705	394,127,327	886,142
Oregon	OR	2.276%	2,591,555,458	4,914,814	5,115,069	2,596,670,527	4,919,664	6,957,509	2,603,628,036	4,931,112
Washington	WA	2.581%	626,391,983	1,347,167	2,859,292	629,251,275	1,350,241	3,202,326	632,453,601	1,356,760
Eastern Wyoming	WYP	2.657%	741,523,302	1,641,680	1,164,856	742,688,158	1,642,970	2,513,629	745,201,787	1,647,042
Utah	UT	2.548%	3,731,611,811	7,923,780	19,091,980	3,750,703,791	7,944,050	20,753,144	3,771,456,936	7,986,354
Idaho	ID	2.540%	434,569,369	919,856	2,202,579	436,771,948	922,188	1,402,176	438,174,124	926,003
Western Wyoming	WYU	2.654%	153,080,209	338,605	(45,586)	153,034,623	338,554	(45,586)	152,989,037	338,453
Total Distribution Plant			8,665,784,800	17,959,983	33,995,144	8,699,779,944	17,995,821	38,250,903	8,738,030,847	18,071,866
General Plant:										
California	CA	2.087%	22,900,031	39,822	14,990	22,915,021	39,835	(47,444)	22,867,577	39,807
Oregon	OR	2.291%	219,897,704	419,805	1,142,369	221,040,072	420,895	502,267	221,542,340	422,465
Washington	WA	2.294%	48,898,473	93,485	246,686	49,145,160	93,721	(73,284)	49,071,876	93,887
Eastern Wyoming	WYP	2.306%	96,943,140	186,263	(34,496)	96,908,644	186,230	127,370	97,036,014	186,319
Utah	UT	2.154%	284,312,573	510,332	4,185,316	288,497,889	514,089	1,968,175	290,466,064	519,611
Idaho	ID	2.029%	57,929,280	97,927	(28,272)	57,901,007	97,903	259,635	58,160,642	98,099
Western Wyoming	WYU	2.087%	20,825,570	36,217	(24,286)	20,801,284	36,196	(24,286)	20,776,998	36,154
Pre-merger Pacific	SG	1.090%	691,832	628	(9,135)	682,697	624	(9,135)	673,562	616
Pre-merger Utah	SG	1.196%	2,903,299	2,895	(27,040)	2,876,259	2,881	(27,040)	2,849,219	2,854
Post-merger	SG	3.474%	333,494,863	965,574	(613,108)	332,881,755	964,686	(598,526)	332,283,229	962,932
General Office	SO	6.249%	375,901,876	1,957,378	752,492	376,654,368	1,959,337	32,473	376,686,841	1,961,381
General Office	SG	0.000%	-	-	-	-	-	-	-	-
General Office	SG	4.285%	227,520	812	(67)	227,452	812	(67)	227,385	812
Customer Service	CN	5.135%	15,746,220	67,383	(106,932)	15,639,288	67,154	(106,932)	15,532,356	66,696
Fuel Related	SE	3.583%	3,349,862	10,001	(11,152)	3,338,710	9,984	(11,152)	3,327,558	9,951
Total General Plant			1,484,022,244	4,388,522	5,487,363	1,489,509,607	4,394,348	1,992,053	1,491,501,660	4,401,584
Mining Plant:										
Coal Mine	SE	0.000%	1,822,901	-	-	1,822,901	-	-	1,822,901	-
Total Mining Plant			1,822,901	-	-	1,822,901	-	-	1,822,901	-
Total Depreciation Expense			31,570,560,516	88,705,206	56,121,353	31,626,681,870	88,758,354	64,402,545	31,691,084,414	88,873,142

Description	Adjustments	Adjusted EPIS Balance Sep 2023	Depreciation Expense Sep 2023	Adjustments	Adjusted EPIS Balance Oct 2023	Depreciation Expense Oct 2023
DEPRECIATION EXPENSE						
Steam Production Plant:						
Pre-merger Pacific	(278,562)	1,007,867,542	4,279,062	(278,562)	1,007,588,980	4,277,879
Pre-merger Utah	(244,912)	1,051,025,732	4,383,927	(244,912)	1,050,780,820	4,382,906
Post-merger	36,095,478	4,964,236,714	26,080,342	204,683	4,964,441,397	26,176,044
Geothermal - Blundell	-	30,046,813	158,431	-	30,046,813	158,431
Carbon	-	-	-	-	-	-
Pollution Control Equipment	-	168,873	890	-	168,873	890
Pollution Control Equipment	-	-	-	-	-	-
Post-merger	-	1,266,851	-	-	1,266,851	-
Total Steam Plant	35,572,005	7,054,612,524	34,902,653	(318,791)	7,054,293,733	34,996,151
Hydro Production Plant:						
Pre-merger Pacific	(39,742)	183,606,673	337,934	(39,742)	183,566,931	337,860
Pre-merger Utah	(33,680)	39,499,529	104,952	(33,680)	39,465,849	104,863
Post-merger	3,023,024	669,948,762	1,541,240	2,775,309	672,724,071	1,547,925
Post-merger	20,244	165,741,167	639,618	8,579	165,749,745	639,674
Klamath - New Capital	-	-	-	-	-	-
Future Use	-	-		-	-	
Total Hydro Plant	2,969,847	1,058,796,131	2,623,744	2,710,466	1,061,506,596	2,630,321
Other Production Plant:						
Pre-merger Utah	-	235,129	-	-	235,129	-
Post-merger	(2,049,187)	1,938,397,467	5,664,344	35,127,063	1,973,524,530	5,712,648
Post-merger Wind	1,472,727	3,228,361,767	11,318,989	1,586,136	3,229,947,903	11,324,352
Oregon Solar	-	328,709	3,746	-	328,709	3,746
Post-merger	(66,123)	88,685,045	357,230	10,818	88,695,863	357,119
Total Other Plant	(642,582)	5,256,008,117	17,344,308	36,724,016	5,292,732,134	17,397,865
Transmission Plant:						
Pre-merger Pacific	(188,188)	474,090,398	671,295	(188,188)	473,902,210	671,028
Pre-merger Utah	(348,507)	610,460,824	850,746	(348,507)	610,112,317	850,261
Post-merger	10,763,642	7,053,887,230	10,131,291	20,794,442	7,074,681,672	10,153,971
Total Transmission Plant	10,226,947	8,138,438,452	11,653,332	20,257,747	8,158,696,199	11,675,260
Distribution Plant:						
California	14,166,025	408,293,351	906,053	13,491,583	421,784,934	937,282
Oregon	18,556,326	2,622,184,362	4,955,305	5,259,959	2,627,444,321	4,977,889
Washington	431,529	632,885,130	1,360,667	316,674	633,201,803	1,361,472
Eastern Wyoming	1,344,915	746,546,702	1,651,313	1,073,230	747,619,932	1,653,990
Utah	11,841,782	3,783,298,717	8,020,961	22,939,705	3,806,238,422	8,057,889
Idaho	1,466,603	439,640,727	929,039	1,095,690	440,736,417	931,751
Western Wyoming	(45,586)	152,943,451	338,352	(45,586)	152,897,866	338,252
Total Distribution Plant	47,761,594	8,785,792,440	18,161,690	44,131,255	8,829,923,695	18,258,524
General Plant:						
California	(2,989)	22,864,588	39,763	14,317	22,878,905	39,773
Oregon	974,834	222,517,173	423,875	2,680,988	225,198,162	427,365
Washington	(41,951)	49,029,925	93,777	517,263	49,547,189	94,231
Eastern Wyoming	7,445	97,043,459	186,448	75,194	97,118,653	186,528
Utah	1,095,719	291,561,783	522,361	607,894	292,169,677	523,890
Idaho	24,471	58,185,112	98,339	96,162	58,281,274	98,441
Western Wyoming	(24,286)	20,752,712	36,112	(24,286)	20,728,425	36,070
Pre-merger Pacific	(9,135)	664,426	607	(9,135)	655,291	599
Pre-merger Utah	(27,040)	2,822,179	2,827	(27,040)	2,795,139	2,800
Post-merger	(583,447)	331,699,782	961,221	(559,425)	331,140,357	959,566
General Office	5,245,692	381,932,533	1,975,123	5,942,328	387,874,860	2,004,252
General Office	-	-	-	-	-	-
General Office	(67)	227,318	812	(67)	227,251	812
Customer Service	(106,932)	15,425,424	66,239	(106,932)	15,318,492	65,781
Fuel Related	(11,152)	3,316,406	9,918	(11,152)	3,305,254	9,884
Total General Plant	6,541,160	1,498,042,820	4,417,421	9,196,108	1,507,238,928	4,449,991
Mining Plant:						
Coal Mine	-	1,822,901	-	-	1,822,901	-
Total Mining Plant	-	1,822,901	-	-	1,822,901	-
Total Depreciation Expense	102,428,970	31,793,513,385	89,103,148	112,700,802	31,906,214,186	89,408,112

PacifiCorp
Oregon General Rate Case - December 2025
Jun 2023 - Dec 2024 Depreciation & Amortization Expense

Description	Factor	2018 Rate	Adjusted EPIS Balance Jun 2023	Depreciation Expense Jun 2023	Adjustments	Adjusted EPIS Balance Jul 2023	Depreciation Expense Jul 2023	Adjustments	Adjusted EPIS Balance Aug 2023	Depreciation Expense Aug 2023	Adjustments	Adjusted EPIS Balance Sep 2023	Depreciation Expense Sep 2023	Adjustments	Adjusted EPIS Balance Oct 2023	Depreciation Expense Oct 2023
AMORTIZATION EXPENSE																
Intangible Plant:																
California	CA	0.000%	472,341	-	(10)	472,331	-	(10)	472,322	-	(10)	472,312	-	(10)	472,302	-
Customer Service	CN	6.792%	231,939,839	1,312,777	(137,002)	231,802,837	1,312,390	(137,002)	231,665,836	1,311,614	(137,002)	231,528,834	1,310,839	(137,002)	231,391,833	1,310,063
Pre-merger Utah	SG	2.611%	477,596	1,039	(2,057)	475,540	1,037	(2,057)	473,483	1,032	(2,057)	471,427	1,028	(2,057)	469,370	1,024
Pre-merger Pacific	SG	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Idaho	ID	0.000%	4,356,591	-	(29)	4,356,562	-	(29)	4,356,533	-	(29)	4,356,505	-	(29)	4,356,476	-
Oregon	OR	0.243%	4,613,651	936	(402)	4,613,249	936	(402)	4,612,846	936	(402)	4,612,444	936	(402)	4,612,041	936
Fuel Related	SE	20.000%	9,106	152	(244)	8,862	150	(244)	8,617	146	(244)	8,373	142	(244)	8,129	138
Post-merger	SG	2.847%	207,905,089	493,211	(50,641)	207,854,448	493,151	(50,641)	207,803,807	493,031	(50,641)	207,753,166	492,911	(50,641)	207,702,525	492,790
Hydro Relicensing	SG-P	2.593%	103,455,075	223,559	(4,666)	103,450,409	223,554	(4,666)	103,445,744	223,544	(4,666)	103,441,078	223,534	(4,666)	103,436,412	223,524
Hydro Relicensing	SG-U	3.225%	10,024,217	26,941	(14,920)	10,009,296	26,921	(14,920)	9,994,376	26,881	(14,920)	9,979,455	26,840	(14,920)	9,964,535	26,800
General Office	SO	7.288%	485,192,721	2,946,873	(334,621)	484,858,100	2,945,857	6,203,646	491,061,747	2,963,680	3,174,464	494,236,211	2,992,160	2,291,328	496,527,539	3,008,758
Utah	UT	1.297%	7,525,664	8,137	(301)	7,525,362	8,137	(301)	7,525,061	8,136	(301)	7,524,759	8,136	(301)	7,524,458	8,136
Washington	WA	0.006%	2,021,868	10	-	2,021,868	10	-	2,021,868	10	-	2,021,868	10	-	2,021,868	10
Eastern Wyoming	WYP	1.275%	5,349,853	5,683	(2,628)	5,347,225	5,682	(2,628)	5,344,598	5,679	(2,628)	5,341,970	5,676	(2,628)	5,339,342	5,674
Western Wyoming	WYU	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Klamath		0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Intangible Plant			1,063,343,611	5,019,319	(547,520)	1,062,796,091	5,017,824	5,990,747	1,068,786,838	5,034,690	2,961,565	1,071,748,403	5,062,212	2,078,429	1,073,826,831	5,077,853
Hydro Production Plant:																
Pre-merger Pacific	SG	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG-P	2.125%	14,768,097	26,156	-	14,768,097	26,156	-	14,768,097	26,156	-	14,768,097	26,156	-	14,768,097	26,156
Post-merger	SG-U	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Hydro Plant			14,768,097	26,156	-	14,768,097	26,156	-	14,768,097	26,156	-	14,768,097	26,156	-	14,768,097	26,156
Other Production Plant:																
Oregon Solar	OR	13.675%	516,566	5,887	-	516,566	5,887	-	516,566	5,887	-	516,566	5,887	-	516,566	5,887
Total Other Plant			516,566	5,887	-	516,566	5,887	-	516,566	5,887	-	516,566	5,887	-	516,566	5,887
General Plant:																
California	CA	0.053%	505,860	22	-	505,860	22	-	505,860	22	-	505,860	22	-	505,860	22
General Office	CN	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Oregon	OR	2.456%	5,683,822	11,632	-	5,683,822	11,632	-	5,683,822	11,632	-	5,683,822	11,632	-	5,683,822	11,632
General Office	SO	1.883%	2,196,886	3,447	-	2,196,886	3,447	-	2,196,886	3,447	-	2,196,886	3,447	-	2,196,886	3,447
Utah	UT	0.000%	33,127	-	-	33,127	-	-	33,127	-	-	33,127	-	-	33,127	-
Washington	WA	4.191%	2,573,715	8,988	-	2,573,715	8,988	-	2,573,715	8,988	-	2,573,715	8,988	-	2,573,715	8,988
Eastern Wyoming	WYP	3.644%	4,752,256	14,430	-	4,752,256	14,430	-	4,752,256	14,430	-	4,752,256	14,430	-	4,752,256	14,430
Idaho	ID	0.000%	333,771	-	-	333,771	-	-	333,771	-	-	333,771	-	-	333,771	-
Total General Plant			16,079,436	38,520	-	16,079,436	38,520	-	16,079,436	38,520	-	16,079,436	38,520	-	16,079,436	38,520
Total Amortization			1,094,707,710	5,089,882	(547,520)	1,094,160,190	5,088,387	5,990,747	1,100,150,937	5,105,253	2,961,565	1,103,112,501	5,132,775	2,078,429	1,105,190,930	5,148,416
Total Depreciation & Amortization			32,665,268,227	93,795,088	55,573,833	32,720,842,060	93,846,741	70,393,291	32,791,235,351	93,978,394	105,390,535	32,896,625,886	94,235,923	114,779,230	33,011,405,116	94,556,528

PacifiCorp
Oregon General Rate Case - December 2025
Jun 2023 - Dec 2024 Depreciation & Amortization Expense

Description	Factor	2018 Rate	Adjustments	Adjusted EPIS Balance Nov 2023	Depreciation Expense Nov 2023	Adjustments	Adjusted EPIS Balance Dec 2023	Depreciation Expense Dec 2023	Adjustments	Adjusted EPIS Balance Jan 2024	Depreciation Expense Jan 2024	Adjustments	Adjusted EPIS Balance Feb 2024	Depreciation Expense Feb 2024	Adjustments	Adjusted EPIS Balance Mar 2024
DEPRECIATION EXPENSE																
Steam Production Plant:																
Pre-merger Pacific	SG	5.094%	(278,562)	1,007,310,418	4,276,697	(278,562)	1,007,031,857	4,275,514	(278,562)	1,006,753,295	4,274,332	(278,562)	1,006,474,734	4,273,149	(278,562)	1,006,196,172
Pre-merger Utah	SG	5.005%	(244,912)	1,050,535,908	4,381,884	(244,912)	1,050,290,997	4,380,863	(244,912)	1,050,046,085	4,379,841	(244,912)	1,049,801,173	4,378,820	(244,912)	1,049,556,262
Post-merger	SG	6.327%	7,478,572	4,971,919,969	26,196,300	15,026,973	4,986,946,942	26,255,634	(2,230,875)	4,984,716,067	26,289,370	(2,083,525)	4,982,632,541	26,277,995	3,002,466	4,985,635,007
Geothermal - Blundell	SG	6.327%	-	30,046,813	158,431	51,400	30,098,213	158,567	13,354	30,111,567	158,738	13,354	30,124,921	158,808	13,354	30,138,275
Carbon	SG	6.327%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pollution Control Equipment	SG	6.327%	119,106	287,979	1,204	514,019	801,998	2,874	-	801,998	4,229	-	801,998	4,229	-	801,998
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			7,074,205	7,061,367,939	35,014,517	15,068,919	7,076,436,858	35,073,452	(2,740,994)	7,073,695,864	35,106,509	(2,593,644)	7,071,102,219	35,093,001	2,492,346	7,073,594,566
Hydro Production Plant:																
Pre-merger Pacific	SG	2.208%	(39,742)	183,527,190	337,787	(39,742)	183,487,448	337,714	(39,742)	183,447,706	337,641	(39,742)	183,407,965	337,568	(39,742)	183,368,223
Pre-merger Utah	SG	3.187%	(33,680)	39,432,168	104,773	(33,680)	39,398,488	104,684	(33,680)	39,364,808	104,594	(33,680)	39,331,127	104,505	(33,680)	39,297,447
Post-merger	SG-P	2.767%	2,261,625	674,985,696	1,553,732	14,668,820	689,654,516	1,573,250	(297,009)	689,357,507	1,589,819	(297,009)	689,060,498	1,589,134	37,189,219	726,249,717
Post-merger	SG-U	4.631%	404,827	166,154,572	640,471	4,885,467	171,040,040	650,680	(131,663)	170,908,376	659,853	(131,663)	170,776,713	659,345	(53,083)	170,723,630
Klamath - New Capital	SG-P	20.000%	1,412,738	1,412,738	11,773	-	1,412,738	23,546	-	1,412,738	23,546	-	1,412,738	23,546	-	1,412,738
Future Use	Future Use		-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Hydro Plant			4,005,768	1,065,512,365	2,648,536	19,480,865	1,084,993,230	2,689,874	(502,094)	1,084,491,135	2,715,453	(502,094)	1,083,989,041	2,714,098	37,062,714	1,121,051,755
Other Production Plant:																
Pre-merger Utah	SG	0.000%	-	235,129	-	-	235,129	-	-	235,129	-	-	235,129	-	-	235,129
Post-merger	SG	3.505%	(692,174)	1,972,832,356	5,762,934	4,305,532	1,977,137,888	5,768,210	(1,971,169)	1,975,166,719	5,771,619	(1,971,169)	1,973,195,550	5,765,862	(1,971,169)	1,971,224,381
Post-merger Wind	SG-W	4.208%	81,130,361	3,311,078,264	11,469,392	5,036,477	3,316,114,741	11,620,481	1,356,051	3,317,470,792	11,631,690	947,725	3,318,418,517	11,635,730	3,878,245	3,322,296,762
Oregon Solar	OR	13.675%	-	328,709	3,746	20,958	349,667	3,865	-	349,667	3,985	-	349,667	3,985	-	349,667
Post-merger	SG	4.832%	167,110	88,862,973	357,477	(14,022)	88,848,951	357,785	(61,595)	88,787,357	357,633	(61,595)	88,725,762	357,385	(61,595)	88,664,167
Total Other Plant			80,605,297	5,373,337,431	17,593,549	9,348,945	5,382,686,376	17,750,342	(676,712)	5,382,009,664	17,764,928	(1,085,038)	5,380,924,625	17,762,962	1,845,482	5,382,770,107
Transmission Plant:																
Pre-merger Pacific	SG	1.699%	(188,188)	473,714,022	670,762	(188,188)	473,525,833	670,496	(188,188)	473,337,645	670,229	(188,188)	473,149,457	669,963	(188,188)	472,961,269
Pre-merger Utah	SG	1.672%	(348,507)	609,763,811	849,775	(348,507)	609,415,304	849,290	(348,507)	609,066,798	848,804	(348,507)	608,718,291	848,319	(348,507)	608,369,784
Post-merger	SG	1.725%	33,841,212	7,108,522,884	10,193,237	69,547,833	7,178,070,717	10,267,541	9,905,784	7,187,976,501	10,324,643	60,203,410	7,248,179,911	10,375,029	13,530,942	7,261,710,853
Total Transmission Plant			33,304,518	8,192,000,716	11,713,774	69,011,138	8,261,011,854	11,787,326	9,369,089	8,270,380,944	11,843,676	59,666,715	8,330,047,659	11,893,310	12,994,247	8,343,041,906
Distribution Plant:																
California	CA	2.710%	8,323,170	430,108,104	961,915	5,704,038	435,812,141	977,753	511,213	436,323,354	984,771	739,439	437,062,793	986,184	2,831,396	439,894,188
Oregon	OR	2.276%	4,379,839	2,631,824,160	4,987,029	11,274,959	2,643,099,119	5,001,874	1,060,001	2,644,159,119	5,013,570	3,708,514	2,647,867,634	5,018,092	7,593,798	2,655,461,431
Washington	WA	2.581%	177,240	633,379,043	1,362,003	293,930	633,672,972	1,362,510	626,104	634,299,077	1,363,499	679,703	634,978,779	1,364,903	2,177,285	637,156,065
Eastern Wyoming	WYP	2.657%	1,446,297	749,066,229	1,656,779	1,434,489	750,500,718	1,659,968	969,927	751,470,645	1,662,629	1,125,138	752,595,783	1,664,948	1,441,243	754,037,026
Utah	UT	2.548%	28,644,597	3,834,883,019	8,112,656	70,396,169	3,905,279,188	8,217,809	12,331,437	3,917,610,625	8,305,642	17,029,283	3,934,639,907	8,336,814	17,390,023	3,952,029,930
Idaho	ID	2.540%	1,038,011	441,774,428	934,009	992,094	442,766,522	936,157	807,009	443,573,532	938,062	859,641	444,433,173	939,825	1,269,799	445,702,972
Western Wyoming	WYU	2.654%	(45,586)	152,852,280	338,151	(45,586)	152,806,694	338,050	(45,586)	152,761,108	337,949	(45,586)	152,715,522	337,848	(45,586)	152,669,936
Total Distribution Plant			43,963,567	8,873,887,262	18,352,542	90,050,091	8,963,937,353	18,494,121	16,260,106	8,980,197,459	18,606,122	24,096,132	9,004,293,591	18,648,615	32,657,958	9,036,951,549
General Plant:																
California	CA	2.087%	(10,976)	22,867,929	39,776	16,103	22,884,033	39,780	(49,439)	22,834,594	39,751	(50,874)	22,783,720	39,664	(47,171)	22,736,549
Oregon	OR	2.291%	2,212,099	227,410,261	432,035	3,144,481	230,554,742	437,148	(413,237)	230,141,505	439,755	(442,985)	229,698,521	438,938	(375,754)	229,322,767
Washington	WA	2.294%	491,970	50,039,159	95,196	519,049	50,558,208	96,162	(86,760)	50,471,449	96,575	(90,548)	50,380,901	96,406	558,013	50,938,915
Eastern Wyoming	WYP	2.306%	4,012,811	101,131,464	190,455	340,803	101,472,267	194,637	181,796	101,654,064	195,139	43,809	101,697,872	195,356	64,040	101,761,912
Utah	UT	2.154%	636,300	292,805,977	525,007	3,996,550	296,802,526	529,165	1,129,174	297,931,700	533,765	176,650	298,108,350	534,937	301,705	298,410,055
Idaho	ID	2.029%	96,235	58,377,509	98,604	421,438	58,798,947	99,041	190,978	58,989,924	99,559	53,964	59,043,888	99,766	72,365	59,116,253
Western Wyoming	WYU	2.087%	(24,286)	20,704,139	36,027	(24,286)	20,679,853	35,985	(24,286)	20,655,567	35,943	(24,286)	20,631,281	35,901	(24,286)	20,606,994
Pre-merger Pacific	SG	1.090%	(9,135)	646,155	591	(9,135)	637,020	583	(9,135)	627,884	574	(9,135)	618,749	566	(9,135)	609,614
Pre-merger Utah	SG	1.196%	(27,040)	2,768,099	2,773	(27,040)	2,741,058	2,746	(27,040)	2,714,018	2,719	(27,040)	2,686,978	2,692	(27,040)	2,659,938
Post-merger	SG	3.474%	(5,266)	331,135,091	958,749	(226,328)	330,908,763	958,414	(603,907)	330,304,856	957,212	(603,907)	329,700,949	955,463	(603,907)	329,097,043
General Office	SO	6.249%	2,717,382	390,592,242	2,026,798	6,663,565	397,255,807	2,051,222	1,641,357	398,897,163	2,072,845	2,682,034	401,579,197	2,084,101	2,113,707	403,692,904
General Office	SG	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
General Office	SG	4.285%	(67)	227,183	811	(67)	227,116	811	(67)	227,049	811	(67)	226,981	811	(67)	226,914
Customer Service	CN	5.135%	(106,932)	15,211,560	65,324	(106,932)	15,104,628	64,866	(106,932)	14,997,696	64,408	(106,932)	14,890,764	63,951	(106,932)	14,783,832
Fuel Related	SE	3.583%	(11,152)	3,294,102	9,851	(11,152)	3,282,950	9,818	(11,152)	3,271,799	9,784	(11,152)	3,260,647	9,751	(11,152)	3,249,495
Total General Plant			9,971,942	1,517,210,871	4,481,996	14,697,048	1,531,907,919	4,520,378	1,811,349	1,533,719,268	4,548,841	1,589,531	1,535,308,799	4,558,302	1,904,385	1,537,213,184
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			178,925,298	32,085,139,484	89,804,914	217,657,007	32,302,796,491	90,315,493	23,520,743	32,326,317,235	90,585,530	81,171,600	32,407,488,835	90,670,289	88,957,132	32,496,445,967

PacifiCorp
Oregon General Rate Case - December 2025
Jun 2023 - Dec 2024 Depreciation & Amortization Expense

Description	Factor	2018 Rate	Adjustments	Adjusted EPIS Balance Nov 2023	Depreciation Expense Nov 2023	Adjustments	Adjusted EPIS Balance Dec 2023	Depreciation Expense Dec 2023	Adjustments	Adjusted EPIS Balance Jan 2024	Depreciation Expense Jan 2024	Adjustments	Adjusted EPIS Balance Feb 2024	Depreciation Expense Feb 2024	Adjustments	Adjusted EPIS Balance Mar 2024
AMORTIZATION EXPENSE																
Intangible Plant:																
California	CA	0.000%	(10)	472,293	-	(10)	472,283	-	(10)	472,273	-	(10)	472,264	-	(10)	472,254
Customer Service	CN	6.792%	(137,002)	231,254,831	1,309,288	(137,002)	231,117,829	1,308,512	(137,002)	230,980,828	1,307,737	(137,002)	230,843,826	1,306,962	(137,002)	230,706,825
Pre-merger Utah	SG	2.611%	(2,057)	467,313	1,019	(2,057)	465,257	1,015	(2,057)	463,200	1,010	(2,057)	461,143	1,006	(2,057)	459,087
Pre-merger Pacific	SG	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Idaho	ID	0.000%	(29)	4,356,447	-	(29)	4,356,418	-	(29)	4,356,389	-	(29)	4,356,361	-	(29)	4,356,332
Oregon	OR	0.243%	(402)	4,611,639	936	(402)	4,611,237	936	(402)	4,610,834	936	(402)	4,610,432	936	(402)	4,610,029
Fuel Related	SE	20.000%	(244)	7,885	133	(244)	7,640	129	(244)	7,396	125	(244)	7,152	121	(244)	6,908
Post-merger	SG	2.847%	(50,641)	207,651,884	492,670	(50,641)	207,601,243	492,550	(50,641)	207,550,602	492,430	(50,641)	207,499,961	492,310	(50,641)	207,449,320
Hydro Relicensing	SG-P	2.593%	(4,666)	103,431,747	223,514	(4,666)	103,427,081	223,504	(4,666)	103,422,416	223,494	(4,666)	103,417,750	223,483	(4,666)	103,413,085
Hydro Relicensing	SG-U	3.225%	(14,920)	9,949,615	26,760	(14,920)	9,934,694	26,720	(14,920)	9,919,774	26,680	(14,920)	9,904,853	26,640	(14,920)	9,889,933
General Office	SO	7.288%	(83,296)	496,444,244	3,015,464	2,640,899	499,085,143	3,023,231	(558,300)	498,526,843	3,029,555	(130,177)	498,396,666	3,027,464	3,473,585	501,870,250
Utah	UT	1.297%	(301)	7,524,157	8,135	(301)	7,523,855	8,135	(301)	7,523,554	8,135	(301)	7,523,252	8,134	(301)	7,522,951
Washington	WA	0.006%	-	2,021,868	10	-	2,021,868	10	-	2,021,868	10	-	2,021,868	10	-	2,021,868
Eastern Wyoming	WYP	1.275%	(2,628)	5,336,714	5,671	(2,628)	5,334,087	5,668	(2,628)	5,331,459	5,665	(2,628)	5,328,831	5,662	(2,628)	5,326,204
Western Wyoming	WYU	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Klamath		0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Intangible Plant			(296,195)	1,073,530,636	5,083,601	2,428,000	1,075,958,636	5,090,410	(771,200)	1,075,187,436	5,095,777	(343,077)	1,074,844,360	5,092,729	3,260,685	1,078,105,045
Hydro Production Plant:																
Pre-merger Pacific	SG	0.000%	-	-	-	-		-	-	-	-	-	-	-	-	-
Post-merger	SG-P	2.125%	-	14,768,097	26,156	-	14,768,097	26,156	-	14,768,097	26,156	-	14,768,097	26,156	-	14,768,097
Post-merger	SG-U	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Hydro Plant			-	14,768,097	26,156	-	14,768,097	26,156	-	14,768,097	26,156	-	14,768,097	26,156	-	14,768,097
Other Production Plant:																
Oregon Solar	OR	13.675%	-	516,566	5,887	-	516,566	5,887	-	516,566	5,887	-	516,566	5,887	-	516,566
Total Other Plant			-	516,566	5,887	-	516,566	5,887	-	516,566	5,887	-	516,566	5,887	-	516,566
General Plant:																
California	CA	0.053%	-	505,860	22	-	505,860	22	-	505,860	22	-	505,860	22	-	505,860
General Office	CN	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Oregon	OR	2.456%	-	5,683,822	11,632	-	5,683,822	11,632	-	5,683,822	11,632	-	5,683,822	11,632	-	5,683,822
General Office	SO	1.883%	-	2,196,886	3,447	-	2,196,886	3,447	-	2,196,886	3,447	-	2,196,886	3,447	-	2,196,886
Utah	UT	0.000%	-	33,127	-	-	33,127	-	-	33,127	-	-	33,127	-	-	33,127
Washington	WA	4.191%	-	2,573,715	8,988	-	2,573,715	8,988	-	2,573,715	8,988	-	2,573,715	8,988	-	2,573,715
Eastern Wyoming	WYP	3.644%	-	4,752,256	14,430	-	4,752,256	14,430	-	4,752,256	14,430	-	4,752,256	14,430	-	4,752,256
Idaho	ID	0.000%	-	333,771	-	-	333,771	-	-	333,771	-	-	333,771	-	-	333,771
Total General Plant			-	16,079,436	38,520	-	16,079,436	38,520	-	16,079,436	38,520	-	16,079,436	38,520	-	16,079,436
Total Amortization			(296,195)	1,104,894,735	5,154,164	2,428,000	1,107,322,735	5,160,973	(771,200)	1,106,551,535	5,166,340	(343,077)	1,106,208,458	5,163,292	3,260,685	1,109,469,144
Total Depreciation & Amortization			178,629,103	33,190,034,219	94,959,077	220,085,007	33,410,119,226	95,476,466	22,749,544	33,432,868,770	95,751,870	80,828,524	33,513,697,294	95,833,580	92,217,817	33,605,915,110

PacifiCorp
Oregon General Rate Case - December 2025
Jun 2023 - Dec 2024 Depreciation & Amortization Expense

Description	Factor	2018 Rate	Depreciation Expense Mar 2024	Adjustments	Adjusted EPIS Balance Apr 2024	Depreciation Expense Apr 2024	Adjustments	Adjusted EPIS Balance May 2024	Depreciation Expense May 2024	Adjustments	Adjusted EPIS Balance Jun 2024	Depreciation Expense Jun 2024	Adjustments	Adjusted EPIS Balance Jul 2024	Depreciation Expense Jul 2024	Adjustments
DEPRECIATION EXPENSE																
Steam Production Plant:																
Pre-merger Pacific	SG	5.094%	4,271,967	(278,562)	1,005,917,611	4,270,784	(278,562)	1,005,639,049	4,269,602	(278,562)	1,005,360,487	4,268,419	(278,562)	1,005,081,926	4,267,237	(278,562)
Pre-merger Utah	SG	5.005%	4,377,799	(244,912)	1,049,311,350	4,376,777	(244,912)	1,049,066,438	4,375,756	(244,912)	1,048,821,527	4,374,734	(244,912)	1,048,576,615	4,373,713	(244,912)
Post-merger	SG	6.327%	26,280,418	56,325,468	5,041,960,475	26,436,831	(1,586,108)	5,040,374,367	26,581,146	3,978,143	5,044,352,510	26,587,452	(1,758,420)	5,042,594,090	26,593,304	(751,248)
Geothermal - Blundell	SG	6.327%	158,878	13,354	30,151,629	158,949	13,354	30,164,983	159,019	116,434	30,281,417	159,361	13,354	30,294,772	159,704	13,354
Carbon	SG	6.327%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pollution Control Equipment	SG	6.327%	4,229	-	801,998	4,229	-	801,998	4,229	135,306	937,305	4,586	330,484	1,267,789	5,814	-
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			35,093,290	55,815,349	7,129,409,915	35,247,569	(2,096,227)	7,127,313,687	35,389,751	3,706,410	7,131,020,097	35,394,553	(1,938,055)	7,129,082,043	35,399,771	(1,261,367)
Hydro Production Plant:																
Pre-merger Pacific	SG	2.208%	337,495	(39,742)	183,328,481	337,422	(39,742)	183,288,739	337,348	(39,742)	183,248,998	337,275	(39,742)	183,209,256	337,202	(39,742)
Pre-merger Utah	SG	3.187%	104,415	(33,680)	39,263,767	104,326	(33,680)	39,230,087	104,236	(33,680)	39,196,406	104,147	(33,680)	39,162,726	104,057	(33,680)
Post-merger	SG-P	2.767%	1,631,666	(297,009)	725,952,708	1,674,198	(297,009)	725,655,699	1,673,513	(191,627)	725,464,072	1,672,950	436,744	725,900,817	1,673,232	(297,009)
Post-merger	SG-U	4.631%	658,989	(131,663)	170,591,967	658,632	259,023	170,850,990	658,878	2,688,458	173,539,447	664,566	2,271,478	175,810,926	674,137	(131,663)
Klamath - New Capital	SG-P	20.000%	23,546	-	1,412,738	23,546	-	1,412,738	23,546	-	1,412,738	23,546	-	1,412,738	23,546	-
Future Use	Future Use		-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Hydro Plant			2,756,110	(502,094)	1,120,549,661	2,798,123	(111,408)	1,120,438,253	2,797,522	2,423,409	1,122,861,662	2,802,483	2,634,801	1,125,496,462	2,812,174	(502,094)
Other Production Plant:																
Pre-merger Utah	SG	0.000%	-	-	235,129	-	-	235,129	-	-	235,129	-	-	235,129	-	-
Post-merger	SG	3.505%	5,760,105	(1,971,169)	1,969,253,212	5,754,348	(1,124,017)	1,968,129,196	5,749,828	263,297	1,968,392,493	5,748,571	(1,971,169)	1,966,421,324	5,746,077	(1,971,169)
Post-merger Wind	SG-W	4.208%	11,644,192	1,130,925	3,323,427,687	11,652,975	1,014,258	3,324,441,946	11,656,737	4,195,027	3,328,636,972	11,665,871	697,725	3,329,334,698	11,674,450	687,725
Oregon Solar	OR	13.675%	3,985	-	349,667	3,985	-	349,667	3,985	-	349,667	3,985	-	349,667	3,985	-
Post-merger	SG	4.832%	357,137	(61,595)	88,602,572	356,889	3,853	88,606,426	356,773	(24,661)	88,581,765	356,731	126,436	88,708,201	356,936	(61,595)
Total Other Plant			17,765,419	(901,838)	5,381,868,269	17,768,197	(105,905)	5,381,762,363	17,767,323	4,433,663	5,386,196,027	17,775,158	(1,147,007)	5,385,049,019	17,781,448	(1,345,038)
Transmission Plant:																
Pre-merger Pacific	SG	1.699%	669,696	(188,188)	472,773,081	669,430	(188,188)	472,584,892	669,163	(188,188)	472,396,704	668,897	(188,188)	472,208,516	668,631	(188,188)
Pre-merger Utah	SG	1.672%	847,833	(348,507)	608,021,278	847,348	(348,507)	607,672,771	846,862	(348,507)	607,324,265	846,376	(348,507)	606,975,758	845,891	(348,507)
Post-merger	SG	1.725%	10,428,021	18,762,163	7,280,473,015	10,451,229	142,683,415	7,423,156,431	10,567,257	31,020,807	7,454,177,238	10,692,096	69,526,327	7,523,703,565	10,764,357	69,429,246
Total Transmission Plant			11,945,550	18,225,468	8,361,267,374	11,968,007	142,146,720	8,503,414,094	12,083,283	30,484,112	8,533,898,207	12,207,369	68,989,632	8,602,887,839	12,278,879	68,892,552
Distribution Plant:																
California	CA	2.710%	990,216	776,494	440,670,683	994,289	4,356,034	445,026,717	1,000,085	5,017,977	450,044,695	1,010,669	3,905,412	453,950,107	1,020,745	526,352
Oregon	OR	2.276%	5,028,809	4,345,219	2,659,806,651	5,040,130	5,781,044	2,665,587,695	5,049,732	6,483,943	2,672,071,638	5,061,363	9,970,359	2,682,041,997	5,076,965	4,629,592
Washington	WA	2.581%	1,367,975	1,667,076	638,823,141	1,372,109	2,490,234	641,313,375	1,376,580	1,367,478	642,680,854	1,380,728	1,808,591	644,489,445	1,384,144	1,425,993
Eastern Wyoming	WYP	2.657%	1,667,789	1,463,120	755,500,145	1,671,004	1,489,700	756,989,845	1,674,273	1,863,311	758,853,156	1,677,985	1,548,851	760,402,007	1,681,762	1,774,382
Utah	UT	2.548%	8,373,357	20,501,338	3,972,531,268	8,413,587	37,800,426	4,010,331,693	8,475,487	22,521,328	4,032,853,021	8,539,531	20,317,622	4,053,170,643	8,585,013	23,825,924
Idaho	ID	2.540%	942,079	1,292,626	446,995,597	944,791	11,385,630	458,381,228	958,209	1,362,940	459,744,168	971,702	1,213,416	460,957,584	974,428	1,428,792
Western Wyoming	WYU	2.654%	337,747	(45,586)	152,624,351	337,647	(45,586)	152,578,765	337,546	(45,586)	152,533,179	337,445	(45,586)	152,487,593	337,344	(45,586)
Total Distribution Plant			18,707,974	30,000,287	9,066,951,836	18,773,558	63,257,483	9,130,209,319	18,871,912	38,571,392	9,168,780,711	18,979,422	38,718,666	9,207,499,377	19,060,402	33,565,448
General Plant:																
California	CA	2.087%	39,579	(51,713)	22,684,836	39,493	(42,523)	22,642,313	39,411	(36,340)	22,605,973	39,342	(17,682)	22,588,291	39,295	(39,324)
Oregon	OR	2.291%	438,157	(399,238)	228,923,529	437,417	(212,731)	228,710,797	436,833	(46,044)	228,664,754	436,586	294,848	228,959,602	436,823	(218,819)
Washington	WA	2.294%	96,853	(96,037)	50,842,877	97,294	(73,470)	50,769,407	97,132	(54)	50,769,353	97,062	(13,455)	50,755,898	97,049	(74,117)
Eastern Wyoming	WYP	2.306%	195,460	62,159	101,824,071	195,581	115,174	101,939,244	195,751	187,832	102,127,076	196,042	97,891	102,224,967	196,317	184,248
Utah	UT	2.154%	535,366	298,073	298,708,128	535,904	658,249	299,366,378	536,763	1,138,086	300,504,463	538,375	535,021	301,039,484	539,876	1,131,801
Idaho	ID	2.029%	99,873	71,180	59,187,433	99,994	122,614	59,310,046	100,158	192,392	59,502,438	100,424	105,534	59,607,972	100,676	191,220
Western Wyoming	WYU	2.087%	35,858	(24,286)	20,582,708	35,816	(24,286)	20,558,422	35,774	(24,286)	20,534,136	35,732	(24,286)	20,509,850	35,689	(24,286)
Pre-merger Pacific	SG	1.090%	558	(9,135)	600,478	549	(9,135)	591,343	541	(9,135)	582,207	533	(9,135)	573,072	525	(9,135)
Pre-merger Utah	SG	1.196%	2,666	(27,040)	2,632,898	2,639	(27,040)	2,605,858	2,612	(27,040)	2,578,818	2,585	(27,040)	2,551,777	2,558	(27,040)
Post-merger	SG	3.474%	953,715	(603,907)	328,493,136	951,966	(603,907)	327,889,229	950,218	(603,907)	327,285,322	948,469	(594,499)	326,690,823	946,734	(603,907)
General Office	SO	6.249%	2,096,587	1,697,017	405,389,921	2,106,508	2,860,507	408,250,427	2,118,374	5,937,972	414,188,399	2,141,282	2,687,589	416,875,988	2,163,739	1,956,075
General Office	SG	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
General Office	SG	4.285%	810	(67)	226,847	810	(67)	226,779	810	(67)	226,712	810	(67)	226,645	809	(67)
Customer Service	CN	5.135%	63,493	(106,932)	14,676,900	63,036	(106,932)	14,569,968	62,578	(106,932)	14,463,036	62,120	(106,932)	14,356,104	61,663	(106,932)
Fuel Related	SE	3.583%	9,718	(11,152)	3,238,343	9,685	(11,152)	3,227,191	9,651	(11,152)	3,216,039	9,618	(11,152)	3,204,887	9,585	(11,152)
Total General Plant			4,568,691	798,920	1,538,012,104	4,576,692	2,645,298	1,540,657,402	4,586,605	6,591,323	1,547,248,726	4,608,979	2,916,634	1,550,165,360	4,631,339	2,348,564
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			90,837,035	103,436,092	32,599,882,058	91,132,147	205,735,961	32,805,618,020	91,496,395	86,210,310	32,891,828,330	91,767,965	110,174,672	33,002,003,001	91,964,013	101,698,064

PacifiCorp
Oregon General Rate Case - December 2025
Jun 2023 - Dec 2024 Depreciation & Amortization Expense

Description	Factor	2018 Rate	Depreciation Expense Mar 2024	Adjustments	Adjusted EPIS Balance Apr 2024	Depreciation Expense Apr 2024	Adjustments	Adjusted EPIS Balance May 2024	Depreciation Expense May 2024	Adjustments	Adjusted EPIS Balance Jun 2024	Depreciation Expense Jun 2024	Adjustments	Adjusted EPIS Balance Jul 2024	Depreciation Expense Jul 2024	Adjustments
AMORTIZATION EXPENSE																
Intangible Plant:																
California	CA	0.000%	-	(10)	472,244	-	(10)	472,235	-	(10)	472,225	-	(10)	472,215	-	(10)
Customer Service	CN	6.792%	1,306,186	(137,002)	230,569,823	1,305,411	(137,002)	230,432,822	1,304,635	(137,002)	230,295,820	1,303,860	(137,002)	230,158,819	1,303,084	(137,002)
Pre-merger Utah	SG	2.611%	1,001	(2,057)	457,030	997	(2,057)	454,974	992	(2,057)	452,917	988	(2,057)	450,860	983	(2,057)
Pre-merger Pacific	SG	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Idaho	ID	0.000%	-	(29)	4,356,303	-	(29)	4,356,274	-	(29)	4,356,246	-	(29)	4,356,217	-	(29)
Oregon	OR	0.243%	935	(402)	4,609,627	935	(402)	4,609,224	935	(402)	4,608,822	935	(402)	4,608,419	935	(402)
Fuel Related	SE	20.000%	117	(244)	6,664	113	(244)	6,419	109	(244)	6,175	105	(244)	5,931	101	(244)
Post-merger	SG	2.847%	492,190	(50,641)	207,398,679	492,070	(50,641)	207,348,038	491,950	(50,641)	207,297,396	491,829	(50,641)	207,246,755	491,709	(50,641)
Hydro Relicensing	SG-P	2.593%	223,473	(4,666)	103,408,419	223,463	(4,666)	103,403,753	223,453	(4,666)	103,399,088	223,443	(4,666)	103,394,422	223,433	(4,666)
Hydro Relicensing	SG-U	3.225%	26,600	(14,920)	9,875,013	26,560	(14,920)	9,860,092	26,520	(14,920)	9,845,172	26,480	(14,920)	9,830,251	26,439	(14,920)
General Office	SO	7.288%	3,037,618	6,084,594	507,954,844	3,066,644	304,063	508,258,907	3,086,045	21,772,605	530,031,512	3,153,088	(436,500)	529,595,012	3,217,881	2,035,994
Utah	UT	1.297%	8,134	(301)	7,522,649	8,134	(301)	7,522,348	8,133	(301)	7,522,046	8,133	(301)	7,521,745	8,133	(301)
Washington	WA	0.006%	10	-	2,021,868	10	-	2,021,868	10	-	2,021,868	10	-	2,021,868	10	-
Eastern Wyoming	WYP	1.275%	5,660	(2,628)	5,323,576	5,657	(2,628)	5,320,948	5,654	(2,628)	5,318,321	5,651	(2,628)	5,315,693	5,648	(2,628)
Western Wyoming	WYU	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Klamath		0.000%		-	-		-	-		-	-		-	-		-
Total Intangible Plant			5,101,925	5,871,694	1,083,976,739	5,129,994	91,163	1,084,067,902	5,148,437	21,559,705	1,105,627,608	5,214,522	(649,400)	1,104,978,208	5,278,358	1,823,094
Hydro Production Plant:																
Pre-merger Pacific	SG	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG-P	2.125%	26,156	-	14,768,097	26,156	-	14,768,097	26,156	-	14,768,097	26,156	-	14,768,097	26,156	-
Post-merger	SG-U	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Hydro Plant			26,156	-	14,768,097	26,156	-	14,768,097	26,156	-	14,768,097	26,156	-	14,768,097	26,156	-
Other Production Plant:																
Oregon Solar	OR	13.675%	5,887	-	516,566	5,887	-	516,566	5,887	-	516,566	5,887	-	516,566	5,887	-
Total Other Plant			5,887	-	516,566	5,887	-	516,566	5,887	-	516,566	5,887	-	516,566	5,887	-
General Plant:																
California	CA	0.053%	22	-	505,860	22	-	505,860	22	-	505,860	22	-	505,860	22	-
General Office	CN	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Oregon	OR	2.456%	11,632	-	5,683,822	11,632	-	5,683,822	11,632	-	5,683,822	11,632	-	5,683,822	11,632	-
General Office	SO	1.883%	3,447	-	2,196,886	3,447	-	2,196,886	3,447	-	2,196,886	3,447	-	2,196,886	3,447	-
Utah	UT	0.000%	-	-	33,127	-	-	33,127	-	-	33,127	-	-	33,127	-	-
Washington	WA	4.191%	8,988	-	2,573,715	8,988	-	2,573,715	8,988	-	2,573,715	8,988	-	2,573,715	8,988	-
Eastern Wyoming	WYP	3.644%	14,430	-	4,752,256	14,430	-	4,752,256	14,430	-	4,752,256	14,430	-	4,752,256	14,430	-
Idaho	ID	0.000%	-	-	333,771	-	-	333,771	-	-	333,771	-	-	333,771	-	-
Total General Plant			38,520	-	16,079,436	38,520	-	16,079,436	38,520	-	16,079,436	38,520	-	16,079,436	38,520	-
Total Amortization			5,172,488	5,871,694	1,115,340,838	5,200,556	91,163	1,115,432,001	5,219,000	21,559,705	1,136,991,706	5,285,085	(649,400)	1,136,342,307	5,348,921	1,823,094
Total Depreciation & Amortization			96,009,522	109,307,786	33,715,222,896	96,332,703	205,827,125	33,921,050,021	96,715,395	107,770,015	34,028,820,036	97,053,050	109,525,272	34,138,345,308	97,312,934	103,521,158

PacifiCorp
Oregon General Rate Case - December 2025
Jun 2023 - Dec 2024 Depreciation & Amortization Expense

Description	Factor	2018 Rate	Adjusted EPIS Balance Aug 2024	Depreciation Expense Aug 2024	Adjustments	Adjusted EPIS Balance Sep 2024	Depreciation Expense Sep 2024	Adjustments	Adjusted EPIS Balance Oct 2024	Depreciation Expense Oct 2024	Adjustments	Adjusted EPIS Balance Nov 2024	Depreciation Expense Nov 2024	Adjustments	Adjusted EPIS Balance Dec 2024	Depreciation Expense Dec 2024
DEPRECIATION EXPENSE																
Steam Production Plant:																
Pre-merger Pacific	SG	5.094%	1,004,803,364	4,266,054	(278,562)	1,004,524,803	4,264,871	(278,562)	1,004,246,241	4,263,689	(278,562)	1,003,967,679	4,262,506	(278,562)	1,003,689,118	4,261,324
Pre-merger Utah	SG	5.005%	1,048,331,704	4,372,691	(244,912)	1,048,086,792	4,371,670	(244,912)	1,047,841,880	4,370,648	(244,912)	1,047,596,969	4,369,627	(244,912)	1,047,352,057	4,368,606
Post-merger	SG	6.327%	5,041,842,842	26,586,688	(2,360,755)	5,039,482,088	26,578,483	(1,798,872)	5,037,683,216	26,567,517	(610,448)	5,037,072,768	26,561,165	11,148,954	5,048,221,722	26,588,949
Geothermal - Blundell	SG	6.327%	30,308,126	159,774	13,354	30,321,480	159,844	13,354	30,334,834	159,915	13,354	30,348,188	159,985	13,354	30,361,542	160,056
Carbon	SG	6.327%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pollution Control Equipment	SG	6.327%	1,267,789	6,685	-	1,267,789	6,685	-	1,267,789	6,685	-	1,267,789	6,685	68,738	1,336,526	6,866
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			7,127,820,676	35,391,892	(2,870,874)	7,124,949,802	35,381,554	(2,308,991)	7,122,640,811	35,368,454	(1,120,567)	7,121,520,244	35,359,969	10,707,572	7,132,227,816	35,385,800
Hydro Production Plant:																
Pre-merger Pacific	SG	2.208%	183,169,514	337,129	(39,742)	183,129,773	337,056	(39,742)	183,090,031	336,983	(39,742)	183,050,289	336,910	(39,742)	183,010,548	336,837
Pre-merger Utah	SG	3.187%	39,129,046	103,968	(33,680)	39,095,365	103,879	(33,680)	39,061,685	103,789	(33,680)	39,028,005	103,700	(33,680)	38,994,324	103,610
Post-merger	SG-P	2.767%	725,603,807	1,673,393	11,714,345	737,318,153	1,686,556	15,334,756	752,652,909	1,717,740	3,084,024	755,736,933	1,738,975	6,972,570	762,709,502	1,750,569
Post-merger	SG-U	4.631%	175,679,262	678,266	(131,663)	175,547,599	677,758	(131,663)	175,415,936	677,250	13,565,981	188,981,917	703,174	7,185,223	196,167,141	743,217
Klamath - New Capital	SG-P	20.000%	1,412,738	23,546	-	1,412,738	23,546	-	1,412,738	23,546	-	1,412,738	23,546	-	1,412,738	23,546
Future Use	Future Use		-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Hydro Plant			1,124,994,368	2,816,302	11,509,260	1,136,503,628	2,828,794	15,129,671	1,151,633,299	2,859,307	16,576,584	1,168,209,882	2,906,303	14,084,371	1,182,294,253	2,957,778
Other Production Plant:																
Pre-merger Utah	SG	0.000%	235,129	-	-	235,129	-	-	235,129	-	-	235,129	-	-	235,129	-
Post-merger	SG	3.505%	1,964,450,155	5,740,320	(1,971,169)	1,962,478,986	5,734,563	(1,971,169)	1,960,507,818	5,728,806	(1,971,169)	1,958,536,649	5,723,049	313	1,958,536,962	5,720,171
Post-merger Wind	SG-W	4.208%	3,330,022,423	11,676,880	3,618,577	3,333,640,999	11,684,431	749,263	3,334,390,262	11,692,089	749,263	3,335,139,525	11,694,717	4,966,979	3,340,106,504	11,704,740
Oregon Solar	OR	13.675%	349,667	3,985	-	349,667	3,985	-	349,667	3,985	-	349,667	3,985	99,127	448,794	4,550
Post-merger	SG	4.832%	88,646,607	357,066	(61,595)	88,585,012	356,818	(61,595)	88,523,417	356,570	(61,595)	88,461,823	356,322	(61,595)	88,400,228	356,074
Total Other Plant			5,383,703,981	17,778,251	1,585,813	5,385,289,794	17,779,797	(1,283,501)	5,384,006,294	17,781,450	(1,283,501)	5,382,722,793	17,778,073	5,004,824	5,387,727,617	17,785,535
Transmission Plant:																
Pre-merger Pacific	SG	1.699%	472,020,328	668,364	(188,188)	471,832,140	668,098	(188,188)	471,643,951	667,831	(188,188)	471,455,763	667,565	(188,188)	471,267,575	667,299
Pre-merger Utah	SG	1.672%	606,627,252	845,405	(348,507)	606,278,745	844,920	(348,507)	605,930,239	844,434	(348,507)	605,581,732	843,949	(348,507)	605,233,226	843,463
Post-merger	SG	1.725%	7,593,132,811	10,864,222	184,357,487	7,777,490,298	11,046,615	53,443,540	7,830,933,838	11,217,519	2,317,596,068	10,148,529,906	12,921,546	33,637,282	10,182,167,188	14,611,339
Total Transmission Plant			8,671,780,391	12,377,992	183,820,792	8,855,601,183	12,559,632	52,906,846	8,908,508,028	12,729,784	2,317,059,373	11,225,567,402	14,433,060	33,100,587	11,258,667,989	16,122,100
Distribution Plant:																
California	CA	2.710%	454,476,459	1,025,749	382,782	454,859,241	1,026,776	1,540,302	456,399,543	1,028,947	1,266,435	457,665,978	1,032,117	118,685,821	576,351,800	1,167,561
Oregon	OR	2.276%	2,686,671,589	5,090,809	3,000,850	2,689,672,439	5,098,045	1,858,010	2,691,530,449	5,102,652	10,979,976	2,702,510,425	5,114,826	2,978,626	2,705,489,051	5,128,062
Washington	WA	2.581%	645,915,438	1,387,622	827,265	646,742,704	1,390,045	655,069	647,397,772	1,391,639	3,266,038	650,663,810	1,395,855	11,897,970	662,561,779	1,412,162
Eastern Wyoming	WYP	2.657%	762,176,389	1,685,441	1,751,028	763,927,418	1,689,343	1,379,097	765,306,515	1,692,808	1,266,939	766,573,453	1,695,737	9,097,750	775,671,204	1,707,210
Utah	UT	2.548%	4,076,996,567	8,631,881	39,561,895	4,116,558,461	8,699,181	16,704,271	4,133,262,733	8,758,919	23,499,201	4,156,761,934	8,801,603	49,303,824	4,206,065,758	8,878,899
Idaho	ID	2.540%	462,386,376	977,225	3,631,657	466,018,034	982,581	1,193,663	467,211,697	987,687	1,085,837	468,297,534	990,100	1,042,352	469,339,885	992,352
Western Wyoming	WYU	2.654%	152,442,007	337,243	(45,586)	152,396,421	337,142	(45,586)	152,350,836	337,042	(45,586)	152,305,250	336,941	(45,586)	152,259,664	336,840
Total Distribution Plant			9,241,064,826	19,135,970	49,109,893	9,290,174,718	19,223,112	23,284,826	9,313,459,544	19,299,694	41,318,840	9,354,778,384	19,367,179	192,960,757	9,547,739,141	19,623,086
General Plant:																
California	CA	2.087%	22,548,966	39,246	(23,161)	22,525,806	39,191	(11,199)	22,514,606	39,161	(30,144)	22,484,462	39,125	1,411,077	23,895,539	40,326
Oregon	OR	2.291%	228,740,783	436,896	231,238	228,972,021	436,908	491,472	229,463,493	437,597	17,932	229,481,425	438,084	50,939,168	280,420,593	486,725
Washington	WA	2.294%	50,681,781	96,965	(23,479)	50,658,302	96,872	368	50,658,670	96,850	(48,882)	50,609,788	96,804	2,839,694	53,449,482	99,471
Eastern Wyoming	WYP	2.306%	102,409,215	196,588	115,404	102,524,619	196,876	182,721	102,707,340	197,162	1,095,409	103,802,750	198,390	1,347,845	105,150,595	200,737
Utah	UT	2.154%	302,171,285	541,372	657,411	302,828,696	542,978	1,129,988	303,958,684	544,582	1,723,832	305,682,516	547,144	2,320,813	308,003,330	550,774
Idaho	ID	2.029%	59,799,192	100,927	123,928	59,923,121	101,193	191,253	60,114,373	101,459	276,927	60,391,300	101,855	363,826	60,755,126	102,397
Western Wyoming	WYU	2.087%	20,485,563	35,647	(24,286)	20,461,277	35,605	(24,286)	20,436,991	35,563	(24,286)	20,412,705	35,520	(24,286)	20,388,418	35,478
Pre-merger Pacific	SG	1.090%	563,936	516	(9,135)	554,801	508	(9,135)	545,666	500	(9,135)	536,530	491	(9,135)	527,395	483
Pre-merger Utah	SG	1.196%	2,524,737	2,531	(27,040)	2,497,697	2,504	(27,040)	2,470,657	2,477	(27,040)	2,443,617	2,450	(27,040)	2,416,577	2,423
Post-merger	SG	3.474%	326,086,916	945,000	(603,907)	325,483,009	943,251	(603,907)	324,879,102	941,503	(550,833)	324,328,269	939,831	(599,082)	323,729,187	938,166
General Office	SO	6.249%	418,832,063	2,175,829	2,194,702	421,026,765	2,186,636	2,716,807	423,743,572	2,199,424	1,789,204	425,532,776	2,211,155	20,241,787	445,774,563	2,268,515
General Office	SG	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
General Office	SG	4.285%	226,577	809	(67)	226,510	809	(67)	226,443	809	(67)	226,375	808	(67)	226,308	808
Customer Service	CN	5.135%	14,249,172	61,205	(106,932)	14,142,240	60,748	(106,932)	14,035,308	60,290	(106,932)	13,928,376	59,832	(106,932)	13,821,444	59,375
Fuel Related	SE	3.583%	3,193,736	9,551	(11,152)	3,182,584	9,518	(11,152)	3,171,432	9,485	(11,152)	3,160,280	9,452	(11,152)	3,149,128	9,418
Total General Plant			1,552,513,924	4,643,082	2,493,523	1,555,007,447	4,653,596	3,918,890	1,558,926,337	4,666,862	4,094,832	1,563,021,169	4,680,942	78,686,516	1,641,707,685	4,795,096
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			33,103,701,065	92,143,490	245,648,407	33,349,349,472	92,426,486	91,647,741	33,440,997,213	92,705,552	2,376,645,562	35,817,642,775	94,525,525	334,544,627	36,152,187,402	96,669,395

PacifiCorp
Oregon General Rate Case - December 2025
Jun 2023 - Dec 2024 Depreciation & Amortization Expense

			Adjusted EPIS Balance	Depreciation Expense		Adjusted EPIS Balance	Depreciation Expense		Adjusted EPIS Balance	Depreciation Expense		Adjusted EPIS Balance	Depreciation Expense		Adjusted EPIS Balance	Depreciation Expense
Description	**Factor**	**2018 Rate**	**Aug 2024**	**Aug 2024**	**Adjustments**	**Sep 2024**	**Sep 2024**	**Adjustments**	**Oct 2024**	**Oct 2024**	**Adjustments**	**Nov 2024**	**Nov 2024**	**Adjustments**	**Dec 2024**	**Dec 2024**
AMORTIZATION EXPENSE																
Intangible Plant:																
California	CA	0.000%	472,206	-	(10)	472,196	-	(10)	472,186	-	(10)	472,177	-	(10)	472,167	-
Customer Service	CN	6.792%	230,021,817	1,302,309	(137,002)	229,884,816	1,301,534	(137,002)	229,747,814	1,300,758	(137,002)	229,610,812	1,299,983	(137,002)	229,473,811	1,299,207
Pre-merger Utah	SG	2.611%	448,804	979	(2,057)	446,747	974	(2,057)	444,691	970	(2,057)	442,634	965	(2,057)	440,577	961
Pre-merger Pacific	SG	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Idaho	ID	0.000%	4,356,188	-	(29)	4,356,159	-	(29)	4,356,130	-	(29)	4,356,102	-	(29)	4,356,073	-
Oregon	OR	0.243%	4,608,017	935	(402)	4,607,614	935	(402)	4,607,212	935	(402)	4,606,809	935	(402)	4,606,407	935
Fuel Related	SE	20.000%	5,687	97	(244)	5,442	93	(244)	5,198	89	(244)	4,954	85	(244)	4,710	81
Post-merger	SG	2.847%	207,196,114	491,589	(50,641)	207,145,473	491,469	(50,641)	207,094,832	491,349	(50,641)	207,044,191	491,229	(50,641)	206,993,550	491,109
Hydro Relicensing	SG-P	2.593%	103,389,757	223,423	(4,666)	103,385,091	223,413	(4,666)	103,380,425	223,403	(4,666)	103,375,760	223,393	(4,666)	103,371,094	223,383
Hydro Relicensing	SG-U	3.225%	9,815,331	26,399	(14,920)	9,800,410	26,359	(14,920)	9,785,490	26,319	(14,920)	9,770,570	26,279	(14,920)	9,755,649	26,239
General Office	SO	7.288%	531,631,006	3,222,739	160,748,986	692,379,992	3,717,085	(436,500)	691,943,492	4,203,924	934,994	692,878,486	4,205,437	8,196,264	701,074,750	4,233,167
Utah	UT	1.297%	7,521,443	8,132	(301)	7,521,142	8,132	(301)	7,520,840	8,132	(301)	7,520,539	8,131	(301)	7,520,237	8,131
Washington	WA	0.006%	2,021,868	10	-	2,021,868	10	-	2,021,868	10	-	2,021,868	10	-	2,021,868	10
Eastern Wyoming	WYP	1.275%	5,313,065	5,646	(2,628)	5,310,438	5,643	(2,628)	5,307,810	5,640	(2,628)	5,305,182	5,637	(2,628)	5,302,554	5,634
Western Wyoming	WYU	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Klamath		0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Intangible Plant			1,106,801,302	5,282,258	160,536,087	1,267,337,389	5,775,647	(649,400)	1,266,687,989	6,261,528	722,094	1,267,410,084	6,262,084	7,983,365	1,275,393,448	6,288,857
Hydro Production Plant:																
Pre-merger Pacific	SG	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG-P	2.125%	14,768,097	26,156	-	14,768,097	26,156	-	14,768,097	26,156	-	14,768,097	26,156	-	14,768,097	26,156
Post-merger	SG-U	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Hydro Plant			14,768,097	26,156	-	14,768,097	26,156	-	14,768,097	26,156	-	14,768,097	26,156	-	14,768,097	26,156
Other Production Plant:																
Oregon Solar	OR	13.675%	516,566	5,887	-	516,566	5,887	-	516,566	5,887	-	516,566	5,887	-	516,566	5,887
Total Other Plant			516,566	5,887	-	516,566	5,887	-	516,566	5,887	-	516,566	5,887	-	516,566	5,887
General Plant:																
California	CA	0.053%	505,860	22	-	505,860	22	-	505,860	22	-	505,860	22	-	505,860	22
General Office	CN	0.000%	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Oregon	OR	2.456%	5,683,822	11,632	-	5,683,822	11,632	-	5,683,822	11,632	-	5,683,822	11,632	-	5,683,822	11,632
General Office	SO	1.883%	2,196,886	3,447	-	2,196,886	3,447	-	2,196,886	3,447	-	2,196,886	3,447	-	2,196,886	3,447
Utah	UT	0.000%	33,127	-	-	33,127	-	-	33,127	-	-	33,127	-	-	33,127	-
Washington	WA	4.191%	2,573,715	8,988	-	2,573,715	8,988	-	2,573,715	8,988	-	2,573,715	8,988	-	2,573,715	8,988
Eastern Wyoming	WYP	3.644%	4,752,256	14,430	-	4,752,256	14,430	-	4,752,256	14,430	-	4,752,256	14,430	-	4,752,256	14,430
Idaho	ID	0.000%	333,771	-	-	333,771	-	-	333,771	-	-	333,771	-	-	333,771	-
Total General Plant			16,079,436	38,520	-	16,079,436	38,520	-	16,079,436	38,520	-	16,079,436	38,520	-	16,079,436	38,520
Total Amortization			1,138,165,401	5,352,821	160,536,087	1,298,701,488	5,846,210	(649,400)	1,298,052,088	6,332,091	722,094	1,298,774,182	6,332,647	7,983,365	1,306,757,547	6,359,420
Total Depreciation & Amortization			34,241,866,466	97,496,311	406,184,494	34,648,050,960	98,272,696	90,998,341	34,739,049,301	99,037,643	2,377,367,656	37,116,416,957	100,858,172	342,527,992	37,458,944,949	103,028,815

PacifiCorp
Oregon General Rate Case - December 2025
Jun 2023 - Dec 2024 Depreciation & Amortization Expense

Description	Factor	2018 Rate	Test Period Annualized Depreciation Expense - CY 2024
DEPRECIATION EXPENSE			
Steam Production Plant:			
Pre-merger Pacific	SG	5.094%	51,128,792
Pre-merger Utah	SG	5.005%	52,417,139
Post-merger	SG	6.327%	319,420,104
Geothermal - Blundell	SG	6.327%	1,921,090
Carbon	SG	6.327%	-
Pollution Control Equipment	SG	6.327%	84,567
Pollution Control Equipment	SG	0.000%	-
Post-merger	SG	0.000%	-
Total Steam Plant			424,971,693
Hydro Production Plant:			
Pre-merger Pacific	SG	2.208%	4,041,599
Pre-merger Utah	SG	3.187%	1,242,786
Post-merger	SG-P	2.767%	21,103,284
Post-merger	SG-U	4.631%	9,084,988
Klamath - New Capital	SG-P	20.000%	282,548
Future Use	Future Use		-
Total Hydro Plant			35,755,204
Other Production Plant:			
Pre-merger Utah	SG	0.000%	-
Post-merger	SG	3.505%	68,642,057
Post-merger Wind	SG-W	4.208%	140,561,395
Oregon Solar	OR	13.675%	61,373
Post-merger	SG	4.832%	4,271,402
Total Other Plant			213,536,227
Transmission Plant:			
Pre-merger Pacific	SG	1.699%	8,005,984
Pre-merger Utah	SG	1.672%	10,118,645
Post-merger	SG	1.725%	175,626,159
Total Transmission Plant			193,750,789
Distribution Plant:			
California	CA	2.710%	15,618,897
Oregon	OR	2.276%	61,570,633
Washington	WA	2.581%	17,099,473
Eastern Wyoming	WYP	2.657%	20,607,376
Utah	UT	2.548%	107,174,945
Idaho	ID	2.540%	11,921,466
Western Wyoming	WYU	2.654%	4,041,475
Total Distribution Plant			238,034,265
General Plant:			
California	CA	2.087%	498,637
Oregon	OR	2.291%	6,424,180
Washington	WA	2.294%	1,226,231
Eastern Wyoming	WYP	2.306%	2,424,385
Utah	UT	2.154%	6,634,278
Idaho	ID	2.029%	1,232,450
Western Wyoming	WYU	2.087%	425,485
Pre-merger Pacific	SG	1.090%	5,747
Pre-merger Utah	SG	1.196%	28,913
Post-merger	SG	3.474%	11,247,587
General Office	SO	6.249%	27,854,589
General Office	SG	0.000%	-
General Office	SG	4.285%	9,696
Customer Service	CN	5.135%	709,753
Fuel Related	SE	3.583%	112,819
Total General Plant			58,834,749
Mining Plant:			
Coal Mine	SE	0.000%	-
Total Mining Plant			-
Total Depreciation Expense			1,164,882,926

PacifiCorp
Oregon General Rate Case - December 2025
Jun 2023 - Dec 2024 Depreciation & Amortization Expense

Description	Factor	2018 Rate	Test Period Annualized Depreciation Expense - CY 2024
AMORTIZATION EXPENSE			
Intangible Plant:			
California	CA	0.000%	-
Customer Service	CN	6.792%	15,585,835
Pre-merger Utah	SG	2.611%	11,504
Pre-merger Pacific	SG	0.000%	-
Idaho	ID	0.000%	-
Oregon	OR	0.243%	11,216
Fuel Related	SE	20.000%	942
Post-merger	SG	2.847%	5,892,582
Hydro Relicensing	SG-P	2.593%	2,680,531
Hydro Relicensing	SG-U	3.225%	314,627
General Office	SO	7.288%	51,096,692
Utah	UT	1.297%	97,571
Washington	WA	0.006%	125
Eastern Wyoming	WYP	1.275%	67,597
Western Wyoming	WYU	0.000%	-
Klamath		0.000%	-
Total Intangible Plant			75,759,221
Hydro Production Plant:			
Pre-merger Pacific	SG	0.000%	-
Post-merger	SG-P	2.125%	313,878
Post-merger	SG-U	0.000%	-
Total Hydro Plant			313,878
Other Production Plant:			
Oregon Solar	OR	13.675%	70,641
Total Other Plant			70,641
General Plant:			
California	CA	0.053%	269
General Office	CN	0.000%	-
Oregon	OR	2.456%	139,579
General Office	SO	1.883%	41,363
Utah	UT	0.000%	-
Washington	WA	4.191%	107,861
Eastern Wyoming	WYP	3.644%	173,163
Idaho	ID	0.000%	-
Total General Plant			462,235
Total Amortization			76,605,976
Total Depreciation & Amortization			**1,241,488,901**
			Ref. 6.1.3

PacifiCorp
Oregon General Rate Case - December 2025
Depreciation Reserve

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Steam Depreciation Reserve	108SP	3	(71,785,506)	SG	26.884%	(19,298,928)	
Steam Depreciation Reserve	108SP	3	(74,309,228)	SG	26.884%	(19,977,409)	
Steam Depreciation Reserve	108SP	3	(1,501,978,818)	SG	26.884%	(403,794,345)	
Steam Depreciation Reserve	108SP	3	(15,622,993)	SG	26.884%	(4,200,110)	
Steam Depreciation Reserve	108SP	3	-	SG	26.884%	-	
Steam Depreciation Reserve	108SP	3	(91,762)	SG	26.884%	(24,669)	
Steam Depreciation Reserve	108SP	3	-	SG	26.884%	-	
Hydro Depreciation Reserve	108HP	3	(5,353,631)	SG	26.884%	(1,439,279)	
Hydro Depreciation Reserve	108HP	3	(1,265,984)	SG	26.884%	(340,349)	
Hydro Depreciation Reserve	108HP	3	(23,460,277)	SG-P	26.884%	(6,307,098)	
Hydro Depreciation Reserve	108HP	3	(10,984,830)	SG-U	26.884%	(2,953,179)	
Hydro Depreciation Reserve	108HP	3	(317,866)	SG-P	26.884%	(85,456)	
Other Depreciation Reserve	108OP	3	-	SG	26.884%	-	
Other Depreciation Reserve	108OP	3	(66,011,402)	SG	26.884%	(17,746,609)	
Other Depreciation Reserve	108OP	3	(207,809,648)	SG-W	26.884%	(55,867,872)	
Other Depreciation Reserve	108OP	3	(81,121)	OR	Situs	(81,121)	
Other Depreciation Reserve	108OP	3	(5,226,065)	SG	26.884%	(1,404,984)	
Transmission Depreciation Reserve	108TP	3	(8,645,566)	SG	26.884%	(2,324,287)	
Transmission Depreciation Reserve	108TP	3	(8,948,549)	SG	26.884%	(2,405,742)	
Transmission Depreciation Reserve	108TP	3	(206,206,530)	SG	26.884%	(55,436,888)	
Distribution Depreciation Reserve	108360	3	(1,839,156)	OR	Situs	(357,436)	
Distribution Depreciation Reserve	108361	3	(3,528,119)	OR	Situs	(685,682)	
Distribution Depreciation Reserve	108362	3	(29,608,252)	OR	Situs	(5,754,294)	
Distribution Depreciation Reserve	108364	3	(36,449,736)	OR	Situs	(7,083,920)	
Distribution Depreciation Reserve	108365	3	(22,832,125)	OR	Situs	(4,437,370)	
Distribution Depreciation Reserve	108366	3	(11,591,740)	OR	Situs	(2,252,827)	
Distribution Depreciation Reserve	108367	3	(26,402,607)	OR	Situs	(5,131,285)	
Distribution Depreciation Reserve	108368	3	(38,544,582)	OR	Situs	(7,491,049)	
Distribution Depreciation Reserve	108369	3	(24,588,811)	OR	Situs	(4,778,778)	
Distribution Depreciation Reserve	108370	3	(6,974,789)	OR	Situs	(1,355,534)	
Distribution Depreciation Reserve	108371	3	(210,838)	OR	Situs	(40,976)	
Distribution Depreciation Reserve	108373	3	(1,501,551)	OR	Situs	(291,823)	
General Depreciation Reserve	108GP	3	(492,685)	CA	Situs	-	
General Depreciation Reserve	108GP	3	(5,601,083)	OR	Situs	(5,601,083)	
General Depreciation Reserve	108GP	3	(1,396,912)	WA	Situs	-	
General Depreciation Reserve	108GP	3	(3,692,103)	WYP	Situs	-	
General Depreciation Reserve	108GP	3	(12,910,919)	UT	Situs	-	
General Depreciation Reserve	108GP	3	(2,418,107)	ID	Situs	-	
General Depreciation Reserve	108GP	3	(823,116)	WYU	Situs	-	
General Depreciation Reserve	108GP	3	155,071	SG	26.884%	41,690	
General Depreciation Reserve	108GP	3	440,927	SG	26.884%	118,539	
General Depreciation Reserve	108GP	3	(13,642,892)	SG	26.884%	(3,667,777)	
General Depreciation Reserve	108GP	3	(14,468,314)	SO	27.425%	(3,968,003)	
General Depreciation Reserve	108GP	3	-	SG	26.884%	-	
General Depreciation Reserve	108GP	3	(13,355)	SG	26.884%	(3,590)	
General Depreciation Reserve	108GP	3	818,962	CN	30.706%	251,467	
General Depreciation Reserve	108GP	3	(114,033)	SE	26.339%	(30,035)	
Mining Depreciation Reserve	108MP	3	-	SE	26.339%	-	
			(2,466,330,640)			(646,208,089)	6.2.2

Description of Adjustment

This adjustment steps forward the depreciation reserve to a December 2024 adjusted level. Accumulated depreciation and amortization balances are calculated by applying pro forma depreciation and amortization expense and plant retirements to the June 2023 balances. The reserve balances are calculated on a monthly basis to walk the balances forward from June 30, 2023 to December 31, 2024. An incremental amount has been added to the December 31, 2024 balance to reflect the annualized depreciation expense in adjustment 6.1.

PacifiCorp
Oregon General Rate Case - December 2025
Amortization Reserve

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Intangible Amortization Reserve	111IP	3	174	CA	Situs	-	
Intangible Amortization Reserve	111IP	3	(20,982,514)	CN	30.706%	(6,442,792)	
Intangible Amortization Reserve	111IP	3	518	ID	Situs	-	
Intangible Amortization Reserve	111IP	3	19,361	SG	26.884%	5,205	
Intangible Amortization Reserve	111IP	3	(9,587)	OR	Situs	(9,587)	
Intangible Amortization Reserve	111IP	3	2,617	SE	26.339%	689	
Intangible Amortization Reserve	111IP	3	(7,938,146)	SG	26.884%	(2,134,104)	
Intangible Amortization Reserve	111IP	3	(3,937,723)	SG-P	26.884%	(1,058,624)	
Intangible Amortization Reserve	111IP	3	(206,982)	SG-U	26.884%	(55,645)	
Intangible Amortization Reserve	111IP	3	(57,492,675)	SO	27.425%	(15,767,634)	
Intangible Amortization Reserve	111IP	3	-	SG	26.884%	-	
Intangible Amortization Reserve	111IP	3	(140,959)	UT	Situs	-	
Intangible Amortization Reserve	111IP	3	(187)	WA	Situs	-	
Intangible Amortization Reserve	111IP	3	(54,348)	WYP	Situs	-	
Intangible Amortization Reserve	111IP	3	-	WYU	Situs	-	
Intangible Amortization Reserve	111IP	3	-	SG	26.884%	-	
Hydro Amortization Reserve	111HP	3	-	SG	26.884%	-	
Hydro Amortization Reserve	111HP	3	(470,817)	SG-P	26.884%	(126,575)	
Hydro Amortization Reserve	111HP	3	-	SG-U	26.884%	-	
Other Amortization Reserve	111OP	3	(105,962)	OR	Situs	(105,962)	
General Amortization Reserve	111GP	3	(403)	CA	Situs	-	
General Amortization Reserve	111GP	3	-	CN	30.706%	-	
General Amortization Reserve	111GP	3	-	ID	Situs	-	
General Amortization Reserve	111GP	3	(209,368)	OR	Situs	(209,368)	
General Amortization Reserve	111GP	3	(62,045)	SO	27.425%	(17,016)	
General Amortization Reserve	111GP	3	-	UT	Situs	-	
General Amortization Reserve	111GP	3	(161,792)	WA	Situs	-	
General Amortization Reserve	111GP	3	(259,745)	WYP	Situs	-	
General Amortization Reserve	111GP	3	-	WYU	Situs	-	
			(92,010,583)			(25,921,413)	6.2.3
			(2,558,341,223)			(672,129,501)	6.2.3
Coal Depreciable Life Update:							
Depreciation Expense	403SP	3	(3,108,984)	SG	26.884%	(835,824)	
Depreciation Reserve	108SP	3	6,217,969	SG	26.884%	1,671,648	
			3,108,984			835,824	6.2.10

Description of Adjustment:

This adjustment steps forward the depreciation reserve to a December 2024 adjusted level. Accumulated depreciation and amortization balances are calculated by applying pro forma depreciation and amortization expense and plant retirements to the June 2023 balances. The reserve balances are calculated on a monthly basis to walk the balances forward from June 30, 2023 to December 31, 2024. An incremental amount has been added to the December 31, 2024 balance to reflect the annualized depreciation expense in adjustment 6.1.

This pro forma adjustment also 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. This treatment was approved in the Company's 2023 general rate case, Docket UE-399.

PacifiCorp
Oregon General Rate Case - December 2025
Depreciation and Amortization Reserve Summary

Description	Account	Factor	12 ME Jun 2023 Reserve	Test Period Reserve	Adjustment to Test Period
DEPRECIATION RESERVE					
Steam Production Plant:					
Pre-merger Pacific	108SP	SG	(824,873,009)	(896,658,516)	(71,785,506)
Pre-merger Utah	108SP	SG	(769,219,505)	(843,528,732)	(74,309,228)
Post-merger	108SP	SG	(2,339,730,354)	(3,841,709,172)	(1,501,978,818)
Renewable - Blundell	108SP	SG	-	(15,622,993)	(15,622,993)
Carbon	108SP	SG	-	-	-
Pollution Control Equipment	108SP	SG	-	(91,762)	(91,762)
Post-merger	108SP	SG	-	-	-
Total Steam Plant			(3,933,822,868)	(5,597,611,175)	(1,663,788,306)
Hydro Production Plant:					
Pre-merger Pacific	108HP	SG	(145,923,755)	(151,277,386)	(5,353,631)
Pre-merger Utah	108HP	SG	(32,553,755)	(33,819,739)	(1,265,984)
Post-merger	108HP	SG-P	(199,044,187)	(222,504,464)	(23,460,277)
Post-merger	108HP	SG-U	(76,852,964)	(87,837,794)	(10,984,830)
Klamath - New Capital	108HP	SG-P	-	(317,866)	(317,866)
Total Hydro Plant			(454,374,661)	(495,757,249)	(41,382,588)
Other Production Plant:					
Pre-merger Utah	108OP	SG	-	-	-
Post-merger	108OP	SG	(568,854,645)	(634,866,047)	(66,011,402)
Post-merger Wind	108OP	SG-W	115,697,229	(92,112,420)	(207,809,648)
Oregon Solar	108OP	OR	(310)	(81,430)	(81,121)
Post-merger	108OP	SG	(50,136,554)	(55,362,620)	(5,226,065)
Total Other Plant			(503,294,280)	(782,422,516)	(279,128,236)
Transmission Plant:					
Pre-merger Pacific	108TP	SG	(349,536,968)	(358,182,534)	(8,645,566)
Pre-merger Utah	108TP	SG	(420,976,303)	(429,924,852)	(8,948,549)
Post-merger	108TP	SG	(1,424,877,030)	(1,631,083,561)	(206,206,530)
Total Transmission Plant			(2,195,390,301)	(2,419,190,946)	(223,800,646)
Distribution Plant:					
California	108364	CA	(152,881,050)	(167,750,424)	(14,869,374)
Oregon	108364	OR	(1,152,479,815)	(1,192,140,788)	(39,660,973)
Washington	108364	WA	(294,187,684)	(311,895,255)	(17,707,571)
Eastern Wyoming	108364	WYP	(314,941,969)	(334,637,341)	(19,695,372)
Utah	108364	UT	(1,146,620,099)	(1,245,956,733)	(99,336,634)
Idaho	108364	ID	(161,520,333)	(169,071,974)	(7,551,641)
Western Wyoming	108364	WYU	(67,528,959)	(72,779,701)	(5,250,742)
Total Distribution Plant			(3,290,159,909)	(3,494,232,215)	(204,072,306)
General Plant:					
California	108GP	CA	(8,082,410)	(8,575,095)	(492,685)
Oregon	108GP	OR	(91,140,276)	(96,741,359)	(5,601,083)
Washington	108GP	WA	(26,360,778)	(27,757,690)	(1,396,912)
Eastern Wyoming	108GP	WYP	(32,641,695)	(36,333,798)	(3,692,103)
Utah	108GP	UT	(114,042,446)	(126,953,365)	(12,910,919)
Idaho	108GP	ID	(23,374,734)	(25,792,840)	(2,418,107)
Western Wyoming	108GP	WYU	(7,871,044)	(8,694,160)	(823,116)
Pre-merger Pacific	108GP	SG	(473,066)	(317,995)	155,071
Pre-merger Utah	108GP	SG	(2,092,186)	(1,651,259)	440,927
Post-merger	108GP	SG	(142,863,893)	(156,506,785)	(13,642,892)
General Office	108GP	SO	(121,361,528)	(135,829,842)	(14,468,314)
General Office	108GP	SG	-	-	-
General Office	108GP	SG	(149,363)	(162,717)	(13,355)
Customer Service	108GP	CN	(6,304,713)	(5,485,751)	818,962
Fuel Related	108GP	SE	(1,798,513)	(1,912,546)	(114,033)
Total General Plant			(578,556,645)	(632,715,203)	(54,158,558)
Mining Plant:					
Coal Mine	108MP	SE	-	-	-
Total Mining Plant			-	-	-
Total Depreciation Reserve			(10,955,598,664)	(13,421,929,304)	**(2,466,330,640)**
					Ref 6.2

PacifiCorp
Oregon General Rate Case - December 2025
Depreciation and Amortization Reserve Summary

Description	Account	Factor	12 ME Jun 2023 Reserve	Test Period Reserve	Adjustment to Test Period
AMORTIZATION RESERVE					
Intangible Plant:					
California	111IP	CA	-	174	174
Customer Service	111IP	CN	(185,912,323)	(206,894,836)	(20,982,514)
Idaho	111IP	ID	(1,000,000)	(999,482)	518
Pre-merger Utah	111IP	SG	(421,999)	(402,639)	19,361
Oregon	111IP	OR	(149,822)	(159,409)	(9,587)
Fuel Related	111IP	SE	(5,540)	(2,923)	2,617
Post-merger	111IP	SG	(108,800,207)	(116,738,353)	(7,938,146)
Hydro Relicensing	111IP	SG-P	(45,827,311)	(49,765,034)	(3,937,723)
Hydro Relicensing	111IP	SG-U	(6,403,898)	(6,610,880)	(206,982)
General Office	111IP	SO	(363,643,446)	(421,136,121)	(57,492,675)
Pre-merger Pacific	111IP	SG	-	-	-
Utah	111IP	UT	(209,309)	(350,268)	(140,959)
Washington	111IP	WA	(358)	(545)	(187)
Eastern Wyoming	111IP	WYP	(307,450)	(361,798)	(54,348)
Western Wyoming	111IP	WYU	-	-	-
General Office	111IP	SG	-	-	-
Total Intangible Plant			(712,681,663)	(803,422,114)	(90,740,451)
Hydro Production Plant:					
Pre-merger Pacific	111HP	SG	-	-	-
Post-merger	111HP	SG-P	(3,764,748)	(4,235,565)	(470,817)
Post-merger	111HP	SG-U	-	-	-
Total Hydro Plant			(3,764,748)	(4,235,565)	(470,817)
Other Production Plant:					
Oregon	111OP	OR	(92,148)	(198,109)	(105,962)
Total Other Plant			(92,148)	(198,109)	(105,962)
General Plant:					
California	111GP	CA	(505,860)	(506,263)	(403)
General Office	111GP	CN	-	-	-
General Office	111GP	ID	(333,771)	(333,771)	-
Oregon	111GP	OR	(5,064,283)	(5,273,651)	(209,368)
General Office	111GP	SO	(1,442,803)	(1,504,848)	(62,045)
Utah	111GP	UT	(33,127)	(33,127)	-
Washington	111GP	WA	(2,049,008)	(2,210,800)	(161,792)
Eastern Wyoming	111GP	WYP	(4,642,505)	(4,902,250)	(259,745)
Western Wyoming	111GP	WYU	-	-	-
Total General Plant			(14,071,356)	(14,764,710)	(693,353)
Total Amortization Reserve			(730,609,915)	(822,620,498)	**(92,010,583)**
					Ref 6.2.1
Total Depreciation & Amortization Reserve			(11,686,208,579)	**(14,244,549,803)**	**(2,558,341,223)**
				Ref. 6.2.9	**Ref 6.2.1**

PacifiCorp
Oregon General Rate Case - December 2025
Jun 2023 - December 2024 Depreciation & Amortization Reserve

Description	Factor	Adjusted Reserve Balance Jun 2023	Adjustments	Adjusted Reserve Balance Jul 2023	Adjustments	Adjusted Reserve Balance Aug 2023	Adjustments	Adjusted Reserve Balance Sep 2023	Adjustments	Adjusted Reserve Balance Oct 2023	Adjustments	Adjusted Reserve Balance Nov 2023	Adjustments	Adjusted Reserve Balance Dec 2023	Adjustments
DEPRECIATION RESERVE															
Steam Production Plant:															
Pre-merger Pacific	SG	(824,873,009)	(4,002,865)	(828,875,874)	(4,001,683)	(832,877,557)	(4,000,500)	(836,878,057)	(3,999,318)	(840,877,374)	(3,998,135)	(844,875,510)	(3,996,953)	(848,872,462)	(3,995,770)
Pre-merger Utah	SG	(769,219,505)	(4,141,058)	(773,360,563)	(4,140,037)	(777,500,600)	(4,139,015)	(781,639,615)	(4,137,994)	(785,777,609)	(4,136,973)	(789,914,582)	(4,135,951)	(794,050,533)	(4,134,930)
Post-merger	SG	(3,433,555,687)	(22,204,220)	(3,455,759,907)	(22,207,506)	(3,477,967,413)	(22,306,176)	(3,500,273,589)	(22,401,878)	(3,522,675,466)	(22,422,134)	(3,545,097,600)	(22,481,468)	(3,567,579,068)	(22,515,203)
Renewable - Blundell	SG	(12,751,180)	(158,431)	(12,909,611)	(158,431)	(13,068,042)	(158,431)	(13,226,473)	(158,431)	(13,384,905)	(158,431)	(13,543,336)	(158,567)	(13,701,903)	(158,738)
Carbon	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pollution Control Equipment	SG	-	(445)	(445)	(890)	(1,336)	(890)	(2,226)	(890)	(3,117)	(1,204)	(4,321)	(2,874)	(7,195)	(4,229)
Post-merger	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Steam Plant		(5,040,399,381)	(30,507,020)	(5,070,906,401)	(30,508,547)	(5,101,414,948)	(30,605,013)	(5,132,019,961)	(30,698,511)	(5,162,718,472)	(30,716,877)	(5,193,435,349)	(30,775,812)	(5,224,211,160)	(30,808,869)
Hydro Production Plant:															
Pre-merger Pacific	SG	(145,923,755)	(298,338)	(146,222,093)	(298,265)	(146,520,358)	(298,192)	(146,818,550)	(298,119)	(147,116,669)	(298,046)	(147,414,714)	(297,972)	(147,712,687)	(297,899)
Pre-merger Utah	SG	(32,553,755)	(71,451)	(32,625,205)	(71,361)	(32,696,567)	(71,272)	(32,767,838)	(71,182)	(32,839,021)	(71,093)	(32,910,113)	(71,003)	(32,981,117)	(70,914)
Post-merger	SG-P	(199,044,187)	(1,147,399)	(200,191,586)	(1,151,271)	(201,342,857)	(1,156,376)	(202,499,233)	(1,163,061)	(203,662,294)	(1,168,868)	(204,831,162)	(1,188,386)	(206,019,548)	(1,204,955)
Post-merger	SG-U	(76,852,964)	(531,205)	(77,384,169)	(531,111)	(77,915,280)	(531,311)	(78,446,591)	(531,366)	(78,977,957)	(532,164)	(79,510,121)	(542,373)	(80,052,494)	(551,546)
Klamath - New Capital	SG-P	-	-	-	-	-	-	-	-	-	(11,773)	(11,773)	(23,546)	(35,318)	(23,546)
Total Hydro Plant		(454,374,661)	(2,048,393)	(456,423,053)	(2,052,008)	(458,475,061)	(2,057,150)	(460,532,212)	(2,063,728)	(462,595,940)	(2,081,943)	(464,677,883)	(2,123,280)	(466,801,163)	(2,148,860)
Other Production Plant:															
Pre-merger Utah	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG	(568,854,645)	(3,627,058)	(572,481,703)	(3,621,142)	(576,102,844)	(3,615,157)	(579,718,001)	(3,663,461)	(583,381,462)	(3,713,747)	(587,095,209)	(3,719,024)	(590,814,233)	(3,722,432)
Post-merger Wind	SG-W	115,697,229	(11,250,220)	104,447,009	(11,252,751)	93,194,257	(11,257,243)	81,937,015	(11,262,606)	70,674,408	(11,407,646)	59,266,762	(11,558,736)	47,708,026	(11,569,945)
Oregon Solar	OR	(310)	(1,610)	(1,920)	(3,034)	(4,954)	(3,746)	(8,700)	(3,746)	(12,446)	(3,746)	(16,192)	(3,865)	(20,057)	(3,985)
Post-merger	SG	(50,136,554)	(291,640)	(50,428,194)	(291,374)	(50,719,568)	(291,108)	(51,010,676)	(290,996)	(51,301,672)	(291,354)	(51,593,026)	(291,663)	(51,884,689)	(291,510)
Total Other Plant		(503,294,280)	(15,170,528)	(518,464,808)	(15,168,301)	(533,633,109)	(15,167,253)	(548,800,362)	(15,220,810)	(564,021,172)	(15,416,493)	(579,437,665)	(15,573,287)	(595,010,952)	(15,587,872)
Transmission Plant:															
Pre-merger Pacific	SG	(349,536,968)	(483,639)	(350,020,607)	(483,373)	(350,503,980)	(483,107)	(350,987,087)	(482,840)	(351,469,927)	(482,574)	(351,952,501)	(482,307)	(352,434,808)	(482,041)
Pre-merger Utah	SG	(420,976,303)	(503,211)	(421,479,514)	(502,725)	(421,982,239)	(502,240)	(422,484,479)	(501,754)	(422,986,233)	(501,269)	(423,487,502)	(500,783)	(423,988,285)	(500,298)
Post-merger	SG	(1,424,877,030)	(8,391,309)	(1,433,268,339)	(8,420,653)	(1,441,688,992)	(8,445,189)	(1,450,134,181)	(8,467,869)	(1,458,602,050)	(8,507,135)	(1,467,109,185)	(8,581,439)	(1,475,690,624)	(8,638,541)
Total Transmission Plant		(2,195,390,301)	(9,378,159)	(2,204,768,460)	(9,406,752)	(2,214,175,212)	(9,430,535)	(2,223,605,747)	(9,452,463)	(2,233,058,210)	(9,490,977)	(2,242,549,187)	(9,564,529)	(2,252,113,717)	(9,620,879)
Distribution Plant:															
California	CA	(152,881,050)	(528,330)	(153,409,380)	(536,318)	(153,945,699)	(556,230)	(154,501,928)	(587,459)	(155,089,387)	(612,091)	(155,701,479)	(627,930)	(156,329,409)	(634,948)
Oregon	OR	(1,152,479,815)	(2,048,413)	(1,154,528,227)	(2,059,860)	(1,156,588,088)	(2,084,053)	(1,158,672,141)	(2,106,637)	(1,160,778,778)	(2,115,778)	(1,162,894,555)	(2,130,622)	(1,165,025,177)	(2,142,319)
Washington	WA	(294,187,684)	(931,044)	(295,118,727)	(937,562)	(296,056,290)	(941,470)	(296,997,759)	(942,274)	(297,940,034)	(942,805)	(298,882,839)	(943,312)	(299,826,151)	(944,301)
Eastern Wyoming	WYP	(314,941,969)	(1,041,633)	(315,983,602)	(1,045,705)	(317,029,307)	(1,049,976)	(318,079,283)	(1,052,653)	(319,131,936)	(1,055,442)	(320,187,378)	(1,058,631)	(321,246,008)	(1,061,292)
Utah	UT	(1,146,620,099)	(4,823,049)	(1,151,443,148)	(4,865,353)	(1,156,308,500)	(4,899,959)	(1,161,208,459)	(4,936,887)	(1,166,145,346)	(4,991,654)	(1,171,137,001)	(5,096,807)	(1,176,233,808)	(5,184,640)
Idaho	ID	(161,520,333)	(369,467)	(161,889,800)	(373,282)	(162,263,082)	(376,318)	(162,639,400)	(379,030)	(163,018,430)	(381,288)	(163,399,719)	(383,437)	(163,783,155)	(385,341)
Western Wyoming	WYU	(67,528,959)	(292,968)	(67,821,927)	(292,867)	(68,114,795)	(292,767)	(68,407,561)	(292,666)	(68,700,227)	(292,565)	(68,992,792)	(292,464)	(69,285,256)	(292,363)
Total Distribution Plant		(3,290,159,909)	(10,034,903)	(3,300,194,812)	(10,110,948)	(3,310,305,760)	(10,200,773)	(3,320,506,532)	(10,297,606)	(3,330,804,138)	(10,391,624)	(3,341,195,762)	(10,533,203)	(3,351,728,965)	(10,645,204)
General Plant:															
California	CA	(8,082,410)	(26,241)	(8,108,651)	(26,213)	(8,134,865)	(26,169)	(8,161,034)	(26,179)	(8,187,213)	(26,182)	(8,213,395)	(26,186)	(8,239,581)	(26,157)
Oregon	OR	(91,140,276)	(232,735)	(91,373,011)	(234,305)	(91,607,316)	(235,715)	(91,843,031)	(239,205)	(92,082,236)	(243,875)	(92,326,111)	(248,988)	(92,575,099)	(251,595)
Washington	WA	(26,360,778)	(71,705)	(26,432,483)	(71,871)	(26,504,353)	(71,760)	(26,576,114)	(72,215)	(26,648,328)	(73,179)	(26,721,508)	(74,146)	(26,795,654)	(74,559)
Eastern Wyoming	WYP	(32,641,695)	(193,846)	(32,835,541)	(193,935)	(33,029,477)	(194,065)	(33,223,542)	(194,144)	(33,417,686)	(198,072)	(33,615,758)	(202,254)	(33,818,012)	(202,756)
Utah	UT	(114,042,446)	(688,673)	(114,731,119)	(694,196)	(115,425,315)	(696,945)	(116,122,260)	(698,474)	(116,820,735)	(699,591)	(117,520,326)	(703,749)	(118,224,075)	(708,349)
Idaho	ID	(23,374,734)	(130,972)	(23,505,705)	(131,167)	(23,636,873)	(131,407)	(23,768,280)	(131,509)	(23,899,789)	(131,672)	(24,031,461)	(132,109)	(24,163,570)	(132,627)
Western Wyoming	WYU	(7,871,044)	(46,257)	(7,917,301)	(46,214)	(7,963,515)	(46,172)	(8,009,687)	(46,130)	(8,055,817)	(46,088)	(8,101,905)	(46,045)	(8,147,950)	(46,003)
Pre-merger Pacific	SG	(473,066)	8,511	(464,555)	8,520	(456,035)	8,528	(447,507)	8,536	(438,971)	8,545	(430,426)	8,553	(421,873)	8,561
Pre-merger Utah	SG	(2,092,186)	24,159	(2,068,027)	24,186	(2,043,841)	24,213	(2,019,628)	24,240	(1,995,389)	24,267	(1,971,122)	24,294	(1,946,828)	24,321
Post-merger	SG	(142,863,893)	(777,449)	(143,641,342)	(775,695)	(144,417,038)	(773,984)	(145,191,022)	(772,330)	(145,963,351)	(771,512)	(146,734,864)	(771,177)	(147,506,040)	(769,975)
General Office	SO	(121,361,528)	(550,205)	(121,911,733)	(552,248)	(122,463,981)	(565,990)	(123,029,971)	(595,119)	(123,625,090)	(617,665)	(124,242,756)	(642,089)	(124,884,845)	(663,712)
General Office	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-
General Office	SG	(149,363)	(745)	(150,108)	(745)	(150,852)	(744)	(151,597)	(744)	(152,341)	(744)	(153,085)	(744)	(153,829)	(743)
Customer Service	CN	(6,304,713)	39,778	(6,264,935)	40,236	(6,224,699)	40,693	(6,184,006)	41,151	(6,142,855)	41,608	(6,101,247)	42,066	(6,059,181)	42,524
Fuel Related	SE	(1,798,513)	(6,751)	(1,805,264)	(6,718)	(1,811,982)	(6,685)	(1,818,667)	(6,651)	(1,825,319)	(6,618)	(1,831,937)	(6,585)	(1,838,522)	(6,552)
Total General Plant		(578,556,645)	(2,653,130)	(581,209,775)	(2,660,366)	(583,870,142)	(2,676,204)	(586,546,346)	(2,708,774)	(589,255,120)	(2,740,779)	(591,995,899)	(2,779,161)	(594,775,060)	(2,807,624)
Mining Plant:															
Coal Mine	SE	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Mining Plant		-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Depreciation Reserve		(12,062,175,176)	(69,792,134)	(12,131,967,310)	(69,906,922)	(12,201,874,232)	(70,136,928)	(12,272,011,160)	(70,441,892)	(12,342,453,052)	(70,838,694)	(12,413,291,745)	(71,349,273)	(12,484,641,018)	(71,619,310)

PacifiCorp
Oregon General Rate Case - December 2025
Jun 2023 - December 2024 Depreciation & Amortization Reserve

Description	Factor	Adjusted Reserve Balance Jun 2023	Adjustments	Adjusted Reserve Balance Jul 2023	Adjustments	Adjusted Reserve Balance Aug 2023	Adjustments	Adjusted Reserve Balance Sep 2023	Adjustments	Adjusted Reserve Balance Oct 2023	Adjustments	Adjusted Reserve Balance Nov 2023	Adjustments	Adjusted Reserve Balance Dec 2023	Adjustments
AMORTIZATION RESERVE															
Intangible Plant:															
California	CA	-	10	10	10	19	10	29	10	39	10	48	10	58	10
Customer Service	CN	(185,912,323)	(1,175,388)	(187,087,711)	(1,174,613)	(188,262,323)	(1,173,837)	(189,436,161)	(1,173,062)	(190,609,222)	(1,172,286)	(191,781,509)	(1,171,511)	(192,953,020)	(1,170,735)
Idaho	ID	(1,000,000)	29	(999,971)	29	(999,942)	29	(999,914)	29	(999,885)	29	(999,856)	29	(999,827)	29
Pre-merger Utah	SG	(421,999)	1,020	(420,979)	1,024	(419,955)	1,029	(418,927)	1,033	(417,894)	1,038	(416,856)	1,042	(415,814)	1,046
Oregon	OR	(149,822)	(534)	(150,356)	(534)	(150,889)	(533)	(151,422)	(533)	(151,956)	(533)	(152,489)	(533)	(153,022)	(533)
Fuel Related	SE	(5,540)	94	(5,445)	99	(5,347)	103	(5,244)	107	(5,137)	111	(5,027)	115	(4,912)	119
Post-merger	SG	(108,800,207)	(442,510)	(109,242,717)	(442,390)	(109,685,107)	(442,270)	(110,127,376)	(442,149)	(110,569,526)	(442,029)	(111,011,555)	(441,909)	(111,453,464)	(441,789)
Hydro Relicensing	SG-P	(45,827,311)	(218,888)	(46,046,199)	(218,878)	(46,265,077)	(218,868)	(46,483,946)	(218,858)	(46,702,804)	(218,848)	(46,921,652)	(218,838)	(47,140,490)	(218,828)
Hydro Relicensing	SG-U	(6,403,898)	(12,000)	(6,415,899)	(11,960)	(6,427,859)	(11,920)	(6,439,779)	(11,880)	(6,451,659)	(11,840)	(6,463,499)	(11,800)	(6,475,298)	(11,760)
General Office	SO	(363,643,446)	(2,304,015)	(365,947,461)	(2,321,838)	(368,269,299)	(2,350,317)	(370,619,616)	(2,366,916)	(372,986,532)	(2,373,621)	(375,360,153)	(2,381,388)	(377,741,541)	(2,387,713)
Pre-merger Pacific	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Utah	UT	(209,309)	(7,835)	(217,144)	(7,835)	(224,979)	(7,834)	(232,814)	(7,834)	(240,648)	(7,834)	(248,481)	(7,833)	(256,315)	(7,833)
Washington	WA	(358)	(10)	(369)	(10)	(379)	(10)	(390)	(10)	(400)	(10)	(410)	(10)	(421)	(10)
Eastern Wyoming	WYP	(307,450)	(3,054)	(310,504)	(3,051)	(313,555)	(3,049)	(316,604)	(3,046)	(319,650)	(3,043)	(322,693)	(3,040)	(325,733)	(3,037)
Western Wyoming	WYU	-	-	-	-	-	-	-	-	-	-	-	-	-	-
General Office	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Intangible Plant		(712,681,663)	(4,163,082)	(716,844,745)	(4,179,948)	(721,024,692)	(4,207,470)	(725,232,162)	(4,223,111)	(729,455,273)	(4,228,859)	(733,684,131)	(4,235,668)	(737,919,799)	(4,241,035)
Hydro Production Plant:															
Pre-merger Pacific	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG-P	(3,764,748)	(26,156)	(3,790,905)	(26,156)	(3,817,061)	(26,156)	(3,843,218)	(26,156)	(3,869,374)	(26,156)	(3,895,531)	(26,156)	(3,921,687)	(26,156)
Post-merger	SG-U	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Hydro Plant		(3,764,748)	(26,156)	(3,790,905)	(26,156)	(3,817,061)	(26,156)	(3,843,218)	(26,156)	(3,869,374)	(26,156)	(3,895,531)	(26,156)	(3,921,687)	(26,156)
Other Production Plant:															
Oregon	OR	(92,148)	(5,887)	(98,035)	(5,887)	(103,921)	(5,887)	(109,808)	(5,887)	(115,695)	(5,887)	(121,582)	(5,887)	(127,468)	(5,887)
Total Other Plant		(92,148)	(5,887)	(98,035)	(5,887)	(103,921)	(5,887)	(109,808)	(5,887)	(115,695)	(5,887)	(121,582)	(5,887)	(127,468)	(5,887)
General Plant:															
California	CA	(505,860)	(22)	(505,882)	(22)	(505,904)	(22)	(505,927)	(22)	(505,949)	(22)	(505,972)	(22)	(505,994)	(22)
General Office	CN	-	-	-	-	-	-	-	-	-	-	-	-	-	-
General Office	ID	(333,771)	-	(333,771)	-	(333,771)	-	(333,771)	-	(333,771)	-	(333,771)	-	(333,771)	-
Oregon	OR	(5,064,283)	(11,632)	(5,075,915)	(11,632)	(5,087,546)	(11,632)	(5,099,178)	(11,632)	(5,110,810)	(11,632)	(5,122,441)	(11,632)	(5,134,073)	(11,632)
General Office	SO	(1,442,803)	(3,447)	(1,446,250)	(3,447)	(1,449,697)	(3,447)	(1,453,144)	(3,447)	(1,456,591)	(3,447)	(1,460,038)	(3,447)	(1,463,485)	(3,447)
Utah	UT	(33,127)	-	(33,127)	-	(33,127)	-	(33,127)	-	(33,127)	-	(33,127)	-	(33,127)	-
Washington	WA	(2,049,008)	(8,988)	(2,057,997)	(8,988)	(2,066,985)	(8,988)	(2,075,974)	(8,988)	(2,084,962)	(8,988)	(2,093,950)	(8,988)	(2,102,939)	(8,988)
Eastern Wyoming	WYP	(4,642,505)	(14,430)	(4,656,935)	(14,430)	(4,671,365)	(14,430)	(4,685,796)	(14,430)	(4,700,226)	(14,430)	(4,714,656)	(14,430)	(4,729,087)	(14,430)
Western Wyoming	WYU	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total General Plant		(14,071,356)	(38,520)	(14,109,876)	(38,520)	(14,148,396)	(38,520)	(14,186,915)	(38,520)	(14,225,435)	(38,520)	(14,263,954)	(38,520)	(14,302,474)	(38,520)
Total Amortization Reserve		(730,609,915)	(4,233,645)	(734,843,560)	(4,250,510)	(739,094,071)	(4,278,032)	(743,372,103)	(4,293,674)	(747,665,777)	(4,299,421)	(751,965,198)	(4,306,231)	(756,271,429)	(4,311,598)
Total Depreciation & Amortization Reserve		(12,792,785,092)	(74,025,778)	(12,866,810,870)	(74,157,432)	(12,940,968,302)	(74,414,961)	(13,015,383,263)	(74,735,565)	(13,090,118,828)	(75,138,115)	(13,165,256,943)	(75,655,504)	(13,240,912,447)	(75,930,907)

PacifiCorp
Oregon General Rate Case - December 2025
Jun 2023 - December 2024 Depreciation & Amortization Reserve

Description	Factor	Adjusted Reserve Balance Jan 2024	Adjustments	Adjusted Reserve Balance Feb 2024	Adjustments	Adjusted Reserve Balance Mar 2024	Adjustments	Adjusted Reserve Balance Apr 2024	Adjustments	Adjusted Reserve Balance May 2024	Adjustments	Adjusted Reserve Balance Jun 2024	Adjustments	Adjusted Reserve Balance Jul 2024	Adjustments
DEPRECIATION RESERVE															
Steam Production Plant:															
Pre-merger Pacific	SG	(852,868,232)	(3,994,588)	(856,862,820)	(3,993,405)	(860,856,225)	(3,992,222)	(864,848,447)	(3,991,040)	(868,839,487)	(3,989,857)	(872,829,345)	(3,988,675)	(876,818,019)	(3,987,492)
Pre-merger Utah	SG	(798,185,463)	(4,133,908)	(802,319,371)	(4,132,887)	(806,452,258)	(4,131,865)	(810,584,123)	(4,130,844)	(814,714,967)	(4,129,823)	(818,844,790)	(4,128,801)	(822,973,591)	(4,127,780)
Post-merger	SG	(3,590,094,271)	(22,503,829)	(3,612,598,100)	(22,506,251)	(3,635,104,351)	(22,662,664)	(3,657,767,015)	(22,806,979)	(3,680,573,995)	(22,813,286)	(3,703,387,280)	(22,819,138)	(3,726,206,418)	(22,812,521)
Renewable - Blundell	SG	(13,860,640)	(158,808)	(14,019,448)	(158,878)	(14,178,327)	(158,949)	(14,337,276)	(159,019)	(14,496,295)	(159,361)	(14,655,656)	(159,704)	(14,815,360)	(159,774)
Carbon	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pollution Control Equipment	SG	(11,423)	(4,229)	(15,652)	(4,229)	(19,881)	(4,229)	(24,110)	(4,229)	(28,339)	(4,586)	(32,924)	(5,814)	(38,738)	(6,685)
Post-merger	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Steam Plant		(5,255,020,030)	(30,795,361)	(5,285,815,391)	(30,795,650)	(5,316,611,042)	(30,949,930)	(5,347,560,971)	(31,092,111)	(5,378,653,082)	(31,096,913)	(5,409,749,995)	(31,102,131)	(5,440,852,126)	(31,094,252)
Hydro Production Plant:															
Pre-merger Pacific	SG	(148,010,586)	(297,826)	(148,308,412)	(297,753)	(148,606,165)	(297,680)	(148,903,845)	(297,607)	(149,201,452)	(297,534)	(149,498,986)	(297,461)	(149,796,446)	(297,387)
Pre-merger Utah	SG	(33,052,031)	(70,824)	(33,122,855)	(70,735)	(33,193,590)	(70,646)	(33,264,236)	(70,556)	(33,334,792)	(70,467)	(33,405,258)	(70,377)	(33,475,635)	(70,288)
Post-merger	SG-P	(207,224,503)	(1,204,270)	(208,428,773)	(1,246,802)	(209,675,575)	(1,289,334)	(210,964,909)	(1,288,649)	(212,253,558)	(1,288,086)	(213,541,644)	(1,288,368)	(214,830,012)	(1,288,529)
Post-merger	SG-U	(80,604,040)	(551,038)	(81,155,078)	(550,681)	(81,705,759)	(550,325)	(82,256,084)	(550,571)	(82,806,655)	(556,258)	(83,362,913)	(565,830)	(83,928,743)	(569,959)
Klamath - New Capital	SG-P	(58,864)	(23,546)	(82,410)	(23,546)	(105,955)	(23,546)	(129,501)	(23,546)	(153,047)	(23,546)	(176,592)	(23,546)	(200,138)	(23,546)
Total Hydro Plant		(468,950,023)	(2,147,504)	(471,097,528)	(2,189,517)	(473,287,045)	(2,231,530)	(475,518,575)	(2,230,928)	(477,749,504)	(2,235,890)	(479,985,394)	(2,245,581)	(482,230,975)	(2,249,709)
Other Production Plant:															
Pre-merger Utah	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG	(594,536,665)	(3,716,675)	(598,253,341)	(3,710,918)	(601,964,259)	(3,705,161)	(605,669,420)	(3,700,641)	(609,370,062)	(3,699,384)	(613,069,446)	(3,696,890)	(616,766,336)	(3,691,133)
Post-merger Wind	SG-W	36,138,082	(11,573,984)	24,564,098	(11,582,446)	12,981,651	(11,591,230)	1,390,421	(11,594,991)	(10,204,570)	(11,604,125)	(21,808,695)	(11,612,705)	(33,421,400)	(11,615,134)
Oregon Solar	OR	(24,042)	(3,985)	(28,027)	(3,985)	(32,012)	(3,985)	(35,996)	(3,985)	(39,981)	(3,985)	(43,966)	(3,985)	(47,951)	(3,985)
Post-merger	SG	(52,176,199)	(291,262)	(52,467,462)	(291,014)	(52,758,476)	(290,766)	(53,049,242)	(290,650)	(53,339,892)	(290,608)	(53,630,500)	(290,813)	(53,921,314)	(290,944)
Total Other Plant		(610,598,825)	(15,585,907)	(626,184,732)	(15,588,364)	(641,773,095)	(15,591,142)	(657,364,237)	(15,590,267)	(672,954,505)	(15,598,103)	(688,552,608)	(15,604,393)	(704,157,001)	(15,601,196)
Transmission Plant:															
Pre-merger Pacific	SG	(352,916,849)	(481,774)	(353,398,623)	(481,508)	(353,880,131)	(481,242)	(354,361,373)	(480,975)	(354,842,348)	(480,709)	(355,323,057)	(480,442)	(355,803,500)	(480,176)
Pre-merger Utah	SG	(424,488,583)	(499,812)	(424,988,395)	(499,327)	(425,487,722)	(498,841)	(425,986,563)	(498,356)	(426,484,918)	(497,870)	(426,982,788)	(497,384)	(427,480,173)	(496,899)
Post-merger	SG	(1,484,329,164)	(8,688,927)	(1,493,018,091)	(8,741,919)	(1,501,760,010)	(8,765,127)	(1,510,525,138)	(8,881,156)	(1,519,406,293)	(9,005,994)	(1,528,412,287)	(9,078,256)	(1,537,490,543)	(9,178,121)
Total Transmission Plant		(2,261,734,596)	(9,670,514)	(2,271,405,110)	(9,722,753)	(2,281,127,863)	(9,745,210)	(2,290,873,073)	(9,860,486)	(2,300,733,560)	(9,984,573)	(2,310,718,132)	(10,056,082)	(2,320,774,215)	(10,155,196)
Distribution Plant:															
California	CA	(156,964,357)	(636,360)	(157,600,717)	(640,392)	(158,241,109)	(644,466)	(158,885,575)	(650,261)	(159,535,836)	(660,846)	(160,196,682)	(670,922)	(160,867,604)	(675,926)
Oregon	OR	(1,167,167,496)	(2,146,840)	(1,169,314,336)	(2,157,557)	(1,171,471,894)	(2,168,878)	(1,173,640,772)	(2,178,481)	(1,175,819,253)	(2,190,111)	(1,178,009,363)	(2,205,713)	(1,180,215,077)	(2,219,557)
Washington	WA	(300,770,452)	(945,706)	(301,716,158)	(948,778)	(302,664,936)	(952,912)	(303,617,848)	(957,382)	(304,575,230)	(961,531)	(305,536,761)	(964,946)	(306,501,707)	(968,424)
Eastern Wyoming	WYP	(322,307,301)	(1,063,612)	(323,370,912)	(1,066,452)	(324,437,365)	(1,069,667)	(325,507,032)	(1,072,936)	(326,579,968)	(1,076,648)	(327,656,616)	(1,080,425)	(328,737,041)	(1,084,104)
Utah	UT	(1,181,418,448)	(5,215,812)	(1,186,634,260)	(5,252,356)	(1,191,886,616)	(5,292,585)	(1,197,179,201)	(5,354,485)	(1,202,533,686)	(5,418,529)	(1,207,952,215)	(5,464,012)	(1,213,416,227)	(5,510,879)
Idaho	ID	(164,168,496)	(387,105)	(164,555,601)	(389,359)	(164,944,960)	(392,070)	(165,337,030)	(405,489)	(165,742,519)	(418,981)	(166,161,500)	(421,708)	(166,583,207)	(424,504)
Western Wyoming	WYU	(69,577,620)	(292,262)	(69,869,882)	(292,162)	(70,162,044)	(292,061)	(70,454,104)	(291,960)	(70,746,064)	(291,859)	(71,037,924)	(291,758)	(71,329,682)	(291,657)
Total Distribution Plant		(3,362,374,169)	(10,687,697)	(3,373,061,867)	(10,747,056)	(3,383,808,922)	(10,812,640)	(3,394,621,563)	(10,910,994)	(3,405,532,557)	(11,018,505)	(3,416,551,061)	(11,099,484)	(3,427,650,545)	(11,175,052)
General Plant:															
California	CA	(8,265,739)	(26,070)	(8,291,809)	(25,985)	(8,317,794)	(25,899)	(8,343,693)	(25,817)	(8,369,510)	(25,749)	(8,395,259)	(25,702)	(8,420,961)	(25,652)
Oregon	OR	(92,826,695)	(250,778)	(93,077,473)	(249,997)	(93,327,470)	(249,257)	(93,576,726)	(248,673)	(93,825,399)	(248,426)	(94,073,825)	(248,663)	(94,322,488)	(248,736)
Washington	WA	(26,870,213)	(74,390)	(26,944,602)	(74,837)	(27,019,439)	(75,278)	(27,094,717)	(75,116)	(27,169,833)	(75,046)	(27,244,879)	(75,033)	(27,319,912)	(74,949)
Eastern Wyoming	WYP	(34,020,768)	(202,973)	(34,223,741)	(203,076)	(34,426,817)	(203,198)	(34,630,015)	(203,368)	(34,833,383)	(203,659)	(35,037,042)	(203,934)	(35,240,975)	(204,205)
Utah	UT	(118,932,424)	(709,521)	(119,641,945)	(709,950)	(120,351,895)	(710,489)	(121,062,384)	(711,347)	(121,773,731)	(712,959)	(122,486,690)	(714,461)	(123,201,151)	(715,957)
Idaho	ID	(24,296,197)	(132,834)	(24,429,032)	(132,941)	(24,561,972)	(133,062)	(24,695,035)	(133,226)	(24,828,261)	(133,492)	(24,961,753)	(133,744)	(25,095,497)	(133,995)
Western Wyoming	WYU	(8,193,953)	(45,961)	(8,239,914)	(45,919)	(8,285,833)	(45,877)	(8,331,710)	(45,834)	(8,377,544)	(45,792)	(8,423,336)	(45,750)	(8,469,086)	(45,708)
Pre-merger Pacific	SG	(413,312)	8,569	(404,743)	8,578	(396,165)	8,586	(387,579)	8,594	(378,985)	8,603	(370,382)	8,611	(361,771)	8,619
Pre-merger Utah	SG	(1,922,507)	24,348	(1,898,160)	24,375	(1,873,785)	24,402	(1,849,384)	24,429	(1,824,955)	24,455	(1,800,499)	24,482	(1,776,017)	24,509
Post-merger	SG	(148,276,015)	(768,226)	(149,044,242)	(766,478)	(149,810,720)	(764,729)	(150,575,449)	(762,981)	(151,338,430)	(761,232)	(152,099,663)	(759,498)	(152,859,160)	(757,763)
General Office	SO	(125,548,557)	(674,968)	(126,223,526)	(687,454)	(126,910,980)	(697,376)	(127,608,356)	(709,242)	(128,317,597)	(732,149)	(129,049,746)	(754,606)	(129,804,353)	(766,697)
General Office	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-
General Office	SG	(154,572)	(743)	(155,315)	(743)	(156,058)	(743)	(156,801)	(743)	(157,544)	(742)	(158,286)	(742)	(159,028)	(742)
Customer Service	CN	(6,016,657)	42,981	(5,973,676)	43,439	(5,930,238)	43,896	(5,886,341)	44,354	(5,841,987)	44,811	(5,797,176)	45,269	(5,751,907)	45,727
Fuel Related	SE	(1,845,073)	(6,518)	(1,851,592)	(6,485)	(1,858,077)	(6,452)	(1,864,528)	(6,418)	(1,870,947)	(6,385)	(1,877,332)	(6,352)	(1,883,684)	(6,319)
Total General Plant		(597,582,684)	(2,817,085)	(600,399,769)	(2,827,474)	(603,227,243)	(2,835,475)	(606,062,718)	(2,845,388)	(608,908,106)	(2,867,762)	(611,775,868)	(2,890,121)	(614,665,990)	(2,901,865)
Mining Plant:															
Coal Mine	SE	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Mining Plant		-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Depreciation Reserve		(12,556,260,328)	(71,704,069)	(12,627,964,396)	(71,870,815)	(12,699,835,211)	(72,165,927)	(12,772,001,138)	(72,530,175)	(12,844,531,313)	(72,801,745)	(12,917,333,058)	(72,997,793)	(12,990,330,851)	(73,177,270)

PacifiCorp
Oregon General Rate Case - December 2025
Jun 2023 - December 2024 Depreciation & Amortization Reserve

Description	Factor	Adjusted Reserve Balance Jan 2024	Adjustments	Adjusted Reserve Balance Feb 2024	Adjustments	Adjusted Reserve Balance Mar 2024	Adjustments	Adjusted Reserve Balance Apr 2024	Adjustments	Adjusted Reserve Balance May 2024	Adjustments	Adjusted Reserve Balance Jun 2024	Adjustments	Adjusted Reserve Balance Jul 2024	Adjustments
AMORTIZATION RESERVE															
Intangible Plant:															
California	CA	68	10	77	10	87	10	97	10	106	10	116	10	126	10
Customer Service	CN	(194,123,755)	(1,169,960)	(195,293,715)	(1,169,185)	(196,462,900)	(1,168,409)	(197,631,309)	(1,167,634)	(198,798,943)	(1,166,858)	(199,965,801)	(1,166,083)	(201,131,884)	(1,165,307)
Idaho	ID	(999,799)	29	(999,770)	29	(999,741)	29	(999,712)	29	(999,683)	29	(999,655)	29	(999,626)	29
Pre-merger Utah	SG	(414,768)	1,051	(413,717)	1,055	(412,661)	1,060	(411,601)	1,064	(410,537)	1,069	(409,468)	1,073	(408,395)	1,078
Oregon	OR	(153,555)	(533)	(154,089)	(533)	(154,621)	(533)	(155,154)	(533)	(155,687)	(533)	(156,220)	(533)	(156,753)	(533)
Fuel Related	SE	(4,793)	123	(4,670)	127	(4,543)	131	(4,412)	135	(4,277)	139	(4,137)	143	(3,994)	147
Post-merger	SG	(111,895,253)	(441,669)	(112,336,922)	(441,549)	(112,778,471)	(441,429)	(113,219,899)	(441,308)	(113,661,208)	(441,188)	(114,102,396)	(441,068)	(114,543,464)	(440,948)
Hydro Relicensing	SG-P	(47,359,318)	(218,818)	(47,578,136)	(218,808)	(47,796,944)	(218,798)	(48,015,741)	(218,788)	(48,234,529)	(218,778)	(48,453,306)	(218,767)	(48,672,074)	(218,757)
Hydro Relicensing	SG-U	(6,487,058)	(11,720)	(6,498,777)	(11,679)	(6,510,457)	(11,639)	(6,522,096)	(11,599)	(6,533,695)	(11,559)	(6,545,255)	(11,519)	(6,556,774)	(11,479)
General Office	SO	(380,129,254)	(2,385,622)	(382,514,875)	(2,395,775)	(384,910,651)	(2,424,801)	(387,335,452)	(2,444,203)	(389,779,655)	(2,511,245)	(392,290,900)	(2,576,039)	(394,866,939)	(2,580,896)
Pre-merger Pacific	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Utah	UT	(264,148)	(7,833)	(271,981)	(7,833)	(279,813)	(7,832)	(287,646)	(7,832)	(295,477)	(7,832)	(303,309)	(7,831)	(311,140)	(7,831)
Washington	WA	(431)	(10)	(442)	(10)	(452)	(10)	(462)	(10)	(473)	(10)	(483)	(10)	(493)	(10)
Eastern Wyoming	WYP	(328,771)	(3,035)	(331,805)	(3,032)	(334,837)	(3,029)	(337,866)	(3,026)	(340,893)	(3,024)	(343,916)	(3,021)	(346,937)	(3,018)
Western Wyoming	WYU	-	-	-	-	-	-	-	-	-	-	-	-	-	-
General Office	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Intangible Plant		(742,160,834)	(4,237,987)	(746,398,821)	(4,247,182)	(750,646,003)	(4,275,251)	(754,921,255)	(4,293,695)	(759,214,950)	(4,359,780)	(763,574,730)	(4,423,616)	(767,998,346)	(4,427,516)
Hydro Production Plant:															
Pre-merger Pacific	SG	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG-P	(3,947,844)	(26,156)	(3,974,000)	(26,156)	(4,000,157)	(26,156)	(4,026,313)	(26,156)	(4,052,470)	(26,156)	(4,078,626)	(26,156)	(4,104,783)	(26,156)
Post-merger	SG-U	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Hydro Plant		(3,947,844)	(26,156)	(3,974,000)	(26,156)	(4,000,157)	(26,156)	(4,026,313)	(26,156)	(4,052,470)	(26,156)	(4,078,626)	(26,156)	(4,104,783)	(26,156)
Other Production Plant:															
Oregon	OR	(133,355)	(5,887)	(139,242)	(5,887)	(145,129)	(5,887)	(151,015)	(5,887)	(156,902)	(5,887)	(162,789)	(5,887)	(168,676)	(5,887)
Total Other Plant		(133,355)	(5,887)	(139,242)	(5,887)	(145,129)	(5,887)	(151,015)	(5,887)	(156,902)	(5,887)	(162,789)	(5,887)	(168,676)	(5,887)
General Plant:															
California	CA	(506,016)	(22)	(506,039)	(22)	(506,061)	(22)	(506,083)	(22)	(506,106)	(22)	(506,128)	(22)	(506,151)	(22)
General Office	CN	-	-	-	-	-	-	-	-	-	-	-	-	-	-
General Office	ID	(333,771)	-	(333,771)	-	(333,771)	-	(333,771)	-	(333,771)	-	(333,771)	-	(333,771)	-
Oregon	OR	(5,145,704)	(11,632)	(5,157,336)	(11,632)	(5,168,967)	(11,632)	(5,180,599)	(11,632)	(5,192,230)	(11,632)	(5,203,862)	(11,632)	(5,215,494)	(11,632)
General Office	SO	(1,466,931)	(3,447)	(1,470,378)	(3,447)	(1,473,825)	(3,447)	(1,477,272)	(3,447)	(1,480,719)	(3,447)	(1,484,166)	(3,447)	(1,487,613)	(3,447)
Utah	UT	(33,127)	-	(33,127)	-	(33,127)	-	(33,127)	-	(33,127)	-	(33,127)	-	(33,127)	-
Washington	WA	(2,111,927)	(8,988)	(2,120,916)	(8,988)	(2,129,904)	(8,988)	(2,138,893)	(8,988)	(2,147,881)	(8,988)	(2,156,870)	(8,988)	(2,165,858)	(8,988)
Eastern Wyoming	WYP	(4,743,517)	(14,430)	(4,757,947)	(14,430)	(4,772,377)	(14,430)	(4,786,808)	(14,430)	(4,801,238)	(14,430)	(4,815,668)	(14,430)	(4,830,098)	(14,430)
Western Wyoming	WYU	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total General Plant		(14,340,994)	(38,520)	(14,379,513)	(38,520)	(14,418,033)	(38,520)	(14,456,553)	(38,520)	(14,495,072)	(38,520)	(14,533,592)	(38,520)	(14,572,111)	(38,520)
Total Amortization Reserve		(760,583,027)	(4,308,550)	(764,891,576)	(4,317,745)	(769,209,322)	(4,345,814)	(773,555,136)	(4,364,258)	(777,919,394)	(4,430,343)	(782,349,737)	(4,494,179)	(786,843,916)	(4,498,079)
Total Depreciation & Amortization Reserve		(13,316,843,354)	(76,012,618)	(13,392,855,973)	(76,188,560)	(13,469,044,533)	(76,511,741)	(13,545,556,274)	(76,894,433)	(13,622,450,707)	(77,232,088)	(13,699,682,795)	(77,491,972)	(13,777,174,767)	(77,675,349)

PacifiCorp
Oregon General Rate Case - December 2025
Jun 2023 - December 2024 Depreciation & Amortization Reserve

Description	Factor	Adjusted Reserve Balance Aug 2024	Adjustments	Adjusted Reserve Balance Sep 2024	Adjustments	Adjusted Reserve Balance Oct 2024	Adjustments	Adjusted Reserve Balance Nov 2024	Adjustments	Adjusted Reserve Balance Dec 2024	CY 2024 YE Balance	Incremental Reserve For Annualized Depreciation	CY 2024 Adjusted Reserve Year End Balance
DEPRECIATION RESERVE													
Steam Production Plant:													
Pre-merger Pacific	SG	(880,805,512)	(3,986,310)	(884,791,822)	(3,985,127)	(888,776,949)	(3,983,945)	(892,760,894)	(3,982,762)	(896,743,657)	(896,743,657)	85,141	(896,658,516)
Pre-merger Utah	SG	(827,101,371)	(4,126,758)	(831,228,129)	(4,125,737)	(835,353,866)	(4,124,715)	(839,478,581)	(4,123,694)	(843,602,275)	(843,602,275)	73,543	(843,528,732)
Post-merger	SG	(3,749,018,940)	(22,804,317)	(3,771,823,256)	(22,793,350)	(3,794,616,607)	(22,786,998)	(3,817,403,605)	(22,814,782)	(3,840,218,387)	(3,840,218,387)	(1,490,785)	(3,841,709,172)
Renewable - Blundell	SG	(14,975,134)	(159,844)	(15,134,978)	(159,915)	(15,294,893)	(159,985)	(15,454,878)	(160,056)	(15,614,933)	(15,614,933)	(8,059)	(15,622,993)
Carbon	SG	-	-	-	-	-	-	-	-	-	-	-	-
Pollution Control Equipment	SG	(45,422)	(6,685)	(52,107)	(6,685)	(58,792)	(6,685)	(65,477)	(6,866)	(72,343)	(72,343)	(19,419)	(91,762)
Post-merger	SG	-	-	-	-	-	-	-	-	-	-	-	-
Total Steam Plant		(5,471,946,378)	(31,083,914)	(5,503,030,292)	(31,070,814)	(5,534,101,107)	(31,062,329)	(5,565,163,435)	(31,088,160)	(5,596,251,596)	(5,596,251,596)	(1,359,579)	(5,597,611,175)
Hydro Production Plant:													
Pre-merger Pacific	SG	(150,093,834)	(297,314)	(150,391,148)	(297,241)	(150,688,389)	(297,168)	(150,985,557)	(297,095)	(151,282,652)	(151,282,652)	5,266	(151,277,386)
Pre-merger Utah	SG	(33,545,923)	(70,198)	(33,616,121)	(70,109)	(33,686,230)	(70,019)	(33,756,250)	(69,930)	(33,826,180)	(33,826,180)	6,441	(33,819,739)
Post-merger	SG-P	(216,118,542)	(1,301,692)	(217,420,234)	(1,332,876)	(218,753,110)	(1,354,111)	(220,107,221)	(1,365,705)	(221,472,926)	(221,472,926)	(1,031,538)	(222,504,464)
Post-merger	SG-U	(84,498,702)	(569,451)	(85,068,152)	(568,942)	(85,637,095)	(594,866)	(86,231,961)	(634,910)	(86,866,871)	(86,866,871)	(970,923)	(87,837,794)
Klamath - New Capital	SG-P	(223,684)	(23,546)	(247,229)	(23,546)	(270,775)	(23,546)	(294,320)	(23,546)	(317,866)	(317,866)	-	(317,866)
Total Hydro Plant		(484,480,684)	(2,262,201)	(486,742,885)	(2,292,714)	(489,035,599)	(2,339,710)	(491,375,309)	(2,391,185)	(493,766,494)	(493,766,494)	(1,990,755)	(495,757,249)
Other Production Plant:													
Pre-merger Utah	SG	-	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG	(620,457,470)	(3,685,376)	(624,142,846)	(3,679,619)	(627,822,465)	(3,673,862)	(631,496,327)	(3,670,984)	(635,167,311)	(635,167,311)	301,265	(634,866,047)
Post-merger Wind	SG-W	(45,036,534)	(11,622,685)	(56,659,219)	(11,630,344)	(68,289,562)	(11,632,971)	(79,922,534)	(11,642,994)	(91,565,528)	(91,565,528)	(546,891)	(92,112,420)
Oregon Solar	OR	(51,936)	(3,985)	(55,920)	(3,985)	(59,905)	(3,985)	(63,890)	(4,550)	(68,439)	(68,439)	(12,991)	(81,430)
Post-merger	SG	(54,212,257)	(290,696)	(54,502,953)	(290,448)	(54,793,400)	(290,200)	(55,083,600)	(289,952)	(55,373,552)	(55,373,552)	10,932	(55,362,620)
Total Other Plant		(719,758,196)	(15,602,742)	(735,360,938)	(15,604,395)	(750,965,333)	(15,601,018)	(766,566,351)	(15,608,480)	(782,174,830)	(782,174,830)	(247,686)	(782,422,516)
Transmission Plant:													
Pre-merger Pacific	SG	(356,283,676)	(479,910)	(356,763,585)	(479,643)	(357,243,228)	(479,377)	(357,722,605)	(479,110)	(358,201,715)	(358,201,715)	19,182	(358,182,534)
Pre-merger Utah	SG	(427,977,071)	(496,413)	(428,473,485)	(495,928)	(428,969,413)	(495,442)	(429,464,855)	(494,957)	(429,959,811)	(429,959,811)	34,959	(429,924,852)
Post-merger	SG	(1,546,668,663)	(9,360,513)	(1,556,029,176)	(9,531,417)	(1,565,560,593)	(11,235,444)	(1,576,796,037)	(12,925,237)	(1,589,721,274)	(1,589,721,274)	(41,362,287)	(1,631,083,561)
Total Transmission Plant		(2,330,929,410)	(10,336,836)	(2,341,266,246)	(10,506,988)	(2,351,773,234)	(12,210,263)	(2,363,983,497)	(13,899,304)	(2,377,882,801)	(2,377,882,801)	(41,308,146)	(2,419,190,946)
Distribution Plant:													
California	CA	(161,543,530)	(676,953)	(162,220,483)	(679,124)	(162,899,607)	(682,293)	(163,581,900)	(817,737)	(164,399,637)	(164,399,637)	(3,350,787)	(167,750,424)
Oregon	OR	(1,182,434,634)	(2,226,793)	(1,184,661,427)	(2,231,400)	(1,186,892,827)	(2,243,574)	(1,189,136,401)	(2,256,810)	(1,191,393,211)	(1,191,393,211)	(747,577)	(1,192,140,788)
Washington	WA	(307,470,131)	(970,847)	(308,440,978)	(972,441)	(309,413,420)	(976,658)	(310,390,078)	(992,964)	(311,383,042)	(311,383,042)	(512,213)	(311,895,255)
Eastern Wyoming	WYP	(329,821,145)	(1,088,006)	(330,909,151)	(1,091,471)	(332,000,622)	(1,094,400)	(333,095,022)	(1,105,874)	(334,200,896)	(334,200,896)	(436,445)	(334,637,341)
Utah	UT	(1,218,927,106)	(5,578,179)	(1,224,505,285)	(5,637,917)	(1,230,143,202)	(5,680,602)	(1,235,823,804)	(5,757,897)	(1,241,581,701)	(1,241,581,701)	(4,375,031)	(1,245,956,733)
Idaho	ID	(167,007,712)	(429,860)	(167,437,572)	(434,967)	(167,872,538)	(437,379)	(168,309,918)	(439,632)	(168,749,549)	(168,749,549)	(322,424)	(169,071,974)
Western Wyoming	WYU	(71,621,339)	(291,557)	(71,912,896)	(291,456)	(72,204,352)	(291,355)	(72,495,707)	(291,254)	(72,786,961)	(72,786,961)	7,260	(72,779,701)
Total Distribution Plant		(3,438,825,598)	(11,262,194)	(3,450,087,792)	(11,338,777)	(3,461,426,568)	(11,406,261)	(3,472,832,829)	(11,662,168)	(3,484,494,997)	(3,484,494,997)	(9,737,218)	(3,494,232,215)
General Plant:													
California	CA	(8,446,613)	(25,598)	(8,472,210)	(25,568)	(8,497,778)	(25,532)	(8,523,310)	(26,733)	(8,550,042)	(8,550,042)	(25,052)	(8,575,095)
Oregon	OR	(94,571,224)	(248,748)	(94,819,971)	(249,437)	(95,069,409)	(249,924)	(95,319,332)	(298,565)	(95,617,897)	(95,617,897)	(1,123,462)	(96,741,359)
Washington	WA	(27,394,861)	(74,856)	(27,469,717)	(74,834)	(27,544,551)	(74,787)	(27,619,338)	(77,455)	(27,696,793)	(27,696,793)	(60,896)	(27,757,690)
Eastern Wyoming	WYP	(35,445,180)	(204,493)	(35,649,673)	(204,779)	(35,854,452)	(206,007)	(36,060,458)	(208,354)	(36,268,812)	(36,268,812)	(64,985)	(36,333,798)
Utah	UT	(123,917,108)	(717,563)	(124,634,671)	(719,167)	(125,353,837)	(721,728)	(126,075,565)	(725,358)	(126,800,923)	(126,800,923)	(152,442)	(126,953,365)
Idaho	ID	(25,229,492)	(134,261)	(25,363,753)	(134,528)	(25,498,281)	(134,923)	(25,633,204)	(135,465)	(25,768,669)	(25,768,669)	(24,171)	(25,792,840)
Western Wyoming	WYU	(8,514,793)	(45,665)	(8,560,459)	(45,623)	(8,606,082)	(45,581)	(8,651,663)	(45,539)	(8,697,201)	(8,697,201)	3,041	(8,694,160)
Pre-merger Pacific	SG	(353,152)	8,628	(344,524)	8,636	(335,889)	8,644	(327,244)	8,652	(318,592)	(318,592)	597	(317,995)
Pre-merger Utah	SG	(1,751,508)	24,536	(1,726,971)	24,563	(1,702,408)	24,590	(1,677,818)	24,617	(1,653,200)	(1,653,200)	1,941	(1,651,259)
Post-merger	SG	(153,616,923)	(756,014)	(154,372,937)	(754,266)	(155,127,203)	(752,594)	(155,879,797)	(750,929)	(156,630,726)	(156,630,726)	123,941	(156,506,785)
General Office	SO	(130,571,049)	(777,503)	(131,348,553)	(790,291)	(132,138,844)	(802,023)	(132,940,867)	(859,382)	(133,800,249)	(133,800,249)	(2,029,594)	(135,829,842)
General Office	SG	-	-	-	-	-	-	-	-	-	-	-	-
General Office	SG	(159,770)	(742)	(160,511)	(741)	(161,253)	(741)	(161,994)	(741)	(162,735)	(162,735)	17	(162,717)
Customer Service	CN	(5,706,180)	46,184	(5,659,996)	46,642	(5,613,354)	47,099	(5,566,255)	47,557	(5,518,697)	(5,518,697)	32,947	(5,485,751)
Fuel Related	SE	(1,890,002)	(6,285)	(1,896,287)	(6,252)	(1,902,539)	(6,219)	(1,908,758)	(6,185)	(1,914,943)	(1,914,943)	2,397	(1,912,546)
Total General Plant		(617,567,855)	(2,912,379)	(620,480,234)	(2,925,644)	(623,405,878)	(2,939,725)	(626,345,603)	(3,053,879)	(629,399,481)	(629,399,481)	(3,315,721)	(632,715,203)
Mining Plant:													
Coal Mine	SE	-	-	-	-	-	-	-	-	-	-	-	-
Total Mining Plant		-	-	-	-	-	-	-	-	-	-	-	-
Total Depreciation Reserve		(13,063,508,121)	(73,460,266)	(13,136,968,387)	(73,739,332)	(13,210,707,719)	(75,559,305)	(13,286,267,024)	(77,703,175)	(13,363,970,200)	(13,363,970,200)	(57,959,105)	(13,421,929,304)

PacifiCorp
Oregon General Rate Case - December 2025
Jun 2023 - December 2024 Depreciation & Amortization Reserve

Description	Factor	Adjusted Reserve Balance Aug 2024	Adjustments	Adjusted Reserve Balance Sep 2024	Adjustments	Adjusted Reserve Balance Oct 2024	Adjustments	Adjusted Reserve Balance Nov 2024	Adjustments	Adjusted Reserve Balance Dec 2024	CY 2024 YE Balance	Incremental Reserve For Annualized Depreciation	CY 2024 Adjusted Reserve Year End Balance
AMORTIZATION RESERVE													
Intangible Plant:													
California	CA	135	10	145	10	155	10	164	10	174	174	-	174
Customer Service	CN	(202,297,191)	(1,164,532)	(203,461,723)	(1,163,757)	(204,625,480)	(1,162,981)	(205,788,461)	(1,162,206)	(206,950,667)	(206,950,667)	55,831	(206,894,836)
Idaho	ID	(999,597)	29	(999,568)	29	(999,540)	29	(999,511)	29	(999,482)	(999,482)	-	(999,482)
Pre-merger Utah	SG	(407,317)	1,082	(406,235)	1,087	(405,148)	1,091	(404,056)	1,096	(402,961)	(402,961)	322	(402,639)
Oregon	OR	(157,285)	(532)	(157,818)	(532)	(158,350)	(532)	(158,882)	(532)	(159,414)	(159,414)	6	(159,409)
Fuel Related	SE	(3,846)	151	(3,695)	156	(3,539)	160	(3,380)	164	(3,216)	(3,216)	293	(2,923)
Post-merger	SG	(114,984,412)	(440,828)	(115,425,240)	(440,708)	(115,865,948)	(440,588)	(116,306,535)	(440,468)	(116,747,003)	(116,747,003)	8,650	(116,738,353)
Hydro Relicensing	SG-P	(48,890,831)	(218,747)	(49,109,579)	(218,737)	(49,328,316)	(218,727)	(49,547,043)	(218,717)	(49,765,760)	(49,765,760)	726	(49,765,034)
Hydro Relicensing	SG-U	(6,568,252)	(11,439)	(6,579,691)	(11,399)	(6,591,090)	(11,359)	(6,602,449)	(11,319)	(6,613,767)	(6,613,767)	2,887	(6,610,880)
General Office	SO	(397,447,835)	(3,075,243)	(400,523,077)	(3,562,081)	(404,085,158)	(3,563,595)	(407,648,753)	(3,591,325)	(411,240,078)	(411,240,078)	(9,896,044)	(421,136,121)
Pre-merger Pacific	SG	-	-	-	-	-	-	-	-	-	-	-	-
Utah	UT	(318,971)	(7,831)	(326,802)	(7,830)	(334,632)	(7,830)	(342,462)	(7,830)	(350,291)	(350,291)	23	(350,268)
Washington	WA	(504)	(10)	(514)	(10)	(525)	(10)	(535)	(10)	(545)	(545)	-	(545)
Eastern Wyoming	WYP	(349,955)	(3,015)	(352,970)	(3,012)	(355,982)	(3,010)	(358,992)	(3,007)	(361,999)	(361,999)	201	(361,798)
Western Wyoming	WYU	-	-	-	-	-	-	-	-	-	-	-	-
General Office	SG	-	-	-	-	-	-	-	-	-	-	-	-
Total Intangible Plant		(772,425,862)	(4,920,905)	(777,346,767)	(5,406,786)	(782,753,553)	(5,407,342)	(788,160,895)	(5,434,115)	(793,595,010)	(793,595,010)	(9,827,105)	(803,422,114)
Hydro Production Plant:													
Pre-merger Pacific	SG	-	-	-	-	-	-	-	-	-	-	-	-
Post-merger	SG-P	(4,130,939)	(26,156)	(4,157,096)	(26,156)	(4,183,252)	(26,156)	(4,209,409)	(26,156)	(4,235,565)	(4,235,565)	-	(4,235,565)
Post-merger	SG-U	-	-	-	-	-	-	-	-	-	-	-	-
Total Hydro Plant		(4,130,939)	(26,156)	(4,157,096)	(26,156)	(4,183,252)	(26,156)	(4,209,409)	(26,156)	(4,235,565)	(4,235,565)	-	(4,235,565)
Other Production Plant:													
Oregon	OR	(174,562)	(5,887)	(180,449)	(5,887)	(186,336)	(5,887)	(192,223)	(5,887)	(198,109)	(198,109)	-	(198,109)
Total Other Plant		(174,562)	(5,887)	(180,449)	(5,887)	(186,336)	(5,887)	(192,223)	(5,887)	(198,109)	(198,109)	-	(198,109)
General Plant:													
California	CA	(506,173)	(22)	(506,195)	(22)	(506,218)	(22)	(506,240)	(22)	(506,263)	(506,263)	-	(506,263)
General Office	CN	-	-	-	-	-	-	-	-	-	-	-	-
General Office	ID	(333,771)	-	(333,771)	-	(333,771)	-	(333,771)	-	(333,771)	(333,771)	-	(333,771)
Oregon	OR	(5,227,125)	(11,632)	(5,238,757)	(11,632)	(5,250,388)	(11,632)	(5,262,020)	(11,632)	(5,273,651)	(5,273,651)	-	(5,273,651)
General Office	SO	(1,491,060)	(3,447)	(1,494,507)	(3,447)	(1,497,954)	(3,447)	(1,501,401)	(3,447)	(1,504,848)	(1,504,848)	-	(1,504,848)
Utah	UT	(33,127)	-	(33,127)	-	(33,127)	-	(33,127)	-	(33,127)	(33,127)	-	(33,127)
Washington	WA	(2,174,846)	(8,988)	(2,183,835)	(8,988)	(2,192,823)	(8,988)	(2,201,812)	(8,988)	(2,210,800)	(2,210,800)	-	(2,210,800)
Eastern Wyoming	WYP	(4,844,529)	(14,430)	(4,858,959)	(14,430)	(4,873,389)	(14,430)	(4,887,820)	(14,430)	(4,902,250)	(4,902,250)	-	(4,902,250)
Western Wyoming	WYU	-	-	-	-	-	-	-	-	-	-	-	-
Total General Plant		(14,610,631)	(38,520)	(14,649,151)	(38,520)	(14,687,670)	(38,520)	(14,726,190)	(38,520)	(14,764,710)	(14,764,710)	-	(14,764,710)
Total Amortization Reserve		(791,341,995)	(4,991,468)	(796,333,463)	(5,477,349)	(801,810,811)	(5,477,905)	(807,288,716)	(5,504,677)	(812,793,394)	(812,793,394)	(9,827,105)	(822,620,498)
Total Depreciation & Amortization Reserve		(13,854,850,116)	(78,451,734)	(13,933,301,850)	(79,216,681)	(14,012,518,531)	(81,037,210)	(14,093,555,741)	(83,207,853)	(14,176,763,593)	(14,176,763,593)	(67,786,209)	**(14,244,549,803)**
													Ref. 6.2.3

PacifiCorp
Oregon General Rate Case - December 2025
Depreciation & Amortization Reserves
Coal Depreciable Life Update from UE-399

	PROPOSED END OF DEPRECIABLE	AS OF DEC 31, 2022			ACCEL. DEPR. RATES		COMPOSITE REMAINING	EXISTING RATES		
	LIFE	ORIGINAL COST	ACCUM. RESERVES	FUTURE ACCURALS	ANNUAL AMOUNT	ACCRUAL RATE	LIFE	CURRENT RATE[1]	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. 6.2.1

Note 1 - Current rates are per approved 2018 Depreciation Study.

Depreciation Reserve Impact	Per Month	Balance
January-23	259,082	259,082
February-23	259,082	518,164
March-23	259,082	777,246
April-23	259,082	1,036,328
May-23	259,082	1,295,410
June-23	259,082	1,554,492
July-23	259,082	1,813,574
August-23	259,082	2,072,656
September-23	259,082	2,331,738
October-23	259,082	2,590,820
November-23	259,082	2,849,902
December-23	259,082	3,108,984
January-24	259,082	3,368,066
February-24	259,082	3,627,148
March-24	259,082	3,886,230
April-24	259,082	4,145,312
May-24	259,082	4,404,395
June-24	259,082	4,663,477
July-24	259,082	4,922,559
August-24	259,082	5,181,641
September-24	259,082	5,440,723
October-24	259,082	5,699,805
November-24	259,082	5,958,887
December-24	259,082	**6,217,969**
		Ref. 6.2.1

PacifiCorp
Oregon General Rate Case - December 2025
Oregon Coal-Fired Steam Plant Depreciation

<u>Depreciation Reserve Adjustment</u>

	Total Company	Factor
Adjustment to June 2023 Reserve:		
Steam Plant Accumulated Depreciation	**(1,106,576,512)**	**SG**

<u>Depreciation Reserve Adjustment By Plant</u>

Plant	Factor	Adjustment to Expense (Yr Ended Jun 2023)
NAUGHTON	SG	(68,887,120)
HUNTINGTON	SG	(123,005,957)
HUNTER	SG	(251,911,355)
CRAIG	SG	(12,881,661)
HAYDEN	SG	(34,018,248)
COLSTRIP	SG	(3,639,231)
DAVE JOHNSTON	SG	(104,755,799)
JIM BRIDGER	SG	(403,524,362)
WYODAK	SG	(103,952,780)
		(1,106,576,512)

This is the increase in the depreciation reserve June 2023 starting balance in adjustment 6.2. This reflects the increase from January 2008 to June 2023 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 - 2025
Hydro Decommissioning
Spending, Accruals, and Balances - East Side, West Side, and Total Resources

West Side	Spend	Accruals	Balance
July-22	2,417	60,700	(6,148,439)
August-22	15,895	60,700	(6,071,845)
September-22	1,693	60,700	(6,009,452)
October-22	617	60,700	(5,948,135)
November-22	198,521	60,700	(5,688,915)
December-22	720,470	60,700	(4,907,745)
January-23	(5,097)	60,700	(4,852,143)
February-23	45,156	60,700	(4,746,287)
March-23	786	60,700	(4,684,801)
April-23	1,519	60,700	(4,622,582)
May-23	-	60,700	(4,561,883)
June-23	-	60,700	(4,501,183)

East Side	Spend	Accruals	Balance
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)
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)

Total Resources	Spend	Accruals	Balance
July-22	2,417	37,344	(6,741,545)
August-22	15,895	37,344	(6,688,306)
September-22	1,693	37,344	(6,649,269)
October-22	617	37,344	(6,611,309)
November-22	198,521	37,344	(6,375,444)
December-22	720,470	37,344	(5,617,630)
January-23	(5,097)	37,344	(5,585,384)
February-23	45,156	37,344	(5,502,884)
March-23	786	37,344	(5,464,754)
April-23	1,519	37,344	(5,425,892)
May-23	-	37,344	(5,388,548)
June-23	-	37,344	(5,351,204)

West Side	Spend	Accruals	Balance
December-23	-	-	(4,135,803)
January-24	-	60,700	(4,075,103)
February-24	-	60,700	(4,014,403)
March-24	-	60,700	(3,953,704)
April-24	-	60,700	(3,893,004)
May-24	-	60,700	(3,832,304)
June-24	-	60,700	(3,771,604)
July-24	-	60,700	(3,710,905)
August-24	-	60,700	(3,650,205)
September-24	-	60,700	(3,589,505)
October-24	-	60,700	(3,528,806)
November-24	-	60,700	(3,468,106)
December-24	-	60,700	(3,407,406)

East Side	Spend	Accruals	Balance
December-23	-	-	(990,157)
January-24	-	(23,356)	(1,013,513)
February-24	-	(23,356)	(1,036,869)
March-24	-	(23,356)	(1,060,225)
April-24	-	(23,356)	(1,083,581)
May-24	-	(23,356)	(1,106,937)
June-24	-	(23,356)	(1,130,293)
July-24	-	(23,356)	(1,153,649)
August-24	-	(23,356)	(1,177,005)
September-24	-	(23,356)	(1,200,361)
October-24	-	(23,356)	(1,223,717)
November-24	-	(23,356)	(1,247,073)
December-24	-	(23,356)	(1,270,428)

Total Resources	Spend	Accruals	Balance
December-23	-	-	(5,125,960)
January-24	-	37,344	(5,088,616)
February-24	-	37,344	(5,051,272)
March-24	-	37,344	(5,013,928)
April-24	-	37,344	(4,976,585)
May-24	-	37,344	(4,939,241)
June-24	-	37,344	(4,901,897)
July-24	-	37,344	(4,864,553)
August-24	-	37,344	(4,827,210)
September-24	-	37,344	(4,789,866)
October-24	-	37,344	(4,752,522)
November-24	-	37,344	(4,715,178)
December-24	-	37,344	(4,677,835)

PacifiCorp
Oregon General Rate Case - December 2025
Repowering Buy Downs Adjustment

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Repowered Buy-Down	407	1	(6,748,553)	OR	Situs	(6,748,553)	6.3.1
Adjustment to Reserves:							
RAC buy-down reserves adj.	108OP	1	(179,821,190)	OR	Situs	(179,821,190)	6.3.2
Pro Forma RAC buy-down res. amort.	108OP	3	6,748,553	OR	Situs	6,748,553	6.3.2

Description of Adjustment:

This adjustment corrects the allocation of expenses recorded as a result of the buy-down in the base period for the repowered wind facilities, as well as brings 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 2025
Repowering Buy Downs Adjustment

Year	Account	Actual FERC Account	Revised FERC Account	Text	Booked Alloc.	Correct Alloc.	Amount	
2022	565243	4034000	4070000	Depr Adj - Dunlap OR Wind Buydown	NUTIL	OR	(896,328)	
2022	565243	4034000	4070000	Depr Adj - Foote Creek OR Wind Buydown	NUTIL	OR	(88,212)	
2022	565243	4034000	4070000	Depr Adj - Glenrock 1 OR Wind Buydown	NUTIL	OR	(679,667)	
2022	565243	4034000	4070000	Depr Adj - Glenrock 3 OR Wind Buydown	NUTIL	OR	(245,997)	
2022	565243	4034000	4070000	Depr Adj - Goodnoe Hills OR Wind Buydown	NUTIL	OR	(795,704)	
2022	565243	4034000	4070000	Depr Adj - High Plains OR Wind Buydown	NUTIL	OR	(888,503)	
2022	565243	4034000	4070000	Depr Adj - Leaning Juniper OR Wind Buydown	NUTIL	OR	(581,162)	
2022	565243	4034000	4070000	Depr Adj - Marengo 1 OR Wind Buydown	NUTIL	OR	(901,133)	
2022	565243	4034000	4070000	Depr Adj - Marengo 2 OR Wind Buydown	NUTIL	OR	(477,864)	
2022	565243	4034000	4070000	Depr Adj - McFadden Ridge OR Wind Buydown	NUTIL	OR	(226,774)	
2022	565243	4034000	4070000	Depr Adj - Seven Mile Hill 1 OR Wind Buydown	NUTIL	OR	(800,555)	
2022	565243	4034000	4070000	Depr Adj - Seven Mile Hill 2 OR Wind Buydown	NUTIL	OR	(166,655)	
							(6,748,553)	**Ref 6.3**

PacifiCorp
Oregon General Rate Case - December 2025
Repowering Buy-Downs Adjustment

Base Period Amortization

	Beginning Balance	Amortization Expense	Ending Balance		
Base Period Amortization					
January-22	(189,944,020)	(562,379)	(189,381,641)		
February-22	(189,381,641)	(562,379)	(188,819,261)		
March-22	(188,819,261)	(562,379)	(188,256,882)		
April-22	(188,256,882)	(562,379)	(187,694,502)		
May-22	(187,694,502)	(562,379)	(187,132,123)		
June-22	(187,132,123)	(562,379)	(186,569,744)		
July-22	(186,569,744)	(562,379)	(186,007,364)		
August-22	(186,007,364)	(562,379)	(185,444,985)		
September-22	(185,444,985)	(562,379)	(184,882,605)		
October-22	(184,882,605)	(562,379)	(184,320,226)		
November-22	(184,320,226)	(562,379)	(183,757,846)		
December-22	(183,757,846)	(562,379)	(183,195,467)		
January-23	(183,195,467)	(562,379)	(182,633,088)		
February-23	(182,633,088)	(562,379)	(182,070,708)		
March-23	(182,070,708)	(562,379)	(181,508,329)		
April-23	(181,508,329)	(562,379)	(180,945,949)		
May-23	(180,945,949)	(562,379)	(180,383,570)		
June-23	(180,383,570)	(562,379)	**(179,821,190)**	**Ref 6.3**	
		(6,748,553)	**Ref 6.3**		
Proforma Amortization					
December-23	(177,009,293)	(562,379)	(176,446,914)		
January-24	(176,446,914)	(562,379)	(175,884,534)		
February-24	(175,884,534)	(562,379)	(175,322,155)		
March-24	(175,322,155)	(562,379)	(174,759,776)		
April-24	(174,759,776)	(562,379)	(174,197,396)		
May-24	(174,197,396)	(562,379)	(173,635,017)		
June-24	(173,635,017)	(562,379)	(173,072,637)		
July-24	(173,072,637)	(562,379)	(172,510,258)		
August-24	(172,510,258)	(562,379)	(171,947,878)		
September-24	(171,947,878)	(562,379)	(171,385,499)		
October-24	(171,385,499)	(562,379)	(170,823,120)		
November-24	(170,823,120)	(562,379)	(170,260,740)		
December-24	(170,260,740)	(562,379)	(169,698,361)	**(173,072,637)**	**Ref 6.3**
		(6,748,553)	**Ref 6.3**		

Base Period Amortization Expense	(6,748,553)	Above
Pro Forma Amortization Expense	(6,748,553)	Above
Adjustment to Expense	**-**	
Base Period Accum. Amort.	(179,821,190)	Above
Pro Forma Accum. Amort.	(173,072,637)	Above
Adjustment to Accum.	**6,748,553**	**Ref 6.3**

PacifiCorp
Oregon General Rate Case - December 2025
Confidential Bridger Coal Reclamation Costs

Note: Please see Confidential Exhibit PAC/1707_CONF for redacted information.

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Bridger Reclamation Costs	501	3	[redacted]	SE	26.339%	[redacted]	6.4.1_REDACTED
Adjustment to Rate Base:							
Bridger Reclamation Costs	254	3	(8,088,788)	OR	Situs	(8,088,788)	6.4.1_REDACTED
Adjustment to Tax:							
Schedule M Adjustment	SCHMAT	3	[redacted]	SE	26.339%	[redacted]	6.4.1_REDACTED
Deferred Income Tax Expense	41110	3		SE	26.339%		6.4.1_REDACTED
Accumulated Def Inc Tax Balance	190	3	1,988,755	OR	Situs	1,988,755	6.4.1_REDACTED

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 and UE 399, 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 2025.

PacifiCorp
Oregon General Rate Case - December 2025
Confidential Bridger Coal Reclamation Costs

Note: Please see Confidential Exhibit PAC/1707_CONF for redacted information.

Annual Incremental Contribution for Reclamation	[redacted]	
Incremental Depreciation Expense Prior to Reclamation	[redacted]	
Years from 2021 to 2025	5	
Annual Incremental Depreciation Expense	[redacted]	
Currently Approved Annual Amount	[redacted]	**Ref 6.4_REDACTED**

	TOTAL COMPANY				
	501 **Mthly Accum.**	**SCHMAT** **Tax**	**41110** **Def Inc Tax Exp**	**254** **Reg. Liab.**	**190** **ADIT**
Jun-23	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Jul-23	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Aug-23	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Sep-23	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Oct-23	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Nov-23	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Dec-23	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Jan-24	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Feb-24	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mar-24	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Apr-24	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
May-24	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Jun-24	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Jul-24	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Aug-24	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Sep-24	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Oct-24	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Nov-24	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Dec-24	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Jan-25	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Feb-25	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mar-25	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Apr-25	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
May-25	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Jun-25	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Jul-25	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Aug-25	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Sep-25	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Oct-25	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Nov-25	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Dec-25	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Annual Total	[redacted]	[redacted]	[redacted]		
	Ref 6.4_REDACTED	**Ref 6.4_REDACTED**	**Ref 6.4_REDACTED**		
			13 Mo. Avg. - Total Company	[redacted]	[redacted]
			13 Mo. Avg. - Oregon Allocated	[redacted]	[redacted]
			EOP June 2023 Balance	[redacted]	[redacted]
			Adjustment	**(8,088,788)**	**1,988,755**
				Ref 6.4_REDACTED	**Ref 6.4_REDACTED**

*Oregon 2025 SE Factor 26.339%

Tab 7 - Taxes

PacifiCorp **Page 7.0.1**
Oregon General Rate Case – December 2025
Tax Adjustment Index

The following adjustments were used to arrive at the normalized levels of tax expenses. The Company's 12 months ended June 2023 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 TCJA EDIT Adjustment
7.8 Oregon Corporate Activity Tax & Metro BIT
7.9 AFUDC Equity

The tax impacts of the following adjustments are included within the adjustment itself:

- Insurance Expense, 4.5
- Bridger Coal Reclamation Costs, page 6.4
- 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 Post-retirement Plan Balances Removal, page 8.8
- Remove Rolling Hills, page 8.9
- Deer Creek Mine Adjustment, page 8.10
- Emissions Control Investment Adjustment, page 8.11
- Transmission Project Adjustment, page 8.12
- Cholla Unit 4 Retirement, page 8.13
- Carbon Plant Closure, page 8.15
- Removal of Wildfire Mitigation Capital Rate Base, page 8.16.1
- Wildfire Restoration Costs Deferral Amortization, page 8.18
- Aeolus Substation Settlement, page 8.19
- Klamath Regulatory Asset, page 8.20

The tax impacts of the following adjustment are largely included within adjustment 7.4 and 7.5, though some impacts are included in the adjustment listed below:

- Pro Forma Plant Additions 8.4
- Confidential New Wind Generation Capital Additions 8.17

PacifiCorp
Oregon General Rate Case - December 2025
Tab 7 Adjustment Summary

		7.2	7.3	7.4	7.5	7.6	7.7
	Total Adjustments	Property Tax Expense	Production Tax Credit	PowerTax ADIT Balance	Pro Forma Tax Balances	Wyoming Wind Generation Tax	TCJA EDIT Adjustment
1 Operating ReWenues:							
2 General Business ReWenues	-	-	-	-	-	-	-
3 Interdepartmental	-	-	-	-	-	-	-
4 Special Sales	-	-	-	-	-	-	-
5 Other Operating ReWenues	-	-	-	-	-	-	-
6 Total Operating ReWenues	-	-	-	-	-	-	-
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 SerWice & Info	-	-	-	-	-	-	-
17 Sales	-	-	-	-	-	-	-
18 AdministratiWe & General	-	-	-	-	-	-	-
19							
20 Total O&M Expenses	-	-	-	-	-	-	-
21							
22 Depreciation	-	-	-	-	-	-	-
23 Amortization	-	-	-	-	-	-	-
24 Taxes Other Than Income	19,252,152	12,584,453	-	-	-	512,698	-
25 Income Taxes - Federal	(28,534,545)	(2,524,229)	(12,405,644)	(5,273,602)	(15,181,020)	(102,839)	(116,830)
26 Income Taxes - State	(6,548,315)	(571,668)	436	(1,194,325)	(3,437,681)	(23,290)	(26,459)
27 Income Taxes - Def Net	18,161,605	-	-	(1,466,027)	18,778,459	-	849,173
28 InWestment Tax Credit Adj.	-	-	-	-	-	-	-
29 Misc ReWenue & Expense	-	-	-	-	-	-	-
30							
31 Total Operating Expenses:	2,330,897	9,488,557	(12,405,208)	(7,933,954)	159,759	386,570	705,885
32							
33 Operating ReW For Return:	(2,330,897)	(9,488,557)	12,405,208	7,933,954	(159,759)	(386,570)	(705,885)
34							
35 Rate Base:							
36 Electric Plant In SerWice	-	-	-	-	-	-	-
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	(473,620)	283,877	(371,137)	(193,506)	(557,031)	11,565	(4,287)
45 Weatherization Loans	-	-	-	-	-	-	-
46 Misc Rate Base	-	-	-	-	-	-	-
47							
48 Total Electric Plant:	(473,620)	283,877	(371,137)	(193,506)	(557,031)	11,565	(4,287)
49							
50 Rate Base Deductions:							
51 Accum ProW For Deprec	-	-	-	-	-	-	-
52 Accum ProW For Amort	-	-	-	-	-	-	-
53 Accum Def Income Tax	(34,395,710)	-	-	(24,770,649)	(2,425,074)	-	(7,199,987)
54 Unamortized ITC	4,716	-	-	-	4,716	-	-
55 Customer AdW For Const	-	-	-	-	-	-	-
56 Customer SerWice Deposits	-	-	-	-	-	-	-
57 Misc Rate Base Deductions	29,710,341	-	-	-	-	-	29,710,341
58							
59 Total Rate Base Deductions	(4,680,653)	-	-	(24,770,649)	(2,420,358)	-	22,510,354
60							
61 Total Rate Base:	(5,154,273)	283,877	(371,137)	(24,964,155)	(2,977,389)	11,565	22,506,067
62							
63 Return on Rate Base	-0.047%	-0.233%	0.305%	0.245%	0.002%	-0.010%	-0.063%
64							
65 Return on Equity	-0.094%	-0.467%	0.610%	0.491%	0.004%	-0.019%	-0.126%
66							
67 TAX CALCULATION:							
68 Operating ReWenue	(19,252,152)	(12,584,453)	-	-	-	(512,698)	-
69 Other Deductions	-	-	-	-	-	-	-
70 Interest (AFUDC)	(38,533,764)	-	-	-	-	-	-
71 Interest	(133,469)	7,351	(9,611)	(646,442)	(77,099)	299	582,791
72 Schedule "M" Additions	40,628,028	-	-	36,353,545	4,274,483	-	-
73 Schedule "M" Deductions	143,378,120	-	-	63,306,702	80,071,417	-	-
74 Income Before Tax	(83,335,010)	(12,591,804)	9,611	(26,306,715)	(75,719,836)	(512,998)	(582,791)
75							
76 State Income Taxes	(6,548,315)	(571,668)	436	(1,194,325)	(3,437,681)	(23,290)	(26,459)
77 Taxable Income	(76,786,695)	(12,020,136)	9,174	(25,112,390)	(72,282,155)	(489,708)	(556,332)
78							
79 Federal Income Taxes + Other	(28,534,545)	(2,524,229)	(12,405,644)	(5,273,602)	(15,181,020)	(102,839)	(116,830)
APPROXIMATE PRICE CHANGE	2,653,261	13,061,382	(17,076,271)	(13,549,872)	(97,091)	532,129	3,361,835

PacifiCorp
Oregon General Rate Case - December 202
Tab 7 Adjustment Summary

		7.8 Oregon Corporate Activity Tax & Metro BIT	7.9 AFUDC Equity
1	Operating ReWenues:		
2	General Business ReWenues	-	-
3	Interdepartmental	-	-
4	Special Sales	-	-
5	Other Operating ReWenues	-	-
6	Total Operating ReWenues	-	-
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 SerWice & Info	-	-
17	Sales	-	-
18	AdministratiWe & General	-	-
19			
20	Total O&M Expenses	-	-
21			
22	Depreciation	-	-
23	Amortization	-	-
24	Taxes Other Than Income	6,155,000	-
25	Income Taxes - Federal	(653,620)	7,723,238
26	Income Taxes - State	(3,044,429)	1,749,100
27	Income Taxes - Def Net	-	-
28	InWestment Tax Credit Adj.	-	-
29	Misc ReWenue & Expense	-	-
30			
31	Total Operating Expenses:	2,456,951	9,472,338
32			
33	Operating ReW For Return:	(2,456,951)	(9,472,338)
34			
35	Rate Base:		
36	Electric Plant In SerWice	-	-
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	73,507	283,392
45	Weatherization Loans	-	-
46	Misc Rate Base	-	-
47			
48	Total Electric Plant:	73,507	283,392
49			
50	Rate Base Deductions:		
51	Accum ProW For Deprec	-	-
52	Accum ProW For Amort	-	-
53	Accum Def Income Tax	-	-
54	Unamortized ITC	-	-
55	Customer AdW For Const	-	-
56	Customer SerWice Deposits	-	-
57	Misc Rate Base Deductions	-	-
58			
59	Total Rate Base Deductions	-	-
60			
61	Total Rate Base:	73,507	283,392
62			
63	Return on Rate Base	-0.061%	-0.233%
64			
65	Return on Equity	-0.121%	-0.467%
66			
67	TAX CALCULATION:		
68	Operating ReWenue	(6,155,000)	-
69	Other Deductions	-	-
70	Interest (AFUDC)	-	(38,533,764)
71	Interest	1,903	7,338
72	Schedule "M" Additions	-	-
73	Schedule "M" Deductions	-	-
74	Income Before Tax	(6,156,903)	38,526,426
75			
76	State Income Taxes	(3,044,429)	1,749,100
77	Taxable Income	(3,112,474)	36,777,326
78			
79	Federal Income Taxes + Other	(653,620)	7,723,238
	APPROXIMATE PRICE CHANGE	3,382,092	13,039,057

PacifiCorp
Oregon General Rate Case - December 2025
Interest True-Up

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Interest	427	3	12,844,562	OR	Situs	12,844,562	Below

Adjustment Detail:	**Total Company**		
Interest June 2023 - Unadjusted	449,151,688	124,420,851	2.15
Interest December 2025 - Normalized	512,559,451	137,265,413	Below
Adjustment:	63,407,763	12,844,562	

Normalized Rate Base	20,588,965,700	5,300,883,073	2.2
Other & Non-Regulated	(795,066,735)	-	
Adjusted Rate Base	19,793,898,966	5,300,883,073	2.2
Weighted Cost of Debt	2.589%	2.589%	2.1
Normalized Interest	512,559,451	137,265,413	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 2025
Property Tax Expense

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Taxes Other Than Income	408	3	45,886,015	GPS	27.425%	12,584,453	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 2025
Property Tax Expense

	FERC Account	G/L Account	Co. Code	Total	Ref
Property Tax Expense - 12 Months Ended June 2023	408.15	579000	1000	133,792,985	
Estimated Property Tax Expense - December 2025				179,679,000	
Incremental Adjustment to Property Tax Expense				**45,886,015**	**Ref. 7.2**

PacifiCorp
Oregon General Rate Case - December 2025
Production Tax Credit

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Tax:							
FED Renewable Energy Tax Credit	40910	1	196,377,610	SG	26.884%	52,794,465	7.3.1
FED Renewable Energy Tax Credit	40910	3	(242,529,591)	SG	26.884%	(65,202,036)	7.3.1

Description of Adjustment:

The Company is entitled to recognize a federal income tax credit as a result of placing renewable generating plants in service. The tax credit is based on the kilowatt-hours generated by a qualified facility during the facility's first ten years of service. This adjustment removes the base period Renewable Energy Tax credits and adds in the pro forma period Renewable Energy Tax credits which are reflected in the Company's Transition Adjustment Mechanism filings annually.

As described in the testimony of Ms. Sherona L. Cheung, this adjustment is included in the calculation of overall revenue requirement for computational purposes only; the Company is not requesting recovery of NPC and PTCs as part of the general rate case. NPC and PTCs are reflected in the Company's Transition Adjustment Mechanism filings annually.

PacifiCorp
Oregon General Rate Case - December 2025
Production Tax Credit

Description	Total Available KWh	In-Service Date	Total PTC Eligible KWh	Factor (inflated tax per unit)	Federal Income Tax Credit	Bonus Credit if applicable	Federal Income Tax Credit, with Bonus Credit	
Pro Forma Period - December 2025								
Wind/Geothermal								
Glenrock **[a]**	265,613,199	**9/24/2019**	244,364,143	0.030	7,330,924		7,330,924	
Glenrock III **[a]**	98,797,623	**11/24/2019**	81,014,051	0.030	2,430,422		2,430,422	
Goodnoe	274,691,486	**12/20/2019**	274,691,486	0.030	8,240,745		8,240,745	
High Plains	287,973,637	**12/19/2019**	287,973,637	0.030	8,639,209		8,639,209	
Leaning Juniper	288,409,597	**9/13/2019**	288,409,597	0.030	8,652,288		8,652,288	
Marengo	466,633,801	**1/27/2020**	466,633,801	0.030	13,999,014		13,999,014	
Marengo II	224,277,607	**2/25/2020**	224,277,607	0.030	6,728,328		6,728,328	
McFadden Ridge	88,286,029	**11/17/2019**	88,286,029	0.030	2,648,581		2,648,581	
Rolling Hills **[c]**	-	**10/17/2019**	-	0.030	-		-	
Seven Mile	361,745,049	**9/9/2019**	361,745,049	0.030	10,852,351		10,852,351	
Seven Mile II	77,267,397	**9/9/2019**	77,267,397	0.030	2,318,022		2,318,022	
Dunlap I	403,257,162	**9/7/2020**	403,257,162	0.030	12,097,715		12,097,715	
Foote Creek I	154,521,376	**3/24/2021**	154,521,376	0.030	4,635,641		4,635,641	
Pryor Mountain **[b]**	812,831,508	**VARIOUS**	812,831,508	0.030	24,384,945		24,384,945	
Cedar Springs II	602,307,625	**12/4/2020**	602,307,625	0.030	18,069,229		18,069,229	
Ekola Flats **[b]**	709,883,219	**VARIOUS**	709,883,219	0.030	21,296,497		21,296,497	
TB Flats **[b]**	1,407,343,904	**VARIOUS**	1,407,343,904	0.030	42,220,317		42,220,317	
Foote Creek II	7,068,355	**11/21/2023**	7,068,355	0.030	212,051	110%	233,256	
Foote Creek III	97,310,244	**11/21/2023**	97,310,244	0.030	2,919,307	110%	3,211,238	
Foote Creek IV	65,996,549	**11/21/2023**	65,996,549	0.030	1,979,896	110%	2,177,886	
Rock Creek I	619,264,203	12/31/2024	619,264,203	0.030	18,577,926	110%	20,435,719	
Rock Creek II	470,583,953	9/30/2025	470,583,953	0.030	14,117,519	110%	15,529,271	
Rock River I	193,878,595	12/1/2024	193,878,595	0.030	5,816,358	110%	6,397,994	
Total KWh Production	7,977,942,118		7,938,909,490		238,167,285		242,529,591	
Total Federal Production Tax Credit							242,529,591	**Ref. 7.3**
						June 2023 Results of Operations PTC	196,377,610	**Ref. 7.3**
						Pro forma Adjustment	46,151,981	

Repowering In Service dates in **bold** reflect actual in-service dates.

[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 and Glenrock III, approximately 8.3% and 17%, respectively of the total generation is not PTC eligible.

[b] Pryor Mountain, Ekola Flats, and TB Flats were placed in service using circuits which results in multiple placed in service date

[c] Oregon does not include Rolling Hills in rate base, therefore, there are no credits for Rolling Hills

PacifiCorp
Oregon General Rate Case - December 2025
PowerTax ADIT Balance

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Tax:							
ADIT - California	282	3	(24,068,668)	CA	Situs	-	7.4.1
ADIT - Idaho	282	3	(31,341,583)	ID	Situs	-	7.4.1
ADIT - Oregon	282	3	(80,807,614)	OR	Situs	(80,807,614)	7.4.1
ADIT - Other	282	3	810,675	OTHER	0.000%	-	7.4.1
ADIT - Utah	282	3	(309,633,021)	UT	Situs	-	7.4.1
ADIT - Washington	282	3	(26,302,832)	WA	Situs	-	7.4.1
ADIT - Wyoming	282	3	(67,728,251)	WYP	Situs	-	7.4.1
ADIT - SG	282	3	(2,542,415,218)	SG	26.884%	(683,506,900)	7.4.1
ADIT - SO	282	3	(171,405,033)	SO	27.425%	(47,008,629)	7.4.1
ADIT - DITBAL	282	1	3,020,474,021	DITBAL	24.951%	753,624,533	7.4.1
ADIT - Accelerated Pollution Control Facilitie	281	1	128,320,334	SG	26.884%	34,497,840	7.4.1
			(104,097,190)			(23,200,770)	7.4.1
ADIT - Other Property Flowthrough	282	3	(1,569,879)	OR	Situs	(1,569,879)	7.4.1
Schedule M Adjustment - Permanent	SCHMAP	3	(22,041)	SCHMDEXP	26.812%	(5,910)	7.4.1
Schedule M Adjustment	SCHMAT	3	12,781,744	CIAC	24.998%	3,195,232	7.4.1
Schedule M Adjustment	SCHMAT	3	4,758,555	SCHMDEXP	26.812%	1,275,884	7.4.1
Schedule M Adjustment	SCHMAT	3	(1,602,441)	SO	27.425%	(439,477)	7.4.1
Schedule M Adjustment	SCHMAT	3	126,219,170	SNP	26.136%	32,988,485	7.4.1
Schedule M Adjustment	SCHMAT	3	(2,642,844)	SNPD	24.998%	(660,669)	7.4.1
Schedule M Adjustment	SCHMDT	3	(83,720,885)	GPS	27.425%	(22,960,843)	7.4.1
Schedule M Adjustment	SCHMDT	3	(12,971,804)	SG	26.884%	(3,487,360)	7.4.1
Schedule M Adjustment	SCHMDT	3	(10,828,269)	SO	27.425%	(2,969,703)	7.4.1
Schedule M Adjustment	SCHMDT	3	139,973,599	TAXDEPR	26.295%	36,806,068	7.4.1
Schedule M Adjustment	SCHMDT	3	213,953,199	SNP	26.136%	55,918,541	7.4.1
Deferred Income Tax Expense	41110	3	(3,142,596)	CIAC	24.998%	(785,599)	7.4.1
Deferred Income Tax Expense	41110	3	(1,169,967)	SCHMDEXP	26.812%	(313,696)	7.4.1
Deferred Income Tax Expense	41110	3	393,986	SO	27.425%	108,052	7.4.1
Deferred Income Tax Expense	41110	3	(31,033,003)	SNP	26.136%	(8,110,747)	7.4.1
Deferred Income Tax Expense	41110	3	649,785	SNPD	24.998%	162,436	7.4.1
Deferred Income Tax Expense	41010	3	(20,584,119)	GPS	27.425%	(5,645,291)	7.4.1
Deferred Income Tax Expense	41010	3	(3,189,326)	SG	26.884%	(857,423)	7.4.1
Deferred Income Tax Expense	41010	3	(2,662,303)	SO	27.425%	(730,149)	7.4.1
Deferred Income Tax Expense	41010	3	34,414,749	TAXDEPR	26.295%	9,049,361	7.4.1
Deferred Income Tax Expense	41010	3	52,603,817	SNP	26.136%	13,748,468	7.4.1
Deferred Income Tax Exp. - Flowthrough	41110	3	2,051,055	OR	Situs	2,051,055	7.4.1
Deferred Income Tax Exp. - Flowthrough	41110	3	(36,543,359)	SG	26.884%	(9,824,374)	7.4.1
Deferred Income Tax Exp. - Flowthrough	41110	3	(3,457,437)	SO	27.425%	(948,218)	7.4.1
Deferred Inc. Tax Exp. - Other Flowthrough	41110	3	630,098	OR	Situs	630,098	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, 2024. Updates the property related schedule m-items and associated deferred income tax expense for the 12 months ended December 31, 2024.

PacifiCorp
Oregon General Rate Case - December 2025
PowerTax Adjustment for Year Ended December 2024

Book Tax Difference		Total Company			STATE Allocation
Description - ADIT	**#**	**Base Period***	**Adjustment**	**Adjusted Utility**	**2020 Protocol**
Accumulated Deferred Income Taxes (CA)	**	0	(24,068,668)	(24,068,668)	CA
Accumulated Deferred Income Taxes (IDU)	**	0	(31,341,583)	(31,341,583)	IDU
Accumulated Deferred Income Taxes (OR)	**	0	(80,807,614)	(80,807,614)	OR
Accumulated Deferred Income Taxes (OTHER)	**	0	810,675	810,675	OTHER
Accumulated Deferred Income Taxes (UT)	**	0	(309,633,021)	(309,633,021)	UT
Accumulated Deferred Income Taxes (WA)	**	0	(26,302,832)	(26,302,832)	WA
Accumulated Deferred Income Taxes (WY)	**	0	(67,728,251)	(67,728,251)	WYP
Accumulated Deferred Income Taxes (SG)	**	0	(2,542,415,218)	(2,542,415,218)	SG
Accumulated Deferred Income Taxes (SO)	**	0	(171,405,033)	(171,405,033)	SO
Accumulated Deferred Income Taxes (DITBAL)	**	(3,020,474,021)	3,020,474,021	0	DITBAL
Accelerated Pollution Control Facilities ADIT (SG) - FERC 281	**	(128,320,334)	128,320,334	0	SG
Total		(3,148,794,355)	**(104,097,190)**	(3,252,891,545)	
			Ref. 7.4	-	
ADIT - Other Property Flowthrough - OR	105.272	13,614,613	**(1,569,879)**	12,044,734	OR
			Ref. 7.4		

Book Tax Difference		Total Company			STATE Allocation	
Description - Schedule M Items	**#**	**Base Period***	**Adjusted Utility**	**Adjustment**	**2020 Protocol**	
		Per Tax Model	**Per PowerTax**			
Schedule M Additions - Permanent:						
Book Depreciation Allocated to Capitalized M&E	105.127	153,260	131,219	**(22,041)**	SCHMDEXP	**Ref 7.4**
Schedule M Additions - Temporary:						
Book Depreciation	105.120	1,086,392,617	1,091,151,172	**4,758,555**	SCHMDEXP	**Ref 7.4**
Capitalized Labor & Benefits Costs	105.100	4,556,420	2,953,979	**(1,602,441)**	SO	**Ref 7.4**
CIAC	105.130	137,504,173	150,285,917	**12,781,744**	CIAC	**Ref 7.4**
Avoided Costs	105.142	90,682,293	216,901,463	**126,219,170**	SNP	**Ref 7.4**
Reimbursements	105.140	2,642,844	-	**(2,642,844)**	SNPD	**Ref 7.4**
Capitalization of Test Energy	105.146	-	-	**-**	SG	
Total Schedule M Additions		1,321,778,347	1,461,292,532	139,514,185		
Schedule M Deductions - Temporary:						
Repair Deduction	105.122	173,184,648	160,212,844	**(12,971,804)**	SG	**Ref 7.4**
Tax Depreciation	105.125	1,264,819,225	1,404,792,824	**139,973,599**	TAXDEPR	**Ref 7.4**
Book Capitalized Depreciation	105.137	10,828,269	-	**(10,828,269)**	SO	**Ref 7.4**
AFUDC - Debt	105.141	47,393,721	113,640,559	**66,246,838**	SNP	**Ref 7.4**
AFUDC - Equity	105.141	103,254,631	250,960,992	**147,706,361**	SNP	**Ref 7.4**
Removal Costs	105.175	75,935,704	42,596,155	**(33,339,549)**	GPS	**Ref 7.4**
Tax Gain / (Loss) on Prop. Disposition	105.152	53,986,355	3,605,019	**(50,381,336)**	GPS	**Ref 7.4**
Book Gain/Loss on Prop. Disposition	105.470	-	-	**-**	GPS	**Ref 7.4**
Total Schedule M Deductions		1,729,402,553	1,975,808,393	246,405,840		

Book Tax Difference		Total Company			STATE Allocation	
Description - Deferred Income Tax Expense	**#**	**Base Period***	**Adjusted Utility**	**Adjustment**	**2020 Protocol**	
		Per Tax Model	**Per PowerTax**			
Flow-through:						
California	105.115	(506,362)	(1,360,520)	(854,158)	CA	
Idaho	105.115	(357,584)	(268,534)	89,050	IDU	
Oregon	105.115	(2,099,714)	(48,659)	2,051,055	OR	**Ref 7.4**
Washington	105.115	(27,143)	(263,220)	(236,077)	WA	
Wyoming - P	105.115	(1,344,931)	(197,626)	1,147,305	WYP	
Wyoming - U	105.115	(741,889)	0	741,889	WYU	
OTHER	105.115	(18,568)	0	18,568	NREG	
Utah	105.115	(397,696)	(2,796,589)	(2,398,893)	UT	
FERC	105.115	(177,191)	0	177,191	FERC	
SG	105.115	(7,590,654)	(44,134,013)	(36,543,359)	SG	**Ref 7.4**
SO	105.115	(650,821)	(4,108,258)	(3,457,437)	SO	**Ref 7.4**
Total		(13,912,553)	(53,177,418)	(39,264,865)		
Other Property Flowthrough - Oregon - Tax	105.272	(13,852)	(53,286)	(39,434)		
Other Property Flowthrough - Oregon - Book	105.272	272,341	941,873	669,532		
Total		258,490	888,587	**630,098**	OR	**Ref 7.4**

PacifiCorp
Oregon General Rate Case - December 2025
Pro Forma Tax Balances

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Tax:							
Schedule M Adjustment Permanent	SCHMAP	3	12,329	SE	26.339%	3,247	
	SCHMAP	3	(740,085)	SO	27.425%	(202,972)	
	SCHMDP	3	(2,958,203)	SE	26.339%	(779,165)	
	SCHMDP	3	(6,046)	SNP	26.136%	(1,580)	
Schedule M Adjustment Temporary	SCHMAT	3	(5,481,922)	BADDEBT	38.939%	(2,134,584)	
	SCHMAT	3	4,882,557	CA	Situs	-	
	SCHMAT	3	1,595,245	GPS	27.425%	437,503	
	SCHMAT	3	(362,035)	ID	Situs	-	
	SCHMAT	3	3,667,348	OR	Situs	3,667,348	
	SCHMAT	3	206,187,854	OTHER	0.000%	-	
	SCHMAT	3	(2,985,106)	SE	26.339%	(786,251)	
	SCHMAT	3	1,552,200	SG	26.884%	417,296	
	SCHMAT	3	(404,087)	SNP	26.136%	(105,612)	
	SCHMAT	3	10,497,378	SO	27.425%	2,878,955	
	SCHMAT	3	371,643	TROJD	26.787%	99,551	
	SCHMAT	3	(2,694,434)	UT	Situs	-	
	SCHMAT	3	9,787,241	WA	Situs	-	
	SCHMAT	3	(802,998)	WYP	Situs	-	
						-	
	SCHMDT	3	201,774	CA	Situs	-	
	SCHMDT	3	2,756,080	ID	Situs	-	
	SCHMDT	3	(152,081)	OR	Situs	(152,081)	
	SCHMDT	3	(623,557,695)	OTHER	0.000%	-	
	SCHMDT	3	(26,150,433)	SE	26.339%	(6,887,794)	
	SCHMDT	3	2,648,340	SG	26.884%	711,984	
	SCHMDT	3	(44,060)	SNPD	24.998%	(11,014)	
	SCHMDT	3	317,920,096	SO	27.425%	87,191,067	
	SCHMDT	3	10,517,246	UT	Situs	-	
	SCHMDT	3	116,162	WA	Situs	-	
	SCHMDT	3	5,665,239	WYP	Situs	-	
Current Federal Tax Credits	40910	3	(12,299)	SE	26.339%	(3,239)	
	40910	3	5,366	SO	27.425%	1,472	

Description of Adjustment:

This adjustment normalizes the Base period Schedule M to an estimated proforma level of expense for the CY December 2025 Test period.

PacifiCorp
Oregon General Rate Case - December 2025
(cont.) Pro Forma Tax Balances

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Tax:							
Deferred Tax Expense Debit	41010	3	49,609	CA	Situs	-	
	41010	3	677,627	ID	Situs	-	
	41010	3	(37,391)	OR	Situs	(37,391)	
	41010	3	(153,311,638)	OTHER	0.000%	-	
	41010	3	(6,429,503)	SE	26.339%	(1,693,474)	
	41010	3	651,137	SG	26.884%	175,053	
	41010	3	(10,833)	SNPD	24.998%	(2,708)	
	41010	3	78,165,742	SO	27.425%	21,437,319	
	41010	3	2,585,833	UT	Situs	-	
	41010	3	28,560	WA	Situs	-	
	41010	3	1,392,889	WYP	Situs	-	
Deferred Tax Expense Credit	41110	3	1,347,818	BADDEBT	38.939%	524,822	
	41110	3	(1,200,455)	CA	Situs	-	
	41110	3	89,012	ID	Situs	-	
	41110	3	-	FERC	0.000%	-	
	41110	3	(392,216)	GPS	27.425%	(107,567)	
	41110	3	(901,675)	OR	Situs	(901,675)	
	41110	3	(50,694,580)	OTHER	0.000%	-	
	41110	3	733,935	SE	26.339%	193,312	
	41110	3	(382,691)	SG	26.884%	(102,883)	
	41110	3	99,351	SNP	26.136%	25,966	
	41110	3	(2,580,948)	SO	27.425%	(707,837)	
	41110	3	(91,374)	TROJD	26.787%	(24,476)	
	41110	3	662,469	UT	Situs	-	
	41110	3	(2,406,350)	WA	Situs	-	
	41110	3	197,430	WYP	Situs	-	
	41110	3	-	WYU	Situs	-	
ITC Amortization	41140	3	438,995	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 2025 Test period.

PacifiCorp
Oregon General Rate Case - December 2025
(cont.) Pro Forma Tax Balances

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Tax:							
ADIT Balance 190	190	3	169,471	BADDEBT	38.939%	65,990	
	190	3	88,652	CA	Situs	-	
	190	3	(146,484)	ID	Situs	-	
	190	3	-	OR	Situs	-	
	190	3	10,195,801	OTHER	0.000%	-	
	190	3	40,387	SE	26.339%	10,638	
	190	3	(295,932)	SG	26.884%	(79,559)	
	190	3	(16,407,742)	SO	27.425%	(4,499,900)	
	190	3	(25,449)	TROJD	26.787%	(6,817)	
	190	3	(1,081,653)	UT	Situs	-	
	190	3	(2,559,319)	WA	Situs	-	
	190	3	(58,317)	WYP	Situs	-	
	190	3	1,759,092	SNPD	24.998%	439,745	
ADIT Balance 282	282	3	28,978	OTHER	0.000%	-	
	282	3	(28,100)	SE	26.339%	(7,401)	
	282	3	(1,449)	SO	27.425%	(397)	
	282	3	349,408	UT	Situs	-	
	282	3	116,150	WYP	Situs	-	
	282	3	56,858	ID	Situs	-	
ADIT Balance 283	283	3	722,970	CA	Situs	-	
	283	3	6,321	GPS	27.425%	1,734	
	283	3	1,726,525	ID	Situs	-	
	283	3	-	OR	Situs	-	
	283	3	(15,183,172)	OTHER	0.000%	-	
	283	3	-	SE	26.339%	-	
	283	3	385,946	SG	26.884%	103,758	
	283	3	8,310	SNP	26.136%	2,172	
	283	3	5,633,319	SO	27.425%	1,544,964	
	283	3	120,366	UT	Situs	-	
	283	3	(38,196)	WA	Situs	-	
	283	3	2,168,629	WYP	Situs	-	
	283	3	6,525	WYU	Situs	-	
ADIT Balance 255	255	3	162,988	UT	Situs	-	
	255	3	17,543	SG	26.884%	4,716	
	255	3	5,822	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 2025 Test period.

PacifiCorp
Oregon General Rate Case - December 2025
Wyoming Wind Generation Tax

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Taxes Other Than Income	408	3	1,907,065	SG	26.884%	512,698	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 person producing the electricity. The tax is one dollar on each megawatt hour of electricity produced from wind resources at the point of interconnection with an electric transmission line.

PacifiCorp
Oregon General Rate Case - December 2025
Wyoming Wind Generation Tax

Wind Plant	2025 NPC MWH Production (b)	Tax Begins	2025 $1/MWH Tax	
Foote Creek	154,521	3/24/2024	154,521	
Glenrock I	81,014	1/1/2012	81,014	
Glenrock III	274,691	1/1/2012	274,691	
Seven Mile Hill	361,745	1/1/2012	361,745	
Seven Mile Hill II	77,267	1/1/2012	77,267	
Rolling Hills	-	1/17/2012	-	
High Plains	287,974	9/1/2012	287,974	
McFadden Ridge	88,286	9/1/2012	88,286	
Dunlap	403,257	10/1/2013	403,257	
Cedar Springs Wind II	602,308	12/8/2023	602,308	
Ekola Flats Wind	709,883	VARIOUS	709,883	
TB Flats Wind	812,832	VARIOUS	812,832	
Foote Creek II-IV (a)	-	11/21/2026	-	
Rock Creek I (a)	-	12/31/2027	-	
Rock Creek II (a)	-	9/30/2028	-	
Rock River I (a)	-	12/1/2027	-	
Total Wyoming Wind MWH	3,853,779		3,853,778	
June 2023 Results of Operations PTC			1,946,713	
Adjustment to normalize to CY December 2025			**1,907,065**	**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.

PacifiCorp
Oregon General Rate Case - December 2025
TCJA EDIT Adjustment

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Other Reg. Liabilities	254	1	1,785	OR	Situs	1,785	7.7.1
Other Reg. Liabilities - Protected EDIT	254	3	29,708,556	OR	Situs	29,708,556	7.7.1
Adjustment to Tax:							
Accum. Def. Inc. Tax. Bal.	190	1	(439)	OR	Situs	(439)	7.7.1
Accum. Def. Inc. Tax. Bal.-Protected EDIT	190	3	(7,304,324)	OR	Situs	(7,304,324)	7.7.1
Accum Def Inc Tax Bal -Protect EDIT PMI	282	3	397,796	SE	26.339%	104,776	7.7.1
EDIT Amortization	41110	3	849,173	OR	Situs	849,173	7.7.1

Description of Adjustment:

Protected PP&E EDIT: This adjustment reflects the level of protected property EDIT amortization and adjusts the rate base for the test period.

PacifiCorp
Oregon General Rate Case - December 2025
TCJA EDIT Adjustment

Description	Account	June 2023 End of Period	December 2024 End of Period	Adjustment	Ref
EDIT Reg Liabilities	254OR	(1,785)	-	**1,785**	**Page 7.7**
Protected EDIT Reg Liabilities	254OR	(342,777,555)	(313,069,000)	**29,708,556**	**Page 7.7**
Grand Total		**(342,779,340)**	**(313,069,000)**	**29,710,341**	
DTA - EDIT Balances	190OR	439	-	**(439)**	**Page 7.7**
DTA - Protected EDIT Balances	190OR	84,277,346	76,973,023	**(7,304,324)**	**Page 7.7**
DTL - Protected EDIT Balances - PMI	282SE	(1,650,109)	(1,252,313)	**397,796**	**Page 7.7**
Grand Total		**84,277,785**	**76,973,023**	**(7,304,763)**	

Oregon				
EDIT Amortization	**June 2023**	**December 2024**	**Adjustment**	
Protected EDIT - RSGM	(13,796,329)	(12,889,812)	906,517	
Protected EDIT - PMI	7,400	(49,944)	(57,344)	
Total Protected EDIT Amortization	(13,788,929)	(12,939,756)	849,173	**Page 7.7**

NOTE: The Protected EDIT Amortization is adjusted to the proforma December 2024 level of amortization, as this balance relates to property.

PacifiCorp
Oregon General Rate Case - December 2025
Oregon Corporate Activity Tax & Metro BIT

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
OCAT - Remove Base Period	40911	1	(2,878,000)	OR	Situs	(2,878,000)	7.8.1
OCAT - Test Period	408	3	6,155,000	OR	Situs	6,155,000	7.8.1
Metro Business Income Tax - Base Period	40911	1	(106,000)	OR	Situs	(106,000)	7.8.2
Metro Business Income Tax - Test Period	40911	3	219,094	OR	Situs	219,094	7.8.2

Description of Adjustment:

This adjustment is to adjust the Oregon Corporate Activity Tax and Metro Business Income Tax/Metro Supportive Housing Services tax amount for the test period. Although included in Account 40911 in the base period, the Oregon Corporate Activity Tax will be included in Account 408 for purposes of the general rate case.

PacifiCorp
Oregon General Rate Case - December 2025
Oregon Corporate Activity Tax & Metro BIT

			OR CAT	
Jun-23	12 months	Oregon Corporate Activity Tax - Base Period - Account 409	2,878,000	
		Adjustment to Account 40911	2,878,000	**Ref. 7.8**
Dec-23	12 months	Oregon Corporate Activity Tax - 2025 Forecast - Account 408	6,155,000	
		Adjustment to Account 408	6,155,000	**Ref. 7.8**

Note: The OCAT included in the base period is charged to Account 40911. As per Docket UE-399, the OCAT will be included in rates in Account 408. The OCAT was deferred through December 31, 2022, therefore, only 6 months of the OCAT is included in the base period data.

PacifiCorp
Oregon General Rate Case - December 2025
Oregon Corporate Activity Tax & Metro BIT

			Metro Supportive Housing Services Tax	
Jun-23	12 months	Metro Supportive Housing Services Tax - Base Period	106,000	
Dec-25	12 months	Metro Supportive Housing Services Tax - 2025 Forecast	219,094	
		Total	219,094	
Adjustment to Account 40911			113,094	**Ref. 7.8**

Note: The Metro Supporting Housing Services tax was deferred through December 31, 2022, therefore, only 6 months of the tax is included in the base period data.

PacifiCorp
Oregon General Rate Case - December 2025
AFUDC - Equity

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
AFUDC - Equity	419	1	(147,436,288)	SNP	26.136%	(38,533,764)	7.9.1

Description of Adjustment:

This adjustment brings in the appropriate level of AFUDC - Equity into results to align the tax Schedule M with regulatory income.

PacifiCorp Page 7.9.1
Oregon General Rate Case - December 2025
AFUDC - Equity

			Equity SAP Accts 382000 & 382060	
Jun-23	12 months	Account 419	(103,524,703)	
Dec-24	12 months	AFUDC-Equity SCHMDT	(250,960,992)	
Dec-24	12 months	AFUDC-Intangible Basis - Equity	-	
		Total	(250,960,992)	
Adjustment to Account 419			**(147,436,288)**	**Ref. 7.9**

Tab 6 - P_rc @_qc

PacifiCorp
Oregon General Rate Case – December 2025
Rate Base Adjustment Index

The Company used year-end rate base as of June 2023 as the starting point for establishing the adjustments made to the test period. Test period electric plant in service is reflected using December 2024 ending balances. Other rate base components are reflected using a December 2025 13 month average balance. The following rate base adjustments are included.

PacifiCorp
Oregon General Rate Case - December 2025
Tab 8 Adjustment Summary

			8.2	8.3	8.4	8.5	8.6	8.7
		Total Adjustments	Trapper Mine Rate Base	Jim Bridger Mine Rate Base	Pro Forma Plant Additions and Retirements	Customer Advances for Construction	Regulatory Assets & Liabilities Amortization	Plant Held for Future Use
1	Operating ReWenues:							
2	General Business ReWenues	-	-	-	-	-	-	-
3	Interdepartmental	-	-	-	-	-	-	-
4	Special Sales	-	-	-	-	-	-	-
5	Other Operating ReWenues	(4,075,388)	-	-	-	-	(4,075,388)	-
6	Total Operating ReWenues	(4,075,388)	-	-	-	-	(4,075,388)	-
7								
8	Operating Expenses:							
9	Steam Production	(372,219)	-	-	-	-	-	-
10	Nuclear Production	-	-	-	-	-	-	-
11	Hydro Production	(563,449)	-	-	-	-	-	-
12	Other Power Supply	899,010	-	-	-	-	-	-
13	Transmission	-	-	-	-	-	-	-
14	Distribution	855,753	-	-	-	-	855,753	-
15	Customer Accounting	-	-	-	-	-	-	-
16	Customer SerWice & Info	-	-	-	-	-	-	-
17	Sales	-	-	-	-	-	-	-
18	AdministratiWe & General	349,677	-	-	-	-	-	-
19								
20	Total O&M Expenses	1,168,773	-	-	-	-	855,753	-
21								
22	Depreciation	5,713,429	-	-	-	-	-	-
23	Amortization	17,636,230	-	-	-	-	-	-
24	Taxes Other Than Income	-	-	-	-	-	-	-
25	Income Taxes - Federal	(3,690,866)	(109,796)	(49,345)	(2,738,985)	(141,812)	(816,849)	38,725
26	Income Taxes - State	(835,879)	(24,866)	(11,175)	(620,304)	(32,117)	(184,994)	8,770
27	Income Taxes - Def Net	(10,338,733)	124,280	-	(4,312,521)	-	(210,401)	-
28	InWestment Tax Credit Adj.	-	-	-	-	-	-	-
29	Misc ReWenue & Expense	-	-	-	-	-	-	-
30								
31	Total Operating Expenses:	9,652,955	(10,381)	(60,520)	(7,671,810)	(173,929)	(356,490)	47,495
32								
33	Operating ReW For Return:	(13,728,343)	10,381	60,520	7,671,810	173,929	(3,718,898)	(47,495)
34								
35	Rate Base:							
36	Electric Plant In SerWice	1,280,364,158	1,685,813	9,499,747	1,200,747,833	-	-	-
37	Plant Held for Future Use	(7,461,409)	-	-	-	-	-	(7,461,409)
38	Misc Deferred Debits	(80,576,798)	-	-	-	-	-	-
39	Elec Plant Acq Adj	(20,258)	-	-	-	-	(20,258)	-
40	Nuclear Fuel	(28,783,408)	-	-	-	-	-	-
41	Prepayments	-	-	-	-	-	-	-
42	Fuel Stock	1,024,593	-	-	-	-	-	-
43	Material & Supplies	-	-	-	-	-	-	-
44	Working Capital	(184,593)	(88,159)	(1,811)	(100,503)	(5,204)	(4,371)	1,421
45	Weatherization Loans	-	-	-	-	-	-	-
46	Misc Rate Base	-	-	-	-	-	-	-
47								
48	Total Electric Plant:	1,164,362,284	1,597,654	9,497,936	1,200,647,331	(5,204)	(24,628)	(7,459,988)
49								
50	Rate Base Deductions:							
51	Accum ProW For Deprec	(1,906,517)	-	-	-	-	-	-
52	Accum ProW For Amort	276,415	-	-	-	-	-	-
53	Accum Def Income Tax	41,418,474	32,901	7,893	4,351,639	-	-	-
54	Unamortized ITC	-	-	-	-	-	-	-
55	Customer AdW For Const	27,323,942	-	-	-	27,323,942	-	-
56	Customer SerWice Deposits	-	-	-	-	-	-	-
57	Misc Rate Base Deductions	(807,875)	-	-	-	-	-	-
58								
59	Total Rate Base Deductions	66,304,439	32,901	7,893	4,351,639	27,323,942	-	-
60								
61	Total Rate Base:	1,230,666,723	1,630,555	9,505,829	1,204,998,969	27,318,739	(24,628)	(7,459,988)
62								
63	Return on Rate Base	-2.099%	-0.003%	-0.017%	-1.657%	-0.029%	-0.070%	0.008%
64								
65	Return on Equity	-4.197%	-0.006%	-0.034%	-3.313%	-0.058%	-0.140%	0.015%
66								
67	TAX CALCULATION:							
68	Operating ReWenue	(28,593,820)	-	-	-	-	(4,931,142)	-
69	Other Deductions	-	-	-	-	-	-	-
70	Interest (AFUDC)	-	-	-	-	-	-	-
71	Interest	31,867,893	42,223	246,152	31,203,231	707,414	(638)	(193,175)
72	Schedule "M" Additions	33,466,404	(505,481)	-	16,571,619	-	855,753	-
73	Schedule "M" Deductions	(8,583,880)	-	-	(968,522)	-	-	-
74	Income Before Tax	(18,411,430)	(547,704)	(246,152)	(13,663,090)	(707,414)	(4,074,751)	193,175
75								
76	State Income Taxes	(835,879)	(24,866)	(11,175)	(620,304)	(32,117)	(184,994)	8,770
77	Taxable Income	(17,575,551)	(522,838)	(234,976)	(13,042,786)	(675,297)	(3,889,757)	184,405
78								
79	Federal Income Taxes + Other	(3,690,866)	(109,796)	(49,345)	(2,738,985)	(141,812)	(816,849)	38,725
	APPROXIMATE PRICE CHANGE	149,674,120	159,071	927,356	117,555,514	2,665,121	5,104,769	(727,771)

PacifiCorp
Oregon General Rate Case - December 2025
Tab 8 Adjustment Summary

		8.8	8.9	8.10	8.11	8.12	8.13	8.14
		Pension and Other Post-retirement Plan Balances Removal	Remove Rolling Hills	Deer Creek Mine Adjustment	Emissions Control Investment Adjustment	Transmission Project Adjustment	Cholla Unit 4 Retirement	Miscellaneous Rate Base
1	Operating ReWenues:							
2	General Business ReWenues	-	-	-	-	-	-	-
3	Interdepartmental	-	-	-	-	-	-	-
4	Special Sales	-	-	-	-	-	-	-
5	Other Operating ReWenues	-	-	-	-	-	-	-
6	Total Operating ReWenues	-	-	-	-	-	-	-
7								
8	Operating Expenses:							
9	Steam Production	-	-	(372,219)	-	-	-	-
10	Nuclear Production	-	-	-	-	-	-	-
11	Hydro Production	-	-	-	-	-	-	-
12	Other Power Supply	-	(311,183)	-	-	-	-	-
13	Transmission	-	-	-	-	-	-	-
14	Distribution	-	-	-	-	-	-	-
15	Customer Accounting	-	-	-	-	-	-	-
16	Customer SerWice & Info	-	-	-	-	-	-	-
17	Sales	-	-	-	-	-	-	-
18	AdministratiWe & General	-	(76,991)	797,657	(1,103,132)	-	732,144	-
19								
20	Total O&M Expenses	-	(388,174)	425,438	(1,103,132)	-	732,144	-
21								
22	Depreciation	-	-	-	(138,078)	-	-	-
23	Amortization	-	-	-	-	-	28,222	-
24	Taxes Other Than Income	-	-	-	-	-	-	-
25	Income Taxes - Federal	354,636	680,869	422,491	232,833	687	(141,225)	(19,710)
26	Income Taxes - State	80,315	154,198	95,682	52,730	156	(31,983)	(4,464)
27	Income Taxes - Def Net	-	(482,459)	(518,633)	25,435	-	(9,931)	-
28	InWestment Tax Credit Adj.	-	-	-	-	-	-	-
29	Misc ReWenue & Expense	-	-	-	-	-	-	-
30								
31	Total Operating Expenses:	434,952	(35,567)	424,979	(930,213)	843	577,227	(24,174)
32								
33	Operating ReW For Return:	(434,952)	35,567	(424,979)	930,213	(843)	(577,227)	24,174
34								
35	Rate Base:							
36	Electric Plant In SerWice	-	(52,478,373)	-	(979,001)	(182,000)	-	-
37	Plant Held for Future Use	-	-	-	-	-	-	-
38	Misc Deferred Debits	(61,547,849)	-	(17,450,145)	-	-	(603,848)	2,773,151
39	Elec Plant Acq Adj	-	-	-	-	-	-	-
40	Nuclear Fuel	(28,783,408)	-	-	-	-	-	-
41	Prepayments	-	-	-	-	-	-	-
42	Fuel Stock	-	-	-	-	-	-	1,024,593
43	Material & Supplies	-	-	-	-	-	-	-
44	Working Capital	13,013	13,370	28,231	(24,460)	25	16,722	(723)
45	Weatherization Loans	-	-	-	-	-	-	-
46	Misc Rate Base	-	-	-	-	-	-	-
47								
48	Total Electric Plant:	(90,318,244)	(52,465,003)	(17,421,914)	(1,003,461)	(181,975)	(587,126)	3,797,020
49								
50	Rate Base Deductions:							
51	Accum ProW For Deprec	-	(419,923)	-	-	36,100	-	-
52	Accum ProW For Amort	-	-	-	-	-	-	-
53	Accum Def Income Tax	22,001,105	12,491,957	1,064,639	88,356	13,525	(11,147)	-
54	Unamortized ITC	-	-	-	-	-	-	-
55	Customer AdW For Const	-	-	-	-	-	-	-
56	Customer SerWice Deposits	-	-	-	-	-	-	-
57	Misc Rate Base Deductions	-	-	-	-	-	-	-
58								
59	Total Rate Base Deductions	22,001,105	12,072,034	1,064,639	88,356	49,625	(11,147)	-
60								
61	Total Rate Base:	(68,317,139)	(40,392,968)	(16,357,275)	(915,104)	(132,350)	(598,273)	3,797,020
62								
63	Return on Rate Base	0.072%	0.049%	0.012%	0.019%	0.000%	-0.010%	-0.004%
64								
65	Return on Equity	0.144%	0.098%	0.023%	0.038%	0.000%	-0.021%	-0.008%
66								
67	TAX CALCULATION:							
68	Operating ReWenue	-	388,174	(425,438)	1,241,211	-	(760,367)	-
69	Other Deductions	-	-	-	-	-	-	-
70	Interest (AFUDC)	-	-	-	-	-	-	-
71	Interest	(1,769,060)	(1,045,969)	(423,569)	(23,696)	(3,427)	(15,492)	98,323
72	Schedule "M" Additions	-	-	(1,708,971)	(138,078)	-	40,392	-
73	Schedule "M" Deductions	-	(1,962,286)	(3,818,384)	(34,629)	-	-	-
74	Income Before Tax	1,769,060	3,396,429	2,107,544	1,161,458	3,427	(704,482)	(98,323)
75								
76	State Income Taxes	80,315	154,198	95,682	52,730	156	(31,983)	(4,464)
77	Taxable Income	1,688,745	3,242,231	2,011,861	1,108,728	3,272	(672,499)	(93,859)
78								
79	Federal Income Taxes + Other	354,636	680,869	422,491	232,833	687	(141,225)	(19,710)
	APPROXIMATE PRICE CHANGE	(6,664,783)	(4,342,629)	(1,155,133)	(1,374,794)	(12,912)	729,144	370,424

PacifiCorp
Oregon General Rate Case - December 2025
Tab 8 Adjustment Summary

	8.15	8.16	8.17	8.18	8.19	8.20
	Carbon Plant Closure	Removal of Wildfire Mitigation Capital Rate Base	New Wind Generation Capital Additions_CONF	Wildfire Restoration Costs Deferral Amortization	Aeolus Substation Settlement	Klamath Regulatory Asset
1 Operating ReWenues:						
2 General Business ReWenues	-	-	-	-	-	-
3 Interdepartmental	-	-	-	-	-	-
4 Special Sales	-	-	-	-	-	-
5 Other Operating ReWenues	-	-	-	-	-	-
6 Total Operating ReWenues	-	-	-	-	-	-
7						
8 Operating Expenses:						
9 Steam Production	-	-	-	-	-	-
10 Nuclear Production	-	-	-	-	-	-
11 Hydro Production	-	-	-	-	-	(563,449)
12 Other Power Supply	-	-	1,210,193	-	-	-
13 Transmission	-	-	-	-	-	-
14 Distribution	-	-	-	-	-	-
15 Customer Accounting	-	-	-	-	-	-
16 Customer SerWice & Info	-	-	-	-	-	-
17 Sales	-	-	-	-	-	-
18 AdministratiWe & General	-	-	-	-	-	-
19						
20 Total O&M Expenses	-	-	1,210,193	-	-	(563,449)
21						
22 Depreciation	-	-	5,851,507	-	-	-
23 Amortization	(1,615,751)	-	-	18,880,642	-	343,117
24 Taxes Other Than Income	-	-	-	-	-	-
25 Income Taxes - Federal	297,874	310,366	(2,135,944)	34,770	6,313	83,237
26 Income Taxes - State	67,460	70,289	(483,732)	7,874	1,430	18,851
27 Income Taxes - Def Net	44,130	(281,746)	-	(4,675,742)	-	(41,144)
28 InWestment Tax Credit Adj.	-	-	-	-	-	-
29 Misc ReWenue & Expense	-	-	-	-	-	-
30						
31 Total Operating Expenses:	(1,206,287)	98,909	4,442,024	14,247,544	7,743	(159,389)
32						
33 Operating ReW For Return:	1,206,287	(98,909)	(4,442,024)	(14,247,544)	(7,743)	159,389
34						
35 Rate Base:						
36 Electric Plant In SerWice	-	(16,976,982)	139,047,122	-	-	-
37 Plant Held for Future Use	-	-	-	-	-	-
38 Misc Deferred Debits	(477,793)	-	-	(1,878,302)	-	(1,392,013)
39 Elec Plant Acq Adj	-	-	-	-	-	-
40 Nuclear Fuel	-	-	-	-	-	-
41 Prepayments	-	-	-	-	-	-
42 Fuel Stock	-	-	-	-	-	-
43 Material & Supplies	-	-	-	-	-	-
44 Working Capital	10,930	11,388	(42,169)	1,276	232	(13,803)
45 Weatherization Loans	-	-	-	-	-	-
46 Misc Rate Base	-	-	-	-	-	-
47						
48 Total Electric Plant:	(466,863)	(16,965,594)	139,004,953	(1,877,026)	232	(1,405,816)
49						
50 Rate Base Deductions:						
51 Accum ProW For Deprec	-	334,168	(243,813)	-	(1,613,049)	-
52 Accum ProW For Amort	-	276,415	-	-	-	-
53 Accum Def Income Tax	(642,408)	819,360	-	461,811	396,594	342,249
54 Unamortized ITC	-	-	-	-	-	-
55 Customer AdW For Const	-	-	-	-	-	-
56 Customer SerWice Deposits	-	-	-	-	-	-
57 Misc Rate Base Deductions	(807,875)	-	-	-	-	-
58						
59 Total Rate Base Deductions	(1,450,284)	1,429,943	(243,813)	461,811	(1,216,455)	342,249
60						
61 Total Rate Base:	(1,917,146)	(15,535,651)	138,761,140	(1,415,215)	(1,216,224)	(1,063,567)
62						
63 Return on Rate Base	0.026%	0.017%	-0.249%	-0.267%	0.001%	0.004%
64						
65 Return on Equity	0.051%	0.034%	-0.499%	-0.534%	0.002%	0.008%
66						
67 TAX CALCULATION:						
68 Operating ReWenue	1,615,751	-	(7,061,701)	(18,880,642)	-	220,332
69 Other Deductions	-	-	-	-	-	-
70 Interest (AFUDC)	-	-	-	-	-	-
71 Interest	(49,644)	(402,293)	3,593,195	(36,647)	(31,494)	(27,541)
72 Schedule "M" Additions	(179,487)	(486,783)	-	19,017,440	-	-
73 Schedule "M" Deductions	-	(1,632,714)	-	-	-	(167,345)
74 Income Before Tax	1,485,908	1,548,223	(10,654,895)	173,445	31,494	415,218
75						
76 State Income Taxes	67,460	70,289	(483,732)	7,874	1,430	18,851
77 Taxable Income	1,418,448	1,477,934	(10,171,163)	165,570	30,064	396,367
78						
79 Federal Income Taxes + Other	297,874	310,366	(2,135,944)	34,770	6,313	83,237
APPROXIMATE PRICE CHANGE	(1,860,459)	(1,515,606)	20,850,841	19,416,572	(118,651)	(331,956)

PacifiCorp
Oregon General Rate Case - December 2025
Cash Working Capital

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Cash Working Capital	CWC	3	1,285,122	OR	Situs	1,285,122	Below
Adjustment Detail:							
Cash Working Capital June 2023 - Unadjusted			85,383,086			34,740,058	2.28
Cash Working Capital December 2025 - Normalized			83,534,345			36,025,180	2.28
Adjustment:			(1,848,741)			1,285,122	

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 2022 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, 2025

	Total	California	Oregon	Washington	Wyoming	Wy-PPL	Utah	Idaho	Wy-UPL	FERC
Lead/Lag Study as of 12/22										
Revenue Lag Days	41.52	42.52	48.17	41.27	41.98	41.98	44.89	34.38	41.98	35.62
Expense Lag Days	35.72	41.19	37.25	35.20	35.12	35.12	37.32	38.49	35.12	35.10
Net Lag Days	5.80	1.33	10.92	6.07	6.86	6.86	7.57	-4.11	6.86	0.53
O&M Expense	3,665,861,345	80,910,705	1,141,053,083	291,048,604	538,761,699	470,844,159	1,764,970,139	227,162,491	67,917,540	1
Taxes Other than Income	249,331,003	6,557,390	100,572,803	14,673,274	27,567,386	24,185,627	89,033,664	10,926,485	3,381,759	0
Federal Income Tax	(118,097,100)	(5,840,694)	(42,794,680)	(16,759,745)	(56,384,806)	(51,710,170)	(138,243,788)	(13,013,379)	(4,674,636)	2,878,039
State Income Tax	35,344,422	(566,253)	5,307,130	318,169	(5,201,391)	(5,080,070)	(6,652,441)	126,159	(121,321)	651,796
Total	3,832,439,670	81,061,149	1,204,138,336	289,280,301	504,742,887	438,239,546	1,709,107,574	225,201,755	66,503,342	3,529,837
Divided by Days in Year	365	365	365	365	365	365	365	365	365	365
Avg. Daily Cost of Service	10,499,835	222,085	3,299,009	792,549	1,382,857	1,200,656	4,682,487	616,991	182,201	9,671
Net Lag Days	5.80	1.33	10.92	6.07	6.86	6.86	7.57	(4.11)	6.86	0.53
Cash Working Capital	**83,534,345**	296,286	**36,025,180**	4,810,771	9,486,401	8,236,502	35,446,423	(2,535,833)	1,249,898	5,118
	Ref. 8.1		**Ref. 8.1**							

PacifiCorp
Oregon General Rate Case - December 2025
Trapper Mine Rate Base

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Other Tangible Property	399	1	9,164,849	SE	26.339%	2,413,941	Below
Other Tangible Property	399	3	(2,764,436)	SE	26.339%	(728,128)	Below
			6,400,413			1,685,813	Below
Final Reclamation Liability	2533	3	(319,412)	SE	26.339%	(84,130)	Below
Adjustment to Tax:							
Schedule M Adj - Reclamation Liab	SCHMAT	3	(1,919,125)	SE	26.339%	(505,481)	8.2.2
Deferred Income Tax Expense	41110	3	471,847	SE	26.339%	124,280	8.2.2
Accumulated Def Inc Tax Balance	190	3	124,915	SE	26.339%	32,901	8.2.2
Adjustment Detail							
Other Tangible Property							
June 2023 End of Period Balance			9,164,849				8.2.1
December 2024 End of Period Balance			6,400,413				8.2.1
Adjust to December 2024 End of Period Balance			(2,764,436)				Above
Final Reclamation Liability							
June 2023 12 Mth. Avg. Balance			(10,815,889)				8.2.2
December 2024 12 Mth. Avg. Balance			(11,135,301)				8.2.2
Adjust to December 2024 12 Mth. Avg. Balance			(319,412)				Above

Description of Adjustment:

The Company owns 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. It reflects net plant to recognize the depreciation of the investment over time. This adjustment also walks forward the Reclamation Liability to December 2024 levels. 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 2025
Trapper Mine Rate Base

DESCRIPTION	Jun-23 Actual	Jan-24 Forecast	Feb-24 Forecast	Mar-24 Forecast	Apr-24 Forecast	May-24 Forecast	Jun-24 Forecast	Jul-24 Forecast	Aug-24 Forecast	Sep-24 Forecast	Oct-24 Forecast	Nov-24 Forecast	Dec-24 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	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	2,834,815	2,834,815	2,834,815	2,834,815	2,834,815	2,834,815
Equipment and Facilities	129,061,672	127,680,133	128,111,478	128,053,310	128,096,066	129,279,586	129,397,232	129,398,212	129,093,067	129,230,409	127,610,541	127,649,631	127,649,631
Total Property, Plant, and Equipment	149,645,471	148,263,932	148,695,277	148,637,109	148,679,865	149,863,385	149,981,031	149,982,011	149,676,866	149,814,208	148,194,340	148,233,430	148,233,430
Accumulated Depreciation	(126,467,142)	(130,494,535)	(130,894,214)	(131,293,892)	(131,693,570)	(132,093,249)	(132,492,927)	(132,892,605)	(133,292,284)	(133,691,962)	(134,091,641)	(134,491,319)	(133,722,571)
Total Property, Plant, and Equipment	23,178,329	17,769,397	17,801,064	17,343,217	16,986,295	17,770,137	17,488,104	17,089,405	16,384,582	16,122,246	14,102,699	13,742,111	14,510,859
Other													
Inventories	7,174,482	6,331,271	6,507,651	6,390,531	7,167,305	7,021,275	7,282,099	9,608,104	9,174,003	7,339,622	8,241,420	7,303,759	6,505,472
Prepaid Expenses	247,839	103,906	103,906	103,906	103,906	103,906	103,906	103,906	103,906	103,906	103,906	103,906	103,906
Restricted Funds: Self-bonding for Black Lung	657,793	657,793	657,793	657,793	657,793	657,793	657,793	657,793	657,793	657,793	657,793	657,793	657,793
Advanced Stripping Costs	192,653	186,327	186,327	186,327	186,327	186,327	186,327	186,327	186,327	186,327	186,327	186,327	186,327
Deferred GE Royalty Amount	-	-	-	-	-	-	-	-	-	-	-	-	-
Advance Royalty - State 206-13	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Other	8,272,767	7,279,296	7,455,676	7,338,557	8,115,330	7,969,300	8,230,124	10,556,129	10,122,029	8,287,648	9,189,445	8,251,784	7,453,497
Total Rate Base	31,451,096	25,048,693	25,256,740	24,681,774	25,101,625	25,739,436	25,718,229	27,645,534	26,506,611	24,409,893	23,292,144	21,993,895	21,964,356
PacifiCorp Share	**9,164,849**	**7,299,189**	**7,359,814**	**7,192,269**	**7,314,613**	**7,500,472**	**7,494,292**	**8,055,909**	**7,724,026**	**7,113,043**	**6,787,331**	**6,409,021**	**6,400,413**
	Ref. 8.2												**Ref. 8.2**

PacifiCorp
Oregon General Rate Case - December 2025
Trapper Mine Rate Base
Final Reclamation Liability

Actual

Description:	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23
Final Reclamation Liability	(9,013,125)	(9,111,824)	(11,395,750)	(11,248,760)	(11,087,049)	(11,029,365)	(11,080,983)	(11,085,980)	(11,077,444)	(11,161,488)	(11,232,955)	(11,265,949)

Pro Forma

Description:	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24
Final Reclamation Liability	(10,674,251)	(10,758,078)	(10,841,906)	(10,925,733)	(11,009,560)	(11,093,387)	(11,177,214)	(11,261,042)	(11,344,869)	(11,428,696)	(11,512,523)	(11,596,350)

12 Month Average :		
June 2023 12 Mth. Avg. Balance	(10,815,889)	
December 2024 12 Mth. Avg. Balance	(11,135,301)	
Adjustment to Rate Base	**(319,412)**	**Ref 8.2**

Adjustments for Tax:

Schedule M Add - Pro Forma	**330,402**	
Schedule M Add - Actual	2,249,527	
Adjustment needed	**(1,919,125)**	**Ref 8.2**
Def Inc Tax Exp - Pro Forma	**(81,235)**	
Def Inc Tax Exp - Actual	(553,082)	
Adjustment needed	**471,847**	**Ref 8.2**

ADIT Adjustment for Tax:

Tax Actual Account 287216 (FERC Account 190) M#605.715

Description:	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
Trapper Mine Contract Obligation	2,173,151	2,187,087	2,211,354	2,783,249	2,747,109	2,707,349	2,684,486	2,697,177	2,698,405	2,679,886	2,700,550	2,718,121	2,726,233

Regulation Forecast

Description:	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24
Trapper Mine Contract Obligation	2,603,825	2,624,435	2,645,046	2,665,656	2,686,266	2,706,876	2,727,487	2,748,097	2,768,707	2,789,318	2,809,928	2,830,538	2,851,148

Year End Balance:	
June 2023 End of Period ADIT Balance	2,726,233
December 2024 YE ADIT Balance	2,851,148
Adjustment to Rate Base	**124,915**
	Ref 8.2

PacifiCorp
Oregon General Rate Case - December 2025
Jim Bridger Mine Rate Base

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Other Tangible Property	399	1	39,159,397	SE	26.339%	10,314,240	Below
Other Tangible Property	399	3	(3,092,334)	SE	26.339%	(814,493)	Below
			36,067,063			9,499,747	
Adjustment to Tax:							
Accumulated Def Inc Tax Balance	190	3	29,968	SE	26.339%	7,893	8.3.2
Adjustment Detail							
June 2023 End of Period Balance			39,159,397				8.3.1
December 2024 End of Period Balance			36,067,063				8.3.1
Adjustment to December 2024 End of Period Balance			(3,092,334)				8.3.1

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 2025
Jim 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-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**
1 Structure, Equipment, Mine Dev.	258,367	252,145	252,017	251,731	252,253	252,179	252,156	239,342	240,419	240,419	244,425	244,438	245,124
2 Materials & Supplies	10,734	10,924	10,880	10,440	10,284	10,503	10,291	10,357	10,994	10,999	10,805	10,802	10,822
4 Pit Inventory	14,063	10,335	6,232	4,869	2,937	1,434	500	1,642	1,722	2,320	5,539	8,288	8,026
5 Deferred Long Wall Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
6 Reclamation Liability	-	-	-	-	-	-	-	-	-	-	-	-	-
7 Accumulated Depreciation	(215,293)	(209,924)	(210,742)	(211,392)	(212,290)	(213,162)	(213,997)	(201,599)	(202,304)	(203,018)	(203,811)	(204,513)	(205,233)
8 Bonus Bid / Lease Payable	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL RATE BASE	67,872	63,480	58,388	55,648	53,185	50,954	48,950	49,741	50,830	50,720	56,958	59,016	58,739
PacifiCorp Share (66.67%)	**45,248**	**42,320**	**38,925**	**37,098**	**35,457**	**33,969**	**32,633**	**33,161**	**33,886**	**33,814**	**37,972**	**39,344**	**39,159**

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 23**	**Jan 24**	**Feb 24**	**Mar 24**	**Apr 24**	**May 24**	**Jun 24**	**Jul 24**	**Aug 24**	**Sep 24**	**Oct 24**	**Nov 24**	**Dec 24**
1 Structure, Equipment, Mine Dev.	243,613	243,633	243,654	243,675	244,048	244,189	244,240	248,324	248,345	249,515	250,071	250,092	251,493
2 Materials & Supplies	10,943	10,963	10,984	11,004	11,024	11,044	11,065	11,085	11,105	11,125	11,145	11,166	11,186
4 Pit Inventory	818	350	-	-	2,531	2,928	1,069	174	796	1,273	2,272	2,054	1,196
5 Deferred Long Wall Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
6 Reclamation Liability	-	-	-	-	-	-	-	-	-	-	-	-	-
7 Accumulated Depreciation	(198,535)	(199,433)	(200,314)	(201,196)	(202,085)	(202,993)	(203,883)	(204,855)	(205,826)	(206,810)	(207,797)	(208,776)	(209,774)
8 Bonus Bid / Lease Payable	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL RATE BASE	56,840	55,513	54,323	53,483	55,518	55,169	52,491	54,727	54,420	55,103	55,692	54,536	54,101
PacifiCorp Share (66.67%)	**37,893**	**37,008**	**36,215**	**35,655**	**37,012**	**36,779**	**34,994**	**36,485**	**36,280**	**36,735**	**37,128**	**36,357**	**36,067**

June 2023 - End of Period Balance	**39,159**	**Ref 8.3**
December 2024 - End of Period Balance	**36,067**	**Ref 8.3**

PacifiCorp
Oregon General Rate Case - December 2025
Jim Bridger Mine Rate Base
Year End Balance

	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24
Materials & Supplies:													
Obsolete Reserve - Surface	(66,667)	(76,347)	(86,027)	(95,708)	(105,388)	(115,069)	(124,749)	(134,429)	(144,110)	(153,790)	(163,471)	(173,151)	(182,831)
Obsolete Reserve - Underground	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Obsolete Reserves	(66,667)	(76,347)	(86,027)	(95,708)	(105,388)	(115,069)	(124,749)	(134,429)	(144,110)	(153,790)	(163,471)	(173,151)	(182,831)
PacifiCorp's 2/3 share:													
Obsolete Reserve - Surface	(44,444)	(50,898)	(57,352)	(63,805)	(70,259)	(76,712)	(83,166)	(89,620)	(96,073)	(102,527)	(108,980)	(115,434)	(121,888)
Obsolete Reserve - Underground	-	-	-	-	-	-	-	-	-	-	-	-	-
Total of PacifiCorp's share of Obsolete Reserves	(44,444)	(50,898)	(57,352)	(63,805)	(70,259)	(76,712)	(83,166)	(89,620)	(96,073)	(102,527)	(108,980)	(115,434)	(121,888)

YE ADIT 190 Balance at December 31, 2023	**29,968**	
YE ADIT 190 Balance at June 30, 2023	-	Tax Model -Inventory Reserve - PMI - Account 287938
	29,968	**Ref 8.3**

PacifiCorp
Oregon General Rate Case - December 2025
Pro Forma Plant Additions and Retirements

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Steam Plant	312	3	(5,014,108)	SG	26.884%	(1,348,001)	
Steam Plant	312	3	(4,408,410)	SG	26.884%	(1,185,164)	
Steam Plant	312	3	122,977,984	SG	26.884%	33,061,594	
Steam Plant	312	3	-	SG	26.884%	-	
Hydro Plant	332	3	(715,350)	SG	26.884%	(192,316)	
Hydro Plant	332	3	(606,245)	SG	26.884%	(162,984)	
Hydro Plant	332	3	100,554,480	SG-P	26.884%	27,033,224	
Hydro Plant	332	3	30,397,797	SG-U	26.884%	8,172,191	
Other Plant	343	3	-	SG	26.884%	-	
Other Plant	343	3	14,039,163	SG	26.884%	3,774,311	
Other Plant	343	3	370,052	OR	Situs	370,052	
Other Plant	343	3	114,660,731	SG-W	26.884%	30,825,571	
Other Plant	343	3	(483,185)	SG	26.884%	(129,900)	
Transmission Plant	355	3	(3,387,388)	SG	26.884%	(910,671)	
Transmission Plant	355	3	(6,273,117)	SG	26.884%	(1,686,475)	
Transmission Plant	355	3	3,179,874,700	SG	26.884%	854,882,509	
Distribution Plant	360	3	7,948,417	OR	Situs	1,026,801	
Distribution Plant	361	3	15,247,731	OR	Situs	1,969,749	
Distribution Plant	362	3	127,960,167	OR	Situs	16,530,291	
Distribution Plant	363	3	-	OR	Situs	-	
Distribution Plant	364	3	157,527,513	OR	Situs	20,349,892	
Distribution Plant	365	3	98,675,281	OR	Situs	12,747,178	
Distribution Plant	366	3	50,096,878	OR	Situs	6,471,670	
Distribution Plant	367	3	114,106,094	OR	Situs	14,740,579	
Distribution Plant	368	3	166,580,965	OR	Situs	21,519,445	
Distribution Plant	369	3	106,267,280	OR	Situs	13,727,936	
Distribution Plant	370	3	30,143,458	OR	Situs	3,894,025	
Distribution Plant	371	3	911,194	OR	Situs	117,711	
Distribution Plant	372	3	-	OR	Situs	-	
Distribution Plant	373	3	6,489,363	OR	Situs	838,316	
General Plant	397	3	995,508	CA	Situs	-	
General Plant	397	3	60,522,889	OR	Situs	60,522,889	
General Plant	397	3	4,551,009	WA	Situs	-	
General Plant	397	3	8,207,455	WYP	Situs	-	
General Plant	397	3	23,690,756	UT	Situs	-	
General Plant	397	3	2,825,846	ID	Situs	-	
General Plant	397	3	(437,152)	WYU	Situs	-	
General Plant	397	3	(164,438)	SG	26.884%	(44,208)	
General Plant	397	3	(486,722)	SG	26.884%	(130,851)	
General Plant	397	3	(9,765,676)	SG	26.884%	(2,625,420)	
General Plant	397	3	69,872,687	SO	27.425%	19,162,910	
General Plant	397	3	-	SG	26.884%	-	
General Plant	397	3	(1,212)	SG	26.884%	(326)	
General Plant	397	3	(1,924,775)	CN	30.706%	(591,012)	
General Plant	397	3	(200,734)	SE	26.339%	(52,871)	
Mining Plant	399	3	-	SE	26.339%	-	
			4,581,626,886			1,142,678,647	

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, 2024. This adjustment includes the year end balance for plant additions that will be placed into service by December 31, 2024. 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 8.4.30 through 8.4.36. Retirements of plant in service are also walked forward through the test period. This adjustment includes the repowering retirements. This adjustment reflects the net impact of capital additions, and retirements.

The tax portion of this adjustment represents the tax impacts of the difference between 2024 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 PAGE 8.4.1
Oregon General Rate Case - December 2025
(cont.) Pro Forma Plant Additions and Retirements

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Intangible Plant	303	3	(174)	CA	Situs	-	
Intangible Plant	303	3	(2,466,028)	CN	30.706%	(757,207)	
Intangible Plant	302	3	(37,019)	SG	26.884%	(9,952)	
Intangible Plant	302	3	-	SG	26.884%	-	
Intangible Plant	303	3	(518)	ID	Situs	-	
Intangible Plant	303	3	(7,244)	OR	Situs	(7,244)	
Intangible Plant	303	3	(4,396)	SE	26.339%	(1,158)	
Intangible Plant	302	3	3,164,691	SG	26.884%	850,800	
Intangible Plant	302	3	(83,981)	SG-P	26.884%	(22,577)	
Intangible Plant	302	3	(268,568)	SG-U	26.884%	(72,202)	
Intangible Plant	303	3	-	SG	26.884%	-	
Intangible Plant	303	3	211,805,799	SO	27.425%	58,088,727	
Intangible Plant	303	3	(5,426)	UT	Situs	-	
Intangible Plant	303	3	-	WA	Situs	-	
Intangible Plant	303	3	(47,298)	WYP	Situs	-	
Intangible Plant	303	3	-	WYU	Situs	-	
			212,049,837			58,069,186	
Total Adjustment			4,793,676,722			1,200,747,833	8.4.4
Adjustments to Tax:							
Schedule M Additions	SCHMAT	3	(73,182)	OR	Situs	(73,182)	
Schedule M Additions	SCHMAT	3	(1,759,167)	SG	26.884%	(472,937)	
Schedule M Deductions	SCHMDT	3	(234,676)	OR	Situs	(234,676)	
Schedule M Deductions	SCHMDT	3	(2,729,658)	SG	26.884%	(733,846)	
Deferred Tax Expense	41110	3	17,993	OR	Situs	17,993	
Deferred Tax Expense	41110	3	432,529	SG	26.884%	116,282	
Deferred Tax Expense	41010	3	(57,698)	OR	Situs	(57,698)	
Deferred Tax Expense	41010	3	(671,131)	SG	26.884%	(180,428)	
Accum. Def. Inc. Tax. Bal.	282	3	68,628	OR	Situs	68,628	
Accum. Def. Inc. Tax. Bal.	282	3	276,524	SG	26.884%	74,341	
Sch M-2024 Annualized Book Depr	SCHMAT	3	16,498	OR	Situs	16,498	
Sch M-2024 Annualized Book Depr	SCHMAT	3	1,320,246	SG	26.884%	354,937	
Def Tax Exp-2024 Annualized Book Depr	41110	3	(4,056)	OR	Situs	(4,056)	
Def Tax Exp-2024 Annualized Book Depr	41110	3	(324,604)	SG	26.884%	(87,267)	
Accum. Def. Inc. Tax. Bal.	282	3	4,056	OR	Situs	4,056	
Accum. Def. Inc. Tax. Bal.	282	3	324,604	SG	26.884%	87,267	

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, 2024. This adjustment includes the year end balance for plant additions that will be placed into service by December 31, 2024. 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 8.4.30 through 8.4.36. Retirements of plant in service are also walked forward through the test period. This adjustment includes the repowering retirements. This adjustment reflects the net impact of capital additions, and retirements.

The tax portion of this adjustment represents the tax impacts of the difference between 2024 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 2025
(cont.) Pro Forma Plant Additions and Retirements

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustments to Tax:							
Sch. M Addition - Increm. Book Depr.	SCHMAT	3	42,849,398	SG	26.884%	11,519,699	
Sch. M Addition - Increm. Book Depr.	SCHMAT	3	1,983,910	OR	Situs	1,983,910	
Sch. M Addition - Increm. Book Depr.	SCHMAT	3	11,925,637	SO	27.425%	3,270,662	
Sch. M Addition - Increm. Book Depr.	SCHMAT	3	3,375,839	CA	Situs	-	
Sch. M Addition - Increm. Book Depr.	SCHMAT	3	(88,778)	CN	30.706%	(27,260)	
Sch. M Addition - Increm. Book Depr.	SCHMAT	3	4,527,450	UT	Situs	-	
Sch. M Addition - Increm. Book Depr.	SCHMAT	3	573,109	WA	Situs	-	
Sch. M Addition - Increm. Book Depr.	SCHMAT	3	501,230	WYP	Situs	-	
Sch. M Addition - Increm. Book Depr.	SCHMAT	3	(10,301)	WYU	Situs	-	
Sch. M Addition - Increm. Book Depr.	SCHMAT	3	346,596	ID	Situs	-	
Sch. M Addition - Increm. Book Depr.	SCHMAT	3	(2,690)	SE	26.339%	(709)	
			65,981,400			16,746,303	
DIT Exp - Increm. Book Depr.	41110	3	(10,535,210)	SG	26.884%	(2,832,302)	
DIT Exp - Increm. Book Depr.	41110	3	(487,776)	OR	Situs	(487,776)	
DIT Exp - Increm. Book Depr.	41110	3	(2,932,109)	SO	27.425%	(804,144)	
DIT Exp - Increm. Book Depr.	41110	3	(830,004)	CA	Situs	-	
DIT Exp - Increm. Book Depr.	41110	3	21,827	CN	30.706%	6,702	
DIT Exp - Increm. Book Depr.	41110	3	(1,113,146)	UT	Situs	-	
DIT Exp - Increm. Book Depr.	41110	3	(140,908)	WA	Situs	-	
DIT Exp - Increm. Book Depr.	41110	3	(123,235)	WYP	Situs	-	
DIT Exp - Increm. Book Depr.	41110	3	2,533	WYU	Situs	-	
DIT Exp - Increm. Book Depr.	41110	3	(85,216)	ID	Situs	-	
DIT Exp - Increm. Book Depr.	41110	3	661	SE	26.339%	174	
			(16,222,583)			(4,117,346)	
ADIT - Increm. Book Depr.	282	3	10,535,210	SG	26.884%	2,832,302	
ADIT - Increm. Book Depr.	282	3	487,776	OR	Situs	487,776	
ADIT - Increm. Book Depr.	282	3	2,932,109	SO	27.425%	804,144	
ADIT - Increm. Book Depr.	282	3	830,004	CA	Situs	-	
ADIT - Increm. Book Depr.	282	3	(21,827)	CN	30.706%	(6,702)	
ADIT - Increm. Book Depr.	282	3	1,113,146	UT	Situs	-	
ADIT - Increm. Book Depr.	282	3	140,908	WA	Situs	-	
ADIT - Increm. Book Depr.	282	3	123,235	WYP	Situs	-	
ADIT - Increm. Book Depr.	282	3	(2,533)	WYU	Situs	-	
ADIT - Increm. Book Depr.	282	3	85,216	ID	Situs	-	
ADIT - Increm. Book Depr.	282	3	(661)	SE	26.339%	(174)	
			16,222,583			4,117,346	

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, 2024. This adjustment includes the year end balance for plant additions that will be placed into service by December 31, 2024. 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 8.4.30 through 8.4.36. Retirements of plant in service are also walked forward through the test period. This adjustment includes the repowering retirements. This adjustment reflects the net impact of capital additions, and retirements.

The tax portion of this adjustment represents the tax impacts of the difference between 2024 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 2025
Pro Forma Plant Additions and Retirements

Description	FERC Account	Factor	End of Period June 2023 EPIS Balance	Test Period EPIS Balance Year End 2024	Adjustment to Test Period
Steam Production Plant:					
Pre-merger Pacific	312	SG	1,008,703,226	1,003,689,118	(5,014,108)
Pre-merger Utah	312	SG	1,051,760,466	1,047,352,057	(4,408,410)
Pollution Control	312	SG	-	1,336,526	1,336,526
Post-merger	312	SG	4,956,941,807	5,048,221,722	91,279,915
Post-merger-Renewable	313	SG	-	30,361,542	30,361,542
Post-merger-Cholla	312	SG	1,266,851	1,266,851	-
Total Steam Plant			7,018,672,351	7,132,227,816	113,555,466
Hydro Production Plant:					
Pre-merger Pacific	332	SG	183,725,898	183,010,548	(715,350)
Pre-merger Utah	332	SG	39,600,570	38,994,324	(606,245)
Post-merger	332	SG-P	678,335,858	778,890,338	100,554,480
Post-merger	332	SG-U	165,769,344	196,167,141	30,397,797
Total Hydro Plant			1,067,431,670	1,197,062,350	129,630,681
Other Production Plant:					
Pre-merger Utah	343	SG	235,129	235,129	-
Post-merger	343	SG	1,944,497,799	1,958,536,962	14,039,163
Post-merger Wind	343	SG-W	3,225,445,773	3,340,106,504	114,660,731
Post-merger	343	SG	88,883,413	88,400,228	(483,185)
Oregon Solar	343	OR	595,308	965,360	370,052
Total Other Production Plant			5,259,657,422	5,388,244,183	128,586,761
Transmission Plant:					
Pre-merger Pacific	355	SG	474,654,963	471,267,575	(3,387,388)
Pre-merger Utah	355	SG	611,506,343	605,233,226	(6,273,117)
Post-merger	355	SG	7,002,292,488	10,182,167,188	3,179,874,700
Total Transmission Plant			8,088,453,794	11,258,667,989	3,170,214,195
Distribution Plant:					
California	360-373	CA	387,052,668	576,351,800	189,299,132
Oregon	360-373	OR	2,591,555,458	2,705,489,051	113,933,593
Washington	360-373	WA	626,391,983	662,561,779	36,169,796
Eastern Wyoming	360-373	WYP	741,523,302	775,671,204	34,147,901
Utah	360-373	UT	3,731,611,811	4,206,065,758	474,453,946
Idaho	360-373	ID	434,569,369	469,339,885	34,770,517
Western Wyoming	360-373	WYU	153,080,209	152,259,664	(820,545)
Total Distribution Plant			8,665,784,800	9,547,739,141	881,954,341

PacifiCorp
Oregon General Rate Case - December 2025
Pro Forma Plant Additions and Retirements

Description	FERC Account	Factor	End of Period June 2023 EPIS Balance	Test Period EPIS Balance Year End 2024	Adjustment to Test Period
General Plant:					
California	397	CA	23,405,890	24,401,398	995,508
Oregon	397	OR	225,581,526	286,104,415	60,522,889
Washington	397	WA	51,472,188	56,023,197	4,551,009
Eastern Wyoming	397	WYP	101,695,396	109,902,851	8,207,455
Utah	397	UT	284,345,700	308,036,456	23,690,756
Idaho	397	ID	58,263,050	61,088,897	2,825,846
Western Wyoming	397	WYU	20,825,570	20,388,418	(437,152)
Pre-merger Pacific	397	SG	691,832	527,395	(164,438)
Pre-merger Utah	397	SG	2,903,299	2,416,577	(486,722)
Post-merger	397	SG	333,494,863	323,729,187	(9,765,676)
General Office	397	SO	378,098,762	447,971,449	69,872,687
General Office	397	SG	-	-	-
General Office	397	SG	227,520	226,308	(1,212)
Customer Service	397	CN	15,746,220	13,821,444	(1,924,775)
Fuel Related	397	SE	3,349,862	3,149,128	(200,734)
Total General Plant			1,500,101,679	1,657,787,121	157,685,441
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	472,341	472,167	(174)
Customer Service	303	CN	231,939,839	229,473,811	(2,466,028)
Pre-merger Utah	302	SG	477,596	440,577	(37,019)
Pre-merger Pacific	302	SG	-	-	-
Idaho	303	ID	4,356,591	4,356,073	(518)
Oregon	303	OR	4,613,651	4,606,407	(7,244)
Fuel Related	303	SE	9,106	4,710	(4,396)
Post-merger	302	SG	203,828,859	206,993,550	3,164,691
Hydro Relicensing	302	SG-P	103,455,075	103,371,094	(83,981)
Hydro Relicensing	302	SG-U	10,024,217	9,755,649	(268,568)
Post-merger	303	SG	-	-	-
General Office	303	SO	489,268,951	701,074,750	211,805,799
Utah	303	UT	7,525,664	7,520,237	(5,426)
Washington	303	WA	2,021,868	2,021,868	-
Eastern Wyoming	303	WYP	5,349,853	5,302,554	(47,298)
Western Wyoming	303	WYU	-	-	-
Total Intangible Plant			1,063,343,611	1,275,393,448	212,049,837
Total EPIS Balance			**32,665,268,227**	**37,458,944,949**	**4,793,676,722**
			Ref. 8.4.6	**Ref. 8.4.18**	**Ref 8.4.1**

PacifiCorp
Oregon General Rate Case - December 2025
Pro Forma Plant Additions
and Retirements

Description	Factor	Adjusted EPIS Balance Jun 2023	Capital Additions	Retirements	Adjusted EPIS Balance Jul 2023	Capital Additions	Retirements	Adjusted EPIS Balance Aug 2023	Capital Additions	Retirements
Steam Production Plant:										
Pre-merger Pacific	SG	1,008,703,226	-	(278,562)	1,008,424,665	-	(278,562)	1,008,146,103	-	(278,562)
Pre-merger Utah	SG	1,051,760,466	-	(244,912)	1,051,515,555	-	(244,912)	1,051,270,643	-	(244,912)
Post-merger	SG	4,926,894,994	3,232,910	(3,316,963)	4,926,810,940	4,647,259	(3,316,963)	4,928,141,236	39,412,442	(3,316,963)
Geothermal - Blundell	SG	30,046,813	-	-	30,046,813	-	-	30,046,813	-	-
Pollution Control Equipment	SG	-	168,873	-	168,873	-	-	168,873	-	-
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-
Post-merger - Cholla	SG	1,266,851	-	-	1,266,851	-	-	1,266,851	-	-
Total Steam Plant		7,018,672,351	3,401,783	(3,840,437)	7,018,233,697	4,647,259	(3,840,437)	7,019,040,519	39,412,442	(3,840,437)
Hydro Production Plant:										
Pre-merger Pacific	SG	183,725,898	-	(39,742)	183,686,156	-	(39,742)	183,646,415	-	(39,742)
Pre-merger Utah	SG	39,600,570	-	(33,680)	39,566,890	-	(33,680)	39,533,209	-	(33,680)
Post-merger	SG-P	678,335,858	2,185,450	(233,011)	680,288,298	1,638,548	(233,011)	681,693,835	3,256,035	(233,011)
Post-merger	SG-U	165,769,344	(81,640)	(50,023)	165,637,680	133,265	(50,023)	165,720,922	70,268	(50,023)
Klamath	SG-P	-	-	-	-	-	-	-	-	-
Total Hydro Plant		1,067,431,670	2,103,810	(356,456)	1,069,179,024	1,771,813	(356,456)	1,070,594,381	3,326,303	(356,456)
Other Production Plant:										
Pre-merger Utah	SG	235,129	-	-	235,129	-	-	235,129	-	-
Post-merger	SG	1,944,497,799	(89,473)	(1,912,485)	1,942,495,841	(136,702)	(1,912,485)	1,940,446,654	(136,702)	(1,912,485)
Post-merger Wind	SG-W	3,225,445,773	399,849	(45,518)	3,225,800,105	1,134,452	(45,518)	3,226,889,040	1,518,245	(45,518)
Black Cap Solar	OR	595,308	125,080	-	720,388	124,887	-	845,275	-	-
Post-merger	SG	88,883,413	-	(66,123)	88,817,290	-	(66,123)	88,751,167	-	(66,123)
Total Other Plant		5,259,657,422	435,457	(2,024,126)	5,258,068,753	1,122,638	(2,024,126)	5,257,167,266	1,381,543	(2,024,126)
Transmission Plant:										
Pre-merger Pacific	SG	474,654,963	-	(188,188)	474,466,774	-	(188,188)	474,278,586	-	(188,188)
Pre-merger Utah	SG	611,506,343	-	(348,507)	611,157,837	-	(348,507)	610,809,330	-	(348,507)
Post-merger	SG	7,002,292,488	18,548,023	(1,092,514)	7,019,747,997	24,468,106	(1,092,514)	7,043,123,588	11,856,156	(1,092,514)
Total Transmission Plant		8,088,453,794	18,548,023	(1,629,209)	8,105,372,608	24,468,106	(1,629,209)	8,128,211,505	11,856,156	(1,629,209)
Distribution Plant:										
California	CA	387,052,668	3,817,919	(210,964)	390,659,622	3,678,669	(210,964)	394,127,327	14,376,989	(210,964)
Oregon	OR	2,591,555,458	7,014,253	(1,899,184)	2,596,670,527	8,856,693	(1,899,184)	2,603,628,036	20,455,510	(1,899,184)
Washington	WA	626,391,983	3,082,335	(223,044)	629,251,275	3,425,370	(223,044)	632,453,601	654,572	(223,044)
Eastern Wyoming	WYP	741,523,302	1,456,142	(291,286)	742,688,158	2,804,915	(291,286)	745,201,787	1,636,201	(291,286)
Utah	UT	3,731,611,811	21,073,471	(1,981,491)	3,750,703,791	22,734,635	(1,981,491)	3,771,456,936	13,823,272	(1,981,491)
Idaho	ID	434,569,369	2,635,574	(432,996)	436,771,948	1,835,172	(432,996)	438,174,124	1,899,599	(432,996)
Western Wyoming	WYU	153,080,209	-	(45,586)	153,034,623	-	(45,586)	152,989,037	-	(45,586)
Total Distribution Plant		8,665,784,800	39,079,694	(5,084,550)	8,699,779,944	43,335,453	(5,084,550)	8,738,030,847	52,846,144	(5,084,550)

PacifiCorp
Oregon General Rate Case - December 2025
Pro Forma Plant Additions
and Retirements

Description	Factor	Adjusted EPIS Balance Jun 2023	Capital Additions	Retirements	Adjusted EPIS Balance Jul 2023	Capital Additions	Retirements	Adjusted EPIS Balance Aug 2023	Capital Additions	Retirements
General Plant:										
California	CA	23,405,890	73,358	(58,368)	23,420,880	10,924	(58,368)	23,373,436	55,379	(58,368)
Oregon	OR	225,581,526	1,754,424	(612,056)	226,723,894	1,114,323	(612,056)	227,226,161	1,586,889	(612,056)
Washington	WA	51,472,188	355,369	(108,683)	51,718,875	35,398	(108,683)	51,645,591	66,732	(108,683)
Eastern Wyoming	WYP	101,695,396	149,328	(183,824)	101,660,900	311,194	(183,824)	101,788,270	191,269	(183,824)
Utah	UT	284,345,700	4,617,165	(431,850)	288,531,016	2,400,025	(431,850)	290,499,191	1,527,569	(431,850)
Idaho	ID	58,263,050	53,396	(81,668)	58,234,778	341,303	(81,668)	58,494,412	106,139	(81,668)
Western Wyoming	WYU	20,825,570	-	(24,286)	20,801,284	-	(24,286)	20,776,998	-	(24,286)
Pre-merger Pacific	SG	691,832	-	(9,135)	682,697	-	(9,135)	673,562	-	(9,135)
Pre-merger Utah	SG	2,903,299	-	(27,040)	2,876,259	-	(27,040)	2,849,219	-	(27,040)
Post-merger	SG	333,494,863	13,612	(626,721)	332,881,755	28,195	(626,721)	332,283,229	43,273	(626,721)
General Office	SO	378,098,762	2,138,856	(1,386,364)	378,851,254	1,418,837	(1,386,364)	378,883,727	6,632,056	(1,386,364)
General Office	SG	-	-	-	-	-	-	-	-	-
General Office	SG	227,520	-	(67)	227,452	-	(67)	227,385	-	(67)
Customer Service	CN	15,746,220	-	(106,932)	15,639,288	-	(106,932)	15,532,356	-	(106,932)
Fuel Related	SE	3,349,862	-	(11,152)	3,338,710	-	(11,152)	3,327,558	-	(11,152)
Total General Plant		1,500,101,679	9,155,509	(3,668,146)	1,505,589,042	5,660,199	(3,668,146)	1,507,581,095	10,209,306	(3,668,146)
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	472,341	-	(10)	472,331	-	(10)	472,322	-	(10)
Customer Service	CN	231,939,839	-	(137,002)	231,802,837	-	(137,002)	231,665,836	-	(137,002)
Pre-merger Utah	SG	477,596	-	(2,057)	475,540	-	(2,057)	473,483	-	(2,057)
Pre-merger Pacific	SG	-	-	-	-	-	-	-	-	-
Idaho	ID	4,356,591	-	(29)	4,356,562	-	(29)	4,356,533	-	(29)
Oregon	OR	4,613,651	-	(402)	4,613,249	-	(402)	4,612,846	-	(402)
Fuel Related	SE	9,106	-	(244)	8,862	-	(244)	8,617	-	(244)
Post-merger	SG	207,905,089	-	(50,641)	207,854,448	-	(50,641)	207,803,807	-	(50,641)
Klamath Hydro Relicensing	SG-P	-	-	-	-	-	-	-	-	-
Hydro Relicensing	SG-P	103,455,075	-	(4,666)	103,450,409	-	(4,666)	103,445,744	-	(4,666)
Hydro Relicensing	SG-U	10,024,217	-	(14,920)	10,009,296	-	(14,920)	9,994,376	-	(14,920)
General Office	SO	485,192,721	307,222	(641,843)	484,858,100	6,845,489	(641,843)	491,061,747	3,816,307	(641,843)
Utah	UT	7,525,664	-	(301)	7,525,362	-	(301)	7,525,061	-	(301)
Washington	WA	2,021,868	-	-	2,021,868	-	-	2,021,868	-	-
Eastern Wyoming	WYP	5,349,853	-	(2,628)	5,347,225	-	(2,628)	5,344,598	-	(2,628)
Western Wyoming	WYU	-	-	-	-	-	-	-	-	-
Total Intangible Plant		1,063,343,611	307,222	(854,742)	1,062,796,091	6,845,489	(854,742)	1,068,786,838	3,816,307	(854,742)
Total		**32,665,268,227**	73,031,498	(17,457,665)	32,720,842,060	87,850,957	(17,457,665)	32,791,235,351	122,848,200	(17,457,665)
		Ref 8.4.4								

PacifiCorp
Oregon General Rate Case - December 2025
Pro Forma Plant Additions
and Retirements

Description	Factor	Adjusted EPIS Balance Sep 2023	Capital Additions	Retirements	Adjusted EPIS Balance Oct 2023	Capital Additions	Retirements	Adjusted EPIS Balance Nov 2023	Capital Additions	Retirements
Steam Production Plant:										
Pre-merger Pacific	SG	1,007,867,542	-	(278,562)	1,007,588,980	-	(278,562)	1,007,310,418	-	(278,562)
Pre-merger Utah	SG	1,051,025,732	-	(244,912)	1,050,780,820	-	(244,912)	1,050,535,908	-	(244,912)
Post-merger	SG	4,964,236,714	3,521,646	(3,316,963)	4,964,441,397	10,795,536	(3,316,963)	4,971,919,969	18,343,936	(3,316,963)
Geothermal - Blundell	SG	30,046,813	-	-	30,046,813	-	-	30,046,813	51,400	-
Pollution Control Equipment	SG	168,873	-	-	168,873	119,106	-	287,979	514,019	-
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-
Post-merger - Cholla	SG	1,266,851	-	-	1,266,851	-	-	1,266,851	-	-
Total Steam Plant		7,054,612,524	3,521,646	(3,840,437)	7,054,293,733	10,914,642	(3,840,437)	7,061,367,939	18,909,356	(3,840,437)
Hydro Production Plant:										
Pre-merger Pacific	SG	183,606,673	-	(39,742)	183,566,931	-	(39,742)	183,527,190	-	(39,742)
Pre-merger Utah	SG	39,499,529	-	(33,680)	39,465,849	-	(33,680)	39,432,168	-	(33,680)
Post-merger	SG-P	684,716,859	3,008,320	(233,011)	687,492,168	2,494,636	(233,011)	689,753,794	14,901,830	(233,011)
Post-merger	SG-U	165,741,167	58,602	(50,023)	165,749,745	454,850	(50,023)	166,154,572	4,935,491	(50,023)
Klamath	SG-P	-	-	-	-	1,412,738	-	1,412,738	-	-
Total Hydro Plant		1,073,564,228	3,066,922	(356,456)	1,076,274,694	4,362,224	(356,456)	1,080,280,462	19,837,321	(356,456)
Other Production Plant:										
Pre-merger Utah	SG	235,129	-	-	235,129	-	-	235,129	-	-
Post-merger	SG	1,938,397,467	37,039,548	(1,912,485)	1,973,524,530	1,220,312	(1,912,485)	1,972,832,356	6,218,017	(1,912,485)
Post-merger Wind	SG-W	3,228,361,767	1,631,653	(45,518)	3,229,947,903	81,175,879	(45,518)	3,311,078,264	5,081,995	(45,518)
Black Cap Solar	OR	845,275	-	-	845,275	-	-	845,275	20,958	-
Post-merger	SG	88,685,045	76,941	(66,123)	88,695,863	233,233	(66,123)	88,862,973	52,101	(66,123)
Total Other Plant		5,256,524,683	38,748,142	(2,024,126)	5,293,248,700	82,629,423	(2,024,126)	5,373,853,997	11,373,071	(2,024,126)
Transmission Plant:										
Pre-merger Pacific	SG	474,090,398	-	(188,188)	473,902,210	-	(188,188)	473,714,022	-	(188,188)
Pre-merger Utah	SG	610,460,824	-	(348,507)	610,112,317	-	(348,507)	609,763,811	-	(348,507)
Post-merger	SG	7,053,887,230	21,886,956	(1,092,514)	7,074,681,672	34,933,727	(1,092,514)	7,108,522,884	70,640,347	(1,092,514)
Total Transmission Plant		8,138,438,452	21,886,956	(1,629,209)	8,158,696,199	34,933,727	(1,629,209)	8,192,000,716	70,640,347	(1,629,209)
Distribution Plant:										
California	CA	408,293,351	13,702,547	(210,964)	421,784,934	8,534,134	(210,964)	430,108,104	5,915,002	(210,964)
Oregon	OR	2,622,184,362	7,159,143	(1,899,184)	2,627,444,321	6,279,023	(1,899,184)	2,631,824,160	13,174,142	(1,899,184)
Washington	WA	632,885,130	539,717	(223,044)	633,201,803	400,283	(223,044)	633,379,043	516,973	(223,044)
Eastern Wyoming	WYP	746,546,702	1,364,516	(291,286)	747,619,932	1,737,583	(291,286)	749,066,229	1,725,775	(291,286)
Utah	UT	3,783,298,717	24,921,196	(1,981,491)	3,806,238,422	30,626,088	(1,981,491)	3,834,883,019	72,377,659	(1,981,491)
Idaho	ID	439,640,727	1,528,686	(432,996)	440,736,417	1,471,007	(432,996)	441,774,428	1,425,090	(432,996)
Western Wyoming	WYU	152,943,451	-	(45,586)	152,897,866	-	(45,586)	152,852,280	-	(45,586)
Total Distribution Plant		8,785,792,440	49,215,805	(5,084,550)	8,829,923,695	49,048,117	(5,084,550)	8,873,887,262	95,134,641	(5,084,550)

PacifiCorp
Oregon General Rate Case - December 2025
Pro Forma Plant Additions
and Retirements

Description	Factor	Adjusted EPIS Balance Sep 2023	Capital Additions	Retirements	Adjusted EPIS Balance Oct 2023	Capital Additions	Retirements	Adjusted EPIS Balance Nov 2023	Capital Additions	Retirements
General Plant:										
California	CA	23,370,448	72,685	(58,368)	23,384,765	47,392	(58,368)	23,373,789	74,471	(58,368)
Oregon	OR	228,200,995	3,293,044	(612,056)	230,881,984	2,824,155	(612,056)	233,094,083	3,756,537	(612,056)
Washington	WA	51,603,640	625,946	(108,683)	52,120,903	600,653	(108,683)	52,612,874	627,732	(108,683)
Eastern Wyoming	WYP	101,795,715	259,018	(183,824)	101,870,909	4,196,635	(183,824)	105,883,720	524,627	(183,824)
Utah	UT	291,594,910	1,039,743	(431,850)	292,202,804	1,068,149	(431,850)	292,839,103	4,428,399	(431,850)
Idaho	ID	58,518,883	177,830	(81,668)	58,615,045	177,903	(81,668)	58,711,279	503,106	(81,668)
Western Wyoming	WYU	20,752,712	-	(24,286)	20,728,425	-	(24,286)	20,704,139	-	(24,286)
Pre-merger Pacific	SG	664,426	-	(9,135)	655,291	-	(9,135)	646,155	-	(9,135)
Pre-merger Utah	SG	2,822,179	-	(27,040)	2,795,139	-	(27,040)	2,768,099	-	(27,040)
Post-merger	SG	331,699,782	67,296	(626,721)	331,140,357	621,455	(626,721)	331,135,091	400,393	(626,721)
General Office	SO	384,129,419	7,328,692	(1,386,364)	390,071,746	4,103,746	(1,386,364)	392,789,128	8,049,929	(1,386,364)
General Office	SG	-	-	-	-	-	-	-	-	-
General Office	SG	227,318	-	(67)	227,251	-	(67)	227,183	-	(67)
Customer Service	CN	15,425,424	-	(106,932)	15,318,492	-	(106,932)	15,211,560	-	(106,932)
Fuel Related	SE	3,316,406	-	(11,152)	3,305,254	-	(11,152)	3,294,102	-	(11,152)
Total General Plant		1,514,122,256	12,864,254	(3,668,146)	1,523,318,364	13,640,088	(3,668,146)	1,533,290,306	18,365,194	(3,668,146)
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	472,312	-	(10)	472,302	-	(10)	472,293	-	(10)
Customer Service	CN	231,528,834	-	(137,002)	231,391,833	-	(137,002)	231,254,831	-	(137,002)
Pre-merger Utah	SG	471,427	-	(2,057)	469,370	-	(2,057)	467,313	-	(2,057)
Pre-merger Pacific	SG	-	-	-	-	-	-	-	-	-
Idaho	ID	4,356,505	-	(29)	4,356,476	-	(29)	4,356,447	-	(29)
Oregon	OR	4,612,444	-	(402)	4,612,041	-	(402)	4,611,639	-	(402)
Fuel Related	SE	8,373	-	(244)	8,129	-	(244)	7,885	-	(244)
Post-merger	SG	207,753,166	-	(50,641)	207,702,525	-	(50,641)	207,651,884	-	(50,641)
Klamath Hydro Relicensing	SG-P	-	-	-	-	-	-	-	-	-
Hydro Relicensing	SG-P	103,441,078	-	(4,666)	103,436,412	-	(4,666)	103,431,747	-	(4,666)
Hydro Relicensing	SG-U	9,979,455	-	(14,920)	9,964,535	-	(14,920)	9,949,615	-	(14,920)
General Office	SO	494,236,211	2,933,171	(641,843)	496,527,539	558,547	(641,843)	496,444,244	3,282,742	(641,843)
Utah	UT	7,524,759	-	(301)	7,524,458	-	(301)	7,524,157	-	(301)
Washington	WA	2,021,868	-	-	2,021,868	-	-	2,021,868	-	-
Eastern Wyoming	WYP	5,341,970	-	(2,628)	5,339,342	-	(2,628)	5,336,714	-	(2,628)
Western Wyoming	WYU	-	-	-	-	-	-	-	-	-
Total Intangible Plant		1,071,748,403	2,933,171	(854,742)	1,073,826,831	558,547	(854,742)	1,073,530,636	3,282,742	(854,742)
Total		32,896,625,886	132,236,896	(17,457,665)	33,011,405,116	196,086,768	(17,457,665)	33,190,034,219	237,542,672	(17,457,665)

PacifiCorp
Oregon General Rate Case - December 2025
Pro Forma Plant Additions
and Retirements

Description	Factor	Adjusted EPIS Balance Dec 2023	Capital Additions	Retirements	Adjusted EPIS Balance Jan 2024	Capital Additions	Retirements	Adjusted EPIS Balance Feb 2024	Capital Additions	Retirements
Steam Production Plant:										
Pre-merger Pacific	SG	1,007,031,857	-	(278,562)	1,006,753,295	-	(278,562)	1,006,474,734	-	(278,562)
Pre-merger Utah	SG	1,050,290,997	-	(244,912)	1,050,046,085	-	(244,912)	1,049,801,173	-	(244,912)
Post-merger	SG	4,986,946,942	1,086,088	(3,316,963)	4,984,716,067	1,233,438	(3,316,963)	4,982,632,541	6,319,429	(3,316,963)
Geothermal - Blundell	SG	30,098,213	13,354	-	30,111,567	13,354	-	30,124,921	13,354	-
Pollution Control Equipment	SG	801,998	-	-	801,998	-	-	801,998	-	-
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-
Post-merger - Cholla	SG	1,266,851	-	-	1,266,851	-	-	1,266,851	-	-
Total Steam Plant		7,076,436,858	1,099,442	(3,840,437)	7,073,695,864	1,246,792	(3,840,437)	7,071,102,219	6,332,783	(3,840,437)
Hydro Production Plant:										
Pre-merger Pacific	SG	183,487,448	-	(39,742)	183,447,706	-	(39,742)	183,407,965	-	(39,742)
Pre-merger Utah	SG	39,398,488	-	(33,680)	39,364,808	-	(33,680)	39,331,127	-	(33,680)
Post-merger	SG-P	704,422,613	(63,998)	(233,011)	704,125,604	(63,998)	(233,011)	703,828,595	37,422,230	(233,011)
Post-merger	SG-U	171,040,040	(81,640)	(50,023)	170,908,376	(81,640)	(50,023)	170,776,713	(3,060)	(50,023)
Klamath	SG-P	1,412,738	-	-	1,412,738	-	-	1,412,738	-	-
Total Hydro Plant		1,099,761,327	(145,638)	(356,456)	1,099,259,233	(145,638)	(356,456)	1,098,757,138	37,419,170	(356,456)
Other Production Plant:										
Pre-merger Utah	SG	235,129	-	-	235,129	-	-	235,129	-	-
Post-merger	SG	1,977,137,888	(58,683)	(1,912,485)	1,975,166,719	(58,683)	(1,912,485)	1,973,195,550	(58,683)	(1,912,485)
Post-merger Wind	SG-W	3,316,114,741	1,401,569	(45,518)	3,317,470,792	993,243	(45,518)	3,318,418,517	3,923,763	(45,518)
Black Cap Solar	OR	866,233	-	-	866,233	-	-	866,233	-	-
Post-merger	SG	88,848,951	4,528	(66,123)	88,787,357	4,528	(66,123)	88,725,762	4,528	(66,123)
Total Other Plant		5,383,202,942	1,347,413	(2,024,126)	5,382,526,230	939,087	(2,024,126)	5,381,441,192	3,869,607	(2,024,126)
Transmission Plant:										
Pre-merger Pacific	SG	473,525,833	-	(188,188)	473,337,645	-	(188,188)	473,149,457	-	(188,188)
Pre-merger Utah	SG	609,415,304	-	(348,507)	609,066,798	-	(348,507)	608,718,291	-	(348,507)
Post-merger	SG	7,178,070,717	10,998,299	(1,092,514)	7,187,976,501	61,295,924	(1,092,514)	7,248,179,911	14,623,456	(1,092,514)
Total Transmission Plant		8,261,011,854	10,998,299	(1,629,209)	8,270,380,944	61,295,924	(1,629,209)	8,330,047,659	14,623,456	(1,629,209)
Distribution Plant:										
California	CA	435,812,141	722,177	(210,964)	436,323,354	950,403	(210,964)	437,062,793	3,042,360	(210,964)
Oregon	OR	2,643,099,119	2,959,185	(1,899,184)	2,644,159,119	5,607,698	(1,899,184)	2,647,867,634	9,492,982	(1,899,184)
Washington	WA	633,672,972	849,148	(223,044)	634,299,077	902,746	(223,044)	634,978,779	2,400,329	(223,044)
Eastern Wyoming	WYP	750,500,718	1,261,213	(291,286)	751,470,645	1,416,424	(291,286)	752,595,783	1,732,529	(291,286)
Utah	UT	3,905,279,188	14,312,928	(1,981,491)	3,917,610,625	19,010,773	(1,981,491)	3,934,639,907	19,371,514	(1,981,491)
Idaho	ID	442,766,522	1,240,005	(432,996)	443,573,532	1,292,637	(432,996)	444,433,173	1,702,794	(432,996)
Western Wyoming	WYU	152,806,694	-	(45,586)	152,761,108	-	(45,586)	152,715,522	-	(45,586)
Total Distribution Plant		8,963,937,353	21,344,656	(5,084,550)	8,980,197,459	29,180,682	(5,084,550)	9,004,293,591	37,742,508	(5,084,550)

PacifiCorp
Oregon General Rate Case - December 2025
Pro Forma Plant Additions
and Retirements

Description	Factor	Adjusted EPIS Balance Dec 2023	Capital Additions	Retirements	Adjusted EPIS Balance Jan 2024	Capital Additions	Retirements	Adjusted EPIS Balance Feb 2024	Capital Additions	Retirements
General Plant:										
California	CA	23,389,892	8,929	(58,368)	23,340,453	7,494	(58,368)	23,289,579	11,197	(58,368)
Oregon	OR	236,238,564	198,818	(612,056)	235,825,327	169,071	(612,056)	235,382,343	236,302	(612,056)
Washington	WA	53,131,923	21,923	(108,683)	53,045,164	18,135	(108,683)	52,954,616	666,696	(108,683)
Eastern Wyoming	WYP	106,224,523	365,621	(183,824)	106,406,319	227,633	(183,824)	106,450,128	247,864	(183,824)
Utah	UT	296,835,653	1,561,023	(431,850)	297,964,827	608,500	(431,850)	298,141,477	733,555	(431,850)
Idaho	ID	59,132,717	272,646	(81,668)	59,323,695	135,632	(81,668)	59,377,659	154,033	(81,668)
Western Wyoming	WYU	20,679,853	-	(24,286)	20,655,567	-	(24,286)	20,631,281	-	(24,286)
Pre-merger Pacific	SG	637,020	-	(9,135)	627,884	-	(9,135)	618,749	-	(9,135)
Pre-merger Utah	SG	2,741,058	-	(27,040)	2,714,018	-	(27,040)	2,686,978	-	(27,040)
Post-merger	SG	330,908,763	22,814	(626,721)	330,304,856	22,814	(626,721)	329,700,949	22,814	(626,721)
General Office	SO	399,452,693	3,027,720	(1,386,364)	401,094,049	4,068,398	(1,386,364)	403,776,083	3,500,071	(1,386,364)
General Office	SG	-	-	-	-	-	-	-	-	-
General Office	SG	227,116	-	(67)	227,049	-	(67)	226,981	-	(67)
Customer Service	CN	15,104,628	-	(106,932)	14,997,696	-	(106,932)	14,890,764	-	(106,932)
Fuel Related	SE	3,282,950	-	(11,152)	3,271,799	-	(11,152)	3,260,647	-	(11,152)
Total General Plant		1,547,987,355	5,479,495	(3,668,146)	1,549,798,704	5,257,676	(3,668,146)	1,551,388,234	5,572,530	(3,668,146)
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	472,283	-	(10)	472,273	-	(10)	472,264	-	(10)
Customer Service	CN	231,117,829	-	(137,002)	230,980,828	-	(137,002)	230,843,826	-	(137,002)
Pre-merger Utah	SG	465,257	-	(2,057)	463,200	-	(2,057)	461,143	-	(2,057)
Pre-merger Pacific	SG	-	-	-	-	-	-	-	-	-
Idaho	ID	4,356,418	-	(29)	4,356,389	-	(29)	4,356,361	-	(29)
Oregon	OR	4,611,237	-	(402)	4,610,834	-	(402)	4,610,432	-	(402)
Fuel Related	SE	7,640	-	(244)	7,396	-	(244)	7,152	-	(244)
Post-merger	SG	207,601,243	-	(50,641)	207,550,602	-	(50,641)	207,499,961	-	(50,641)
Klamath Hydro Relicensing	SG-P	-	-	-	-	-	-	-	-	-
Hydro Relicensing	SG-P	103,427,081	-	(4,666)	103,422,416	-	(4,666)	103,417,750	-	(4,666)
Hydro Relicensing	SG-U	9,934,694	-	(14,920)	9,919,774	-	(14,920)	9,904,853	-	(14,920)
General Office	SO	499,085,143	83,543	(641,843)	498,526,843	511,666	(641,843)	498,396,666	4,115,427	(641,843)
Utah	UT	7,523,855	-	(301)	7,523,554	-	(301)	7,523,252	-	(301)
Washington	WA	2,021,868	-	-	2,021,868	-	-	2,021,868	-	-
Eastern Wyoming	WYP	5,334,087	-	(2,628)	5,331,459	-	(2,628)	5,328,831	-	(2,628)
Western Wyoming	WYU	-	-	-	-	-	-	-	-	-
Total Intangible Plant		1,075,958,636	83,543	(854,742)	1,075,187,436	511,666	(854,742)	1,074,844,360	4,115,427	(854,742)
Total		33,410,119,226	40,207,209	(17,457,665)	33,432,868,770	98,286,189	(17,457,665)	33,513,697,294	109,675,482	(17,457,665)

PacifiCorp
Oregon General Rate Case - December 2025
Pro Forma Plant Additions
and Retirements

Description	Factor	Adjusted EPIS Balance Mar 2024	Capital Additions	Retirements	Adjusted EPIS Balance Apr 2024	Capital Additions	Retirements	Adjusted EPIS Balance May 2024	Capital Additions	Retirements
Steam Production Plant:										
Pre-merger Pacific	SG	1,006,196,172	-	(278,562)	1,005,917,611	-	(278,562)	1,005,639,049	-	(278,562)
Pre-merger Utah	SG	1,049,556,262	-	(244,912)	1,049,311,350	-	(244,912)	1,049,066,438	-	(244,912)
Post-merger	SG	4,985,635,007	59,642,431	(3,316,963)	5,041,960,475	1,730,855	(3,316,963)	5,040,374,367	7,295,106	(3,316,963)
Geothermal - Blundell	SG	30,138,275	13,354	-	30,151,629	13,354	-	30,164,983	116,434	-
Pollution Control Equipment	SG	801,998	-	-	801,998	-	-	801,998	135,306	-
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-
Post-merger - Cholla	SG	1,266,851	-	-	1,266,851	-	-	1,266,851	-	-
Total Steam Plant		7,073,594,566	59,655,786	(3,840,437)	7,129,409,915	1,744,209	(3,840,437)	7,127,313,687	7,546,847	(3,840,437)
Hydro Production Plant:										
Pre-merger Pacific	SG	183,368,223	-	(39,742)	183,328,481	-	(39,742)	183,288,739	-	(39,742)
Pre-merger Utah	SG	39,297,447	-	(33,680)	39,263,767	-	(33,680)	39,230,087	-	(33,680)
Post-merger	SG-P	741,017,814	(63,998)	(233,011)	740,720,805	(63,998)	(233,011)	740,423,796	41,384	(233,011)
Post-merger	SG-U	170,723,630	(81,640)	(50,023)	170,591,967	309,046	(50,023)	170,850,990	2,738,481	(50,023)
Klamath	SG-P	1,412,738	-	-	1,412,738	-	-	1,412,738	-	-
Total Hydro Plant		1,135,819,852	(145,638)	(356,456)	1,135,317,758	245,048	(356,456)	1,135,206,350	2,779,865	(356,456)
Other Production Plant:										
Pre-merger Utah	SG	235,129	-	-	235,129	-	-	235,129	-	-
Post-merger	SG	1,971,224,381	(58,683)	(1,912,485)	1,969,253,212	788,469	(1,912,485)	1,968,129,196	2,175,783	(1,912,485)
Post-merger Wind	SG-W	3,322,296,762	1,176,443	(45,518)	3,323,427,687	1,059,776	(45,518)	3,324,441,946	4,240,544	(45,518)
Black Cap Solar	OR	866,233	-	-	866,233	-	-	866,233	-	-
Post-merger	SG	88,664,167	4,528	(66,123)	88,602,572	69,976	(66,123)	88,606,426	41,462	(66,123)
Total Other Plant		5,383,286,673	1,122,287	(2,024,126)	5,382,384,835	1,918,220	(2,024,126)	5,382,278,930	6,457,789	(2,024,126)
Transmission Plant:										
Pre-merger Pacific	SG	472,961,269	-	(188,188)	472,773,081	-	(188,188)	472,584,892	-	(188,188)
Pre-merger Utah	SG	608,369,784	-	(348,507)	608,021,278	-	(348,507)	607,672,771	-	(348,507)
Post-merger	SG	7,261,710,853	19,854,677	(1,092,514)	7,280,473,015	143,775,930	(1,092,514)	7,423,156,431	32,113,321	(1,092,514)
Total Transmission Plant		8,343,041,906	19,854,677	(1,629,209)	8,361,267,374	143,775,930	(1,629,209)	8,503,414,094	32,113,321	(1,629,209)
Distribution Plant:										
California	CA	439,894,188	987,459	(210,964)	440,670,683	4,566,999	(210,964)	445,026,717	5,228,942	(210,964)
Oregon	OR	2,655,461,431	6,244,403	(1,899,184)	2,659,806,651	7,680,228	(1,899,184)	2,665,587,695	8,383,127	(1,899,184)
Washington	WA	637,156,065	1,890,120	(223,044)	638,823,141	2,713,278	(223,044)	641,313,375	1,590,522	(223,044)
Eastern Wyoming	WYP	754,037,026	1,754,406	(291,286)	755,500,145	1,780,986	(291,286)	756,989,845	2,154,597	(291,286)
Utah	UT	3,952,029,930	22,482,828	(1,981,491)	3,972,531,268	39,781,916	(1,981,491)	4,010,331,693	24,502,818	(1,981,491)
Idaho	ID	445,702,972	1,725,621	(432,996)	446,995,597	11,818,626	(432,996)	458,381,228	1,795,936	(432,996)
Western Wyoming	WYU	152,669,936	-	(45,586)	152,624,351	-	(45,586)	152,578,765	-	(45,586)
Total Distribution Plant		9,036,951,549	35,084,837	(5,084,550)	9,066,951,836	68,342,033	(5,084,550)	9,130,209,319	43,655,942	(5,084,550)

PacifiCorp
Oregon General Rate Case - December 2025
Pro Forma Plant Additions
and Retirements

Description	Factor	Adjusted EPIS Balance Mar 2024	Capital Additions	Retirements	Adjusted EPIS Balance Apr 2024	Capital Additions	Retirements	Adjusted EPIS Balance May 2024	Capital Additions	Retirements
General Plant:										
California	CA	23,242,408	6,655	(58,368)	23,190,696	15,845	(58,368)	23,148,172	22,028	(58,368)
Oregon	OR	235,006,588	212,818	(612,056)	234,607,351	399,324	(612,056)	234,394,619	566,012	(612,056)
Washington	WA	53,512,630	12,645	(108,683)	53,416,592	35,212	(108,683)	53,343,122	108,629	(108,683)
Eastern Wyoming	WYP	106,514,168	245,983	(183,824)	106,576,326	298,998	(183,824)	106,691,500	371,656	(183,824)
Utah	UT	298,443,182	729,923	(431,850)	298,741,255	1,090,099	(431,850)	299,399,504	1,569,935	(431,850)
Idaho	ID	59,450,023	152,848	(81,668)	59,521,203	204,282	(81,668)	59,643,817	274,061	(81,668)
Western Wyoming	WYU	20,606,994	-	(24,286)	20,582,708	-	(24,286)	20,558,422	-	(24,286)
Pre-merger Pacific	SG	609,614	-	(9,135)	600,478	-	(9,135)	591,343	-	(9,135)
Pre-merger Utah	SG	2,659,938	-	(27,040)	2,632,898	-	(27,040)	2,605,858	-	(27,040)
Post-merger	SG	329,097,043	22,814	(626,721)	328,493,136	22,814	(626,721)	327,889,229	22,814	(626,721)
General Office	SO	405,889,790	3,083,380	(1,386,364)	407,586,807	4,246,871	(1,386,364)	410,447,313	7,324,335	(1,386,364)
General Office	SG	-	-	-	-	-	-	-	-	-
General Office	SG	226,914	-	(67)	226,847	-	(67)	226,779	-	(67)
Customer Service	CN	14,783,832	-	(106,932)	14,676,900	-	(106,932)	14,569,968	-	(106,932)
Fuel Related	SE	3,249,495	-	(11,152)	3,238,343	-	(11,152)	3,227,191	-	(11,152)
Total General Plant		1,553,292,619	4,467,066	(3,668,146)	1,554,091,540	6,313,444	(3,668,146)	1,556,736,838	10,259,469	(3,668,146)
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	472,254	-	(10)	472,244	-	(10)	472,235	-	(10)
Customer Service	CN	230,706,825	-	(137,002)	230,569,823	-	(137,002)	230,432,822	-	(137,002)
Pre-merger Utah	SG	459,087	-	(2,057)	457,030	-	(2,057)	454,974	-	(2,057)
Pre-merger Pacific	SG	-	-	-	-	-	-	-	-	-
Idaho	ID	4,356,332	-	(29)	4,356,303	-	(29)	4,356,274	-	(29)
Oregon	OR	4,610,029	-	(402)	4,609,627	-	(402)	4,609,224	-	(402)
Fuel Related	SE	6,908	-	(244)	6,664	-	(244)	6,419	-	(244)
Post-merger	SG	207,449,320	-	(50,641)	207,398,679	-	(50,641)	207,348,038	-	(50,641)
Klamath Hydro Relicensing	SG-P	-	-	-	-	-	-	-	-	-
Hydro Relicensing	SG-P	103,413,085	-	(4,666)	103,408,419	-	(4,666)	103,403,753	-	(4,666)
Hydro Relicensing	SG-U	9,889,933	-	(14,920)	9,875,013	-	(14,920)	9,860,092	-	(14,920)
General Office	SO	501,870,250	6,726,436	(641,843)	507,954,844	945,906	(641,843)	508,258,907	22,414,448	(641,843)
Utah	UT	7,522,951	-	(301)	7,522,649	-	(301)	7,522,348	-	(301)
Washington	WA	2,021,868	-	-	2,021,868	-	-	2,021,868	-	-
Eastern Wyoming	WYP	5,326,204	-	(2,628)	5,323,576	-	(2,628)	5,320,948	-	(2,628)
Western Wyoming	WYU	-	-	-	-	-	-	-	-	-
Total Intangible Plant		1,078,105,045	6,726,436	(854,742)	1,083,976,739	945,906	(854,742)	1,084,067,902	22,414,448	(854,742)
Total		33,605,915,110	126,765,451	(17,457,665)	33,715,222,896	223,284,790	(17,457,665)	33,921,050,021	125,227,681	(17,457,665)

PacifiCorp
Oregon General Rate Case - December 2025
Pro Forma Plant Additions
and Retirements

Description	Factor	Adjusted EPIS Balance Jun 2024	Capital Additions	Retirements	Adjusted EPIS Balance Jul 2024	Capital Additions	Retirements	Adjusted EPIS Balance Aug 2024	Capital Additions	Retirements
Steam Production Plant:										
Pre-merger Pacific	SG	1,005,360,487	-	(278,562)	1,005,081,926	-	(278,562)	1,004,803,364	-	(278,562)
Pre-merger Utah	SG	1,048,821,527	-	(244,912)	1,048,576,615	-	(244,912)	1,048,331,704	-	(244,912)
Post-merger	SG	5,044,352,510	1,558,544	(3,316,963)	5,042,594,090	2,565,716	(3,316,963)	5,041,842,842	956,209	(3,316,963)
Geothermal - Blundell	SG	30,281,417	13,354	-	30,294,772	13,354	-	30,308,126	13,354	-
Pollution Control Equipment	SG	937,305	330,484	-	1,267,789	-	-	1,267,789	-	-
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-
Post-merger - Cholla	SG	1,266,851	-	-	1,266,851	-	-	1,266,851	-	-
Total Steam Plant		7,131,020,097	1,902,382	(3,840,437)	7,129,082,043	2,579,070	(3,840,437)	7,127,820,676	969,563	(3,840,437)
Hydro Production Plant:										
Pre-merger Pacific	SG	183,248,998	-	(39,742)	183,209,256	-	(39,742)	183,169,514	-	(39,742)
Pre-merger Utah	SG	39,196,406	-	(33,680)	39,162,726	-	(33,680)	39,129,046	-	(33,680)
Post-merger	SG-P	740,232,169	669,755	(233,011)	740,668,914	(63,998)	(233,011)	740,371,905	11,947,356	(233,011)
Post-merger	SG-U	173,539,447	2,321,502	(50,023)	175,810,926	(81,640)	(50,023)	175,679,262	(81,640)	(50,023)
Klamath	SG-P	1,412,738	-	-	1,412,738	-	-	1,412,738	-	-
Total Hydro Plant		1,137,629,759	2,991,257	(356,456)	1,140,264,560	(145,638)	(356,456)	1,139,762,465	11,865,716	(356,456)
Other Production Plant:										
Pre-merger Utah	SG	235,129	-	-	235,129	-	-	235,129	-	-
Post-merger	SG	1,968,392,493	(58,683)	(1,912,485)	1,966,421,324	(58,683)	(1,912,485)	1,964,450,155	(58,683)	(1,912,485)
Post-merger Wind	SG-W	3,328,636,972	743,243	(45,518)	3,329,334,698	733,243	(45,518)	3,330,022,423	3,664,094	(45,518)
Black Cap Solar	OR	866,233	-	-	866,233	-	-	866,233	-	-
Post-merger	SG	88,581,765	192,559	(66,123)	88,708,201	4,528	(66,123)	88,646,607	4,528	(66,123)
Total Other Plant		5,386,712,593	877,118	(2,024,126)	5,385,565,585	679,087	(2,024,126)	5,384,220,547	3,609,939	(2,024,126)
Transmission Plant:										
Pre-merger Pacific	SG	472,396,704	-	(188,188)	472,208,516	-	(188,188)	472,020,328	-	(188,188)
Pre-merger Utah	SG	607,324,265	-	(348,507)	606,975,758	-	(348,507)	606,627,252	-	(348,507)
Post-merger	SG	7,454,177,238	70,618,841	(1,092,514)	7,523,703,565	70,521,761	(1,092,514)	7,593,132,811	185,450,001	(1,092,514)
Total Transmission Plant		8,533,898,207	70,618,841	(1,629,209)	8,602,887,839	70,521,761	(1,629,209)	8,671,780,391	185,450,001	(1,629,209)
Distribution Plant:										
California	CA	450,044,695	4,116,377	(210,964)	453,950,107	737,317	(210,964)	454,476,459	593,747	(210,964)
Oregon	OR	2,672,071,638	11,869,543	(1,899,184)	2,682,041,997	6,528,776	(1,899,184)	2,686,671,589	4,900,034	(1,899,184)
Washington	WA	642,680,854	2,031,635	(223,044)	644,489,445	1,649,037	(223,044)	645,915,438	1,050,309	(223,044)
Eastern Wyoming	WYP	758,853,156	1,840,137	(291,286)	760,402,007	2,065,668	(291,286)	762,176,389	2,042,315	(291,286)
Utah	UT	4,032,853,021	22,299,113	(1,981,491)	4,053,170,643	25,807,414	(1,981,491)	4,076,996,567	41,543,386	(1,981,491)
Idaho	ID	459,744,168	1,646,412	(432,996)	460,957,584	1,861,787	(432,996)	462,386,376	4,064,653	(432,996)
Western Wyoming	WYU	152,533,179	-	(45,586)	152,487,593	-	(45,586)	152,442,007	-	(45,586)
Total Distribution Plant		9,168,780,711	43,803,216	(5,084,550)	9,207,499,377	38,649,999	(5,084,550)	9,241,064,826	54,194,443	(5,084,550)

PacifiCorp
Oregon General Rate Case - December 2025
Pro Forma Plant Additions
and Retirements

Description	Factor	Adjusted EPIS Balance Jun 2024	Capital Additions	Retirements	Adjusted EPIS Balance Jul 2024	Capital Additions	Retirements	Adjusted EPIS Balance Aug 2024	Capital Additions	Retirements
General Plant:										
California	CA	23,111,832	40,686	(58,368)	23,094,150	19,043	(58,368)	23,054,826	35,207	(58,368)
Oregon	OR	234,348,576	906,904	(612,056)	234,643,424	393,237	(612,056)	234,424,605	843,293	(612,056)
Washington	WA	53,343,068	95,228	(108,683)	53,329,613	34,565	(108,683)	53,255,496	85,203	(108,683)
Eastern Wyoming	WYP	106,879,332	281,715	(183,824)	106,977,222	368,073	(183,824)	107,161,471	299,228	(183,824)
Utah	UT	300,537,590	966,870	(431,850)	301,072,611	1,563,651	(431,850)	302,204,411	1,089,261	(431,850)
Idaho	ID	59,836,209	187,202	(81,668)	59,941,743	272,888	(81,668)	60,132,963	205,597	(81,668)
Western Wyoming	WYU	20,534,136	-	(24,286)	20,509,850	-	(24,286)	20,485,563	-	(24,286)
Pre-merger Pacific	SG	582,207	-	(9,135)	573,072	-	(9,135)	563,936	-	(9,135)
Pre-merger Utah	SG	2,578,818	-	(27,040)	2,551,777	-	(27,040)	2,524,737	-	(27,040)
Post-merger	SG	327,285,322	32,222	(626,721)	326,690,823	22,814	(626,721)	326,086,916	22,814	(626,721)
General Office	SO	416,385,285	4,073,953	(1,386,364)	419,072,874	3,342,439	(1,386,364)	421,028,949	3,581,066	(1,386,364)
General Office	SG	-	-	-	-	-	-	-	-	-
General Office	SG	226,712	-	(67)	226,645	-	(67)	226,577	-	(67)
Customer Service	CN	14,463,036	-	(106,932)	14,356,104	-	(106,932)	14,249,172	-	(106,932)
Fuel Related	SE	3,216,039	-	(11,152)	3,204,887	-	(11,152)	3,193,736	-	(11,152)
Total General Plant		1,563,328,161	6,584,780	(3,668,146)	1,566,244,796	6,016,709	(3,668,146)	1,568,593,359	6,161,669	(3,668,146)
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	472,225	-	(10)	472,215	-	(10)	472,206	-	(10)
Customer Service	CN	230,295,820	-	(137,002)	230,158,819	-	(137,002)	230,021,817	-	(137,002)
Pre-merger Utah	SG	452,917	-	(2,057)	450,860	-	(2,057)	448,804	-	(2,057)
Pre-merger Pacific	SG	-	-	-	-	-	-	-	-	-
Idaho	ID	4,356,246	-	(29)	4,356,217	-	(29)	4,356,188	-	(29)
Oregon	OR	4,608,822	-	(402)	4,608,419	-	(402)	4,608,017	-	(402)
Fuel Related	SE	6,175	-	(244)	5,931	-	(244)	5,687	-	(244)
Post-merger	SG	207,297,396	-	(50,641)	207,246,755	-	(50,641)	207,196,114	-	(50,641)
Klamath Hydro Relicensing	SG-P	-	-	-	-	-	-	-	-	-
Hydro Relicensing	SG-P	103,399,088	-	(4,666)	103,394,422	-	(4,666)	103,389,757	-	(4,666)
Hydro Relicensing	SG-U	9,845,172	-	(14,920)	9,830,251	-	(14,920)	9,815,331	-	(14,920)
General Office	SO	530,031,512	205,343	(641,843)	529,595,012	2,677,837	(641,843)	531,631,006	161,390,829	(641,843)
Utah	UT	7,522,046	-	(301)	7,521,745	-	(301)	7,521,443	-	(301)
Washington	WA	2,021,868	-	-	2,021,868	-	-	2,021,868	-	-
Eastern Wyoming	WYP	5,318,321	-	(2,628)	5,315,693	-	(2,628)	5,313,065	-	(2,628)
Western Wyoming	WYU	-	-	-	-	-	-	-	-	-
Total Intangible Plant		1,105,627,608	205,343	(854,742)	1,104,978,208	2,677,837	(854,742)	1,106,801,302	161,390,829	(854,742)
Total		34,028,820,036	126,982,937	(17,457,665)	34,138,345,308	120,978,824	(17,457,665)	34,241,866,466	423,642,159	(17,457,665)

PacifiCorp
Oregon General Rate Case - December 2025
Pro Forma Plant Additions
and Retirements

Description	Factor	Adjusted EPIS Balance Sep 2024	Capital Additions	Retirements	Adjusted EPIS Balance Oct 2024	Capital Additions	Retirements	Adjusted EPIS Balance Nov 2024	Capital Additions	Retirements
Steam Production Plant:										
Pre-merger Pacific	SG	1,004,524,803	-	(278,562)	1,004,246,241	-	(278,562)	1,003,967,679	-	(278,562)
Pre-merger Utah	SG	1,048,086,792	-	(244,912)	1,047,841,880	-	(244,912)	1,047,596,969	-	(244,912)
Post-merger	SG	5,039,482,088	1,518,092	(3,316,963)	5,037,683,216	2,706,515	(3,316,963)	5,037,072,768	14,465,917	(3,316,963)
Geothermal - Blundell	SG	30,321,480	13,354	-	30,334,834	13,354	-	30,348,188	13,354	-
Pollution Control Equipment	SG	1,267,789	-	-	1,267,789	-	-	1,267,789	68,738	-
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-
Pollution Control Equipment	SG	-	-	-	-	-	-	-	-	-
Post-merger - Cholla	SG	1,266,851	-	-	1,266,851	-	-	1,266,851	-	-
Total Steam Plant		7,124,949,802	1,531,446	(3,840,437)	7,122,640,811	2,719,869	(3,840,437)	7,121,520,244	14,548,009	(3,840,437)
Hydro Production Plant:										
Pre-merger Pacific	SG	183,129,773	-	(39,742)	183,090,031	-	(39,742)	183,050,289	-	(39,742)
Pre-merger Utah	SG	39,095,365	-	(33,680)	39,061,685	-	(33,680)	39,028,005	-	(33,680)
Post-merger	SG-P	752,086,250	15,567,767	(233,011)	767,421,006	3,317,035	(233,011)	770,505,030	7,205,580	(233,011)
Post-merger	SG-U	175,547,599	(81,640)	(50,023)	175,415,936	13,616,005	(50,023)	188,981,917	7,235,247	(50,023)
Klamath	SG-P	1,412,738	-	-	1,412,738	-	-	1,412,738	-	-
Total Hydro Plant		1,151,271,725	15,486,127	(356,456)	1,166,401,396	16,933,040	(356,456)	1,182,977,980	14,440,827	(356,456)
Other Production Plant:										
Pre-merger Utah	SG	235,129	-	-	235,129	-	-	235,129	-	-
Post-merger	SG	1,962,478,986	(58,683)	(1,912,485)	1,960,507,818	(58,683)	(1,912,485)	1,958,536,649	1,912,799	(1,912,485)
Post-merger Wind	SG-W	3,333,640,999	794,780	(45,518)	3,334,390,262	794,780	(45,518)	3,335,139,525	5,012,496	(45,518)
Black Cap Solar	OR	866,233	-	-	866,233	-	-	866,233	99,127	-
Post-merger	SG	88,585,012	4,528	(66,123)	88,523,417	4,528	(66,123)	88,461,823	4,528	(66,123)
Total Other Plant		5,385,806,360	740,625	(2,024,126)	5,384,522,860	740,625	(2,024,126)	5,383,239,359	7,028,950	(2,024,126)
Transmission Plant:										
Pre-merger Pacific	SG	471,832,140	-	(188,188)	471,643,951	-	(188,188)	471,455,763	-	(188,188)
Pre-merger Utah	SG	606,278,745	-	(348,507)	605,930,239	-	(348,507)	605,581,732	-	(348,507)
Post-merger	SG	7,777,490,298	54,536,055	(1,092,514)	7,830,933,838	2,318,688,582	(1,092,514)	10,148,529,906	34,729,797	(1,092,514)
Total Transmission Plant		8,855,601,183	54,536,055	(1,629,209)	8,908,508,028	2,318,688,582	(1,629,209)	11,225,567,402	34,729,797	(1,629,209)
Distribution Plant:										
California	CA	454,859,241	1,751,266	(210,964)	456,399,543	1,477,399	(210,964)	457,665,978	118,896,786	(210,964)
Oregon	OR	2,689,672,439	3,757,193	(1,899,184)	2,691,530,449	12,879,160	(1,899,184)	2,702,510,425	4,877,810	(1,899,184)
Washington	WA	646,742,704	878,112	(223,044)	647,397,772	3,489,081	(223,044)	650,663,810	12,121,013	(223,044)
Eastern Wyoming	WYP	763,927,418	1,670,383	(291,286)	765,306,515	1,558,225	(291,286)	766,573,453	9,389,036	(291,286)
Utah	UT	4,116,558,461	18,685,762	(1,981,491)	4,133,262,733	25,480,692	(1,981,491)	4,156,761,934	51,285,315	(1,981,491)
Idaho	ID	466,018,034	1,626,659	(432,996)	467,211,697	1,518,833	(432,996)	468,297,534	1,475,347	(432,996)
Western Wyoming	WYU	152,396,421	-	(45,586)	152,350,836	-	(45,586)	152,305,250	-	(45,586)
Total Distribution Plant		9,290,174,718	28,369,376	(5,084,550)	9,313,459,544	46,403,390	(5,084,550)	9,354,778,384	198,045,307	(5,084,550)

PacifiCorp
Oregon General Rate Case - December 2025
Pro Forma Plant Additions
and Retirements

Description	Factor	Adjusted EPIS Balance Sep 2024	Capital Additions	Retirements	Adjusted EPIS Balance Oct 2024	Capital Additions	Retirements	Adjusted EPIS Balance Nov 2024	Capital Additions	Retirements
General Plant:										
California	CA	23,031,665	47,168	(58,368)	23,020,466	28,224	(58,368)	22,990,322	1,469,444	(58,368)
Oregon	OR	234,655,843	1,103,527	(612,056)	235,147,315	629,987	(612,056)	235,165,247	51,551,224	(612,056)
Washington	WA	53,232,017	109,051	(108,683)	53,232,385	59,800	(108,683)	53,183,503	2,948,377	(108,683)
Eastern Wyoming	WYP	107,276,875	366,546	(183,824)	107,459,596	1,279,234	(183,824)	108,555,005	1,531,669	(183,824)
Utah	UT	302,861,822	1,561,838	(431,850)	303,991,811	2,155,682	(431,850)	305,715,643	2,752,663	(431,850)
Idaho	ID	60,256,891	272,921	(81,668)	60,448,144	358,595	(81,668)	60,725,071	445,494	(81,668)
Western Wyoming	WYU	20,461,277	-	(24,286)	20,436,991	-	(24,286)	20,412,705	-	(24,286)
Pre-merger Pacific	SG	554,801	-	(9,135)	545,666	-	(9,135)	536,530	-	(9,135)
Pre-merger Utah	SG	2,497,697	-	(27,040)	2,470,657	-	(27,040)	2,443,617	-	(27,040)
Post-merger	SG	325,483,009	22,814	(626,721)	324,879,102	75,888	(626,721)	324,328,269	27,639	(626,721)
General Office	SO	423,223,651	4,103,171	(1,386,364)	425,940,458	3,175,568	(1,386,364)	427,729,662	21,628,151	(1,386,364)
General Office	SG	-	-	-	-	-	-	-	-	-
General Office	SG	226,510	-	(67)	226,443	-	(67)	226,375	-	(67)
Customer Service	CN	14,142,240	-	(106,932)	14,035,308	-	(106,932)	13,928,376	-	(106,932)
Fuel Related	SE	3,182,584	-	(11,152)	3,171,432	-	(11,152)	3,160,280	-	(11,152)
Total General Plant		1,571,086,883	7,587,035	(3,668,146)	1,575,005,772	7,762,978	(3,668,146)	1,579,100,605	82,354,662	(3,668,146)
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	472,196	-	(10)	472,186	-	(10)	472,177	-	(10)
Customer Service	CN	229,884,816	-	(137,002)	229,747,814	-	(137,002)	229,610,812	-	(137,002)
Pre-merger Utah	SG	446,747	-	(2,057)	444,691	-	(2,057)	442,634	-	(2,057)
Pre-merger Pacific	SG	-	-	-	-	-	-	-	-	-
Idaho	ID	4,356,159	-	(29)	4,356,130	-	(29)	4,356,102	-	(29)
Oregon	OR	4,607,614	-	(402)	4,607,212	-	(402)	4,606,809	-	(402)
Fuel Related	SE	5,442	-	(244)	5,198	-	(244)	4,954	-	(244)
Post-merger	SG	207,145,473	-	(50,641)	207,094,832	-	(50,641)	207,044,191	-	(50,641)
Klamath Hydro Relicensing	SG-P	-	-	-	-	-	-	-	-	-
Hydro Relicensing	SG-P	103,385,091	-	(4,666)	103,380,425	-	(4,666)	103,375,760	-	(4,666)
Hydro Relicensing	SG-U	9,800,410	-	(14,920)	9,785,490	-	(14,920)	9,770,570	-	(14,920)
General Office	SO	692,379,992	205,343	(641,843)	691,943,492	1,576,837	(641,843)	692,878,486	8,838,107	(641,843)
Utah	UT	7,521,142	-	(301)	7,520,840	-	(301)	7,520,539	-	(301)
Washington	WA	2,021,868	-	-	2,021,868	-	-	2,021,868	-	-
Eastern Wyoming	WYP	5,310,438	-	(2,628)	5,307,810	-	(2,628)	5,305,182	-	(2,628)
Western Wyoming	WYU	-	-	-	-	-	-	-	-	-
Total Intangible Plant		1,267,337,389	205,343	(854,742)	1,266,687,989	1,576,837	(854,742)	1,267,410,084	8,838,107	(854,742)
Total		34,648,050,960	108,456,006	(17,457,665)	34,739,049,301	2,394,825,321	(17,457,665)	37,116,416,957	359,985,657	(17,457,665)

PacifiCorp
Oregon General Rate Case - December 2025
Pro Forma Plant Additions
and Retirements

Description	Factor	Adjusted EPIS Balance Dec 2024	End of Period December 2024 Test Period Balance
Steam Production Plant:			
Pre-merger Pacific	SG	1,003,689,118	1,003,689,118
Pre-merger Utah	SG	1,047,352,057	1,047,352,057
Post-merger	SG	5,048,221,722	5,048,221,722
Geothermal - Blundell	SG	30,361,542	30,361,542
Pollution Control Equipment	SG	1,336,526	1,336,526
Pollution Control Equipment	SG	-	-
Pollution Control Equipment	SG	-	-
Post-merger - Cholla	SG	1,266,851	1,266,851
Total Steam Plant		7,132,227,816	7,132,227,816
Hydro Production Plant:			
Pre-merger Pacific	SG	183,010,548	183,010,548
Pre-merger Utah	SG	38,994,324	38,994,324
Post-merger	SG-P	777,477,600	777,477,600
Post-merger	SG-U	196,167,141	196,167,141
Klamath	SG-P	1,412,738	1,412,738
Total Hydro Plant		1,197,062,350	1,197,062,350
Other Production Plant:			
Pre-merger Utah	SG	235,129	235,129
Post-merger	SG	1,958,536,962	1,958,536,962
Post-merger Wind	SG-W	3,340,106,504	3,340,106,504
Black Cap Solar	OR	965,360	965,360
Post-merger	SG	88,400,228	88,400,228
Total Other Plant		5,388,244,183	5,388,244,183
Transmission Plant:			
Pre-merger Pacific	SG	471,267,575	471,267,575
Pre-merger Utah	SG	605,233,226	605,233,226
Post-merger	SG	10,182,167,188	10,182,167,188
Total Transmission Plant		11,258,667,989	11,258,667,989
Distribution Plant:			
California	CA	576,351,800	576,351,800
Oregon	OR	2,705,489,051	2,705,489,051
Washington	WA	662,561,779	662,561,779
Eastern Wyoming	WYP	775,671,204	775,671,204
Utah	UT	4,206,065,758	4,206,065,758
Idaho	ID	469,339,885	469,339,885
Western Wyoming	WYU	152,259,664	152,259,664
Total Distribution Plant		9,547,739,141	9,547,739,141

PacifiCorp
Oregon General Rate Case - December 2025
Pro Forma Plant Additions
and Retirements

Description	Factor	Adjusted EPIS Balance Dec 2024	End of Period December 2024 Test Period Balance
General Plant:			
California	CA	24,401,398	24,401,398
Oregon	OR	286,104,415	286,104,415
Washington	WA	56,023,197	56,023,197
Eastern Wyoming	WYP	109,902,851	109,902,851
Utah	UT	308,036,456	308,036,456
Idaho	ID	61,088,897	61,088,897
Western Wyoming	WYU	20,388,418	20,388,418
Pre-merger Pacific	SG	527,395	527,395
Pre-merger Utah	SG	2,416,577	2,416,577
Post-merger	SG	323,729,187	323,729,187
General Office	SO	447,971,449	447,971,449
General Office	SG	-	-
General Office	SG	226,308	226,308
Customer Service	CN	13,821,444	13,821,444
Fuel Related	SE	3,149,128	3,149,128
Total General Plant		1,657,787,121	1,657,787,121
Mining Plant:			
Coal Mine	SE	1,822,901	1,822,901
Total Mining Plant		1,822,901	1,822,901
Intangible Plant:			
California	CA	472,167	472,167
Customer Service	CN	229,473,811	229,473,811
Pre-merger Utah	SG	440,577	440,577
Pre-merger Pacific	SG	-	-
Idaho	ID	4,356,073	4,356,073
Oregon	OR	4,606,407	4,606,407
Fuel Related	SE	4,710	4,710
Post-merger	SG	206,993,550	206,993,550
Klamath Hydro Relicensing	SG-P	-	-
Hydro Relicensing	SG-P	103,371,094	103,371,094
Hydro Relicensing	SG-U	9,755,649	9,755,649
General Office	SO	701,074,750	701,074,750
Utah	UT	7,520,237	7,520,237
Washington	WA	2,021,868	2,021,868
Eastern Wyoming	WYP	5,302,554	5,302,554
Western Wyoming	WYU	-	-
Total Intangible Plant		1,275,393,448	1,275,393,448
Total		37,458,944,949	**37,458,944,949**
			Ref 8.4.4

PacifiCorp
Oregon General Rate Case - December 2025
Pro Forma Plant Additions and Retirements
Steam Plant Additions

Project Description	FERC Account	Factor	Inservice Date	July23 to Dec24 Plant Adds	Ref.
Jim Bridger - CCR Jim Bridger FGD Pond 3	312	SG	Sep-23	41,278,919	8.4.30
Jim Bridger - U1 Conversion to Natural Gas Imp. Phase	312	SG	Apr-24	17,307,777	8.4.30
Jim Bridger - U2 Conversion to Natural Gas Imp Phase	312	SG	Apr-24	17,267,132	8.4.30
Naughton - U2 Hydrogen Damage Tube Replacement CY23	312	SG	Aug-23	3,561,453	
Hunter - 303 Boiler WW Panels and Coating	312	SG	Apr-24	2,893,495	
Hunter - 303 LP Turbine Overhaul	312	SG	Apr-24	2,731,124	
Hunter - 303 Boiler Rear Lower Slope Replacement	312	SG	Apr-24	2,632,457	
Huntington - U2 Boiler Reheat Header Replacement	312	SG	Mar-24	2,489,496	
Dave Johnston - U0 - MILL BLANKET - 2024	312	SG	Various	2,486,112	
Hunter - 303 Baghouse Bags - CY24	312	SG	Apr-24	2,361,574	
Dave Johnston - U0 - PUMPS AND VALVES - 2024	312	SG	Various	2,260,102	
Hunter - 303 Scrubber Component Overhaul	312	SG	Apr-24	1,948,353	
Hunter - 303 3-7 Feedwater Heater Replacement	312	SG	Dec-24	1,883,446	
Hunter - 303 Stack Inlet Duct Overhaul	312	SG	Apr-24	1,853,078	
Huntington - U2 Burner Corner Coal Nozzle & Tip repla	312	SG	Dec-23	1,632,279	
Hunter - 303 3-6 Feedwater Heater Replacement	312	SG	Apr-24	1,523,504	
Hunter - 300 Recovery Basin Lining	312	SG	Sep-23	1,509,435	
Hunter - 303 Burner Nozzle Overhaul	312	SG	Apr-24	1,405,294	
Dave Johnston - U0 PurchLargeCentrifCompressor	312	SG	Mar-24	1,319,082	
Colstrip - COLU4 Overhaul Capital CY24	312	SG	Dec-24	1,250,307	
Dave Johnston - U0 316(b) Compliance - Barrier Net Installation	312	SG	Dec-23	1,194,838	
Dave Johnston - U0 - PUMPS AND VALVES - 2023	312	SG	Various	1,166,899	
Jim Bridger - U0 Southend Building Heating 22/23/24	312	SG	Dec-24	1,121,567	
Wyodak - U1 - Pulverizer Overhaul "A" CY24	312	SG	Apr-24	1,040,496	
Projects Less Than $1million	312	SG	Various	78,506,612	
Steam Plant Five Year Average Removals	312	SG	Various	(11,941,505)	
				182,683,326	

PacifiCorp
Oregon General Rate Case - December 2025
Pro Forma Plant Additions and Retirements
Hydro Plant Additions

Project Description	FERC Account	Factor	Inservice Date	July23 to Dec24 Plant Adds	Ref.
IKL-Fall Creek Hatchery	332	SG-P	Mar-24	36,460,246	8.4.30
Hydro West Misc Projects <$100k	332	SG-P	Various	14,132,302	
ILR 4.5 Yale Downstream Fish Passage	332	SG-P	Oct-24	10,428,493	8.4.31
Cutler Relicensing	332	SG-U	Nov-24	8,446,875	
Swift 1 Spillway Gate Bulkhead	332	SG-P	Sep-24	6,153,991	
Toketee 2 Turbine Refurbishment	332	SG-P	Dec-23	5,741,655	
ILR 11.2.2.12 Beaver Bay PH 1 Renovation	332	SG-P	Dec-24	5,556,226	
Cutler Surge Tank Anchor Upgrades	332	SG-U	Dec-24	3,568,904	
Soda Spinning Reserve	332	SG-U	Dec-24	2,676,151	
Hydro Blanket / Emergent Capital	332	SG-P	Various	2,671,570	
Merwin Gantry Crane Coating	332	SG-P	Dec-23	2,623,640	
Ashton Trash Rake	332	SG-U	Jul-24	2,403,142	
Hydro East Misc Projects <$100k	332	SG-U	Various	1,937,700	
Paris Hydro Project Decommissioning	332	SG-U	Nov-24	1,894,402	
Oneida Switchgear	332	SG-U	Jun-24	1,842,656	
ILR 11.2.2.13 Cougar Park Renovation	332	SG-P	Dec-23	1,652,720	
Hydro Facilities & Office Equipment	332	SG-P	Various	1,516,499	
Grace Unit #5 Pivot Valve	332	SG-U	Nov-24	1,502,950	
Hydro Gen/Other Equipment Failure Emergent	332	SG-U	Various	1,448,676	
Iron Gate (Fall Creek Hatchery) Bridge	332	SG-P	Dec-24	1,412,738	
Grace Unit #4 Pivot Valve	332	SG-U	Nov-24	1,396,299	
ILR 11.2.2.12 Beaver Bay Park Redesign p	332	SG-P	Sep-23	1,363,794	
IRO P3 Auxiliary Minimum Flow Supply System	332	SG-P	Oct-24	1,355,811	
IWF Tailrace Realignment	332	SG-P	Dec-23	1,343,613	
ILR 11.2.14 ADA Fishing Access	332	SG-P	Sep-24	1,073,069	
Projects Less Than $1million	332	SG-P	Various	12,903,071	
Projects Less Than $1million	332	SG-U	Various	5,649,980	
Hydro Plant Five Year Average Removals	332	SG-P	Various	(1,640,766)	
Hydro Plant Five Year Average Removals	332	SG-U	Various	(1,469,517)	
				136,046,888	

PacifiCorp
Oregon General Rate Case - December 2025
Pro Forma Plant Additions and Retirements
Other Plant Additions

Project Description	FERC Account	Factor	Inservice Date	July23 to Dec24 Plant Adds	Ref.
Foote Creek 2-4 Repowering	343	SG-W	Nov-23	84,731,798	8.4.31
Lake Side - U21 Major Inspection Overhaul - CY23	343	SG	Oct-23	17,331,361	8.4.31
Lake Side - U22 Major Inspection Overhaul - CY23	343	SG	Oct-23	17,331,361	8.4.32
Dunlap 1 Wind Operating	343	SG-W	Various	9,362,966	
Wind Component Replacement Blanket	343	SG-W	Various	7,997,638	
Pryor Mountain Wind Operating	343	SG-W	Various	3,827,080	
Hermiston - HERMU1 Overhaul Capital CY23 HGP	343	SG	Dec-23	3,569,822	
W-1799 EAGLE MITIGATION	343	SG-W	Dec-24	1,743,279	
Wind SCADA Hardware/Software	343	SG-W	Various	1,560,000	
Hermiston - HERM Addl Capital Upgrades/Repl CY24	343	SG	Dec-24	1,464,323	
Cedar Springs Wind Operating	343	SG-W	Various	1,114,462	
Wind Electrical Components	343	SG-W	Various	1,000,000	
Projects Less Than $1million	343	SG	Various	11,227,660	
Projects Less Than $1million - Wind	343	SG-W	Various	4,434,932	
Projects Less Than $1million	343	SSGCT	Various	707,022	
Projects Less Than $1million	343	OR	Various	370,052	
Other Plant Five Year Average Removals	343	SG	Various	(2,460,627)	
Other Plant - Wind Five Year Average Removals	343	SG	Various	(292,108)	
				165,021,021	

PacifiCorp
Oregon General Rate Case - December 2025
Pro Forma Plant Additions and Retirements
Transmission Plant Additions

Project Description	FERC Account	Factor	Inservice Date	July23 to Dec24 Plant Adds	Ref.
Gateway South Aeolus Mona 500kV Line	355	SG	Dec-24	2,076,638,863	8.4.32
D1: Windstar - Shirley Basin 230kV Line	355	SG	Various	288,005,105	8.4.32
Anticline 345 kV Phase Shifter	355	SG	Nov-24	133,522,880	8.4.32
Oquirrh Terminal 345kV Line	355	SG	Nov-24	75,845,547	8.4.33
TMP Customer New Revenue East	355	SG	Various	71,823,863	
Project Specialized	355	SG	Various	63,544,108	8.4.33
Wildfire Mitigation - Trans	355	SG	Various	52,166,405	
TMP EV2024 Network Upgrades for Gen Interconnection	355	SG	Various	40,069,949	
Path C Transmission Improvements	355	SG	May-24	31,337,191	8.4.33
Customer 8 - UT - Trans (1)	355	SG	Various	25,300,000	8.4.33
Gateway South 230kV supporting projects	355	SG	Dec-24	20,213,000	8.4.34
Enhanced Substation Security	355	SG	Aug-24	18,000,000	8.4.34
Klamath Falls - Snow Goose 230kV Line No. 2 TPL	355	SG	Aug-23	15,580,243	8.4.34
Transmission - PP	355	SG	Various	12,100,908	
Fort Hall/BIA Goshen Kinport 2310(1185)	355	SG	Dec-23	11,789,976	8.4.34
Replacements Investment Programs - T - UT	355	SG	Various	10,033,135	
Walla Walla 69 kV Loop Reconfig Recondct	355	SG	Various	9,444,100	
Oregon Rplc OH Trans - Poles	355	SG	Various	9,350,920	
Oquirrh - Grinding Loop Reconductor	355	SG	May-24	9,314,629	
Customer 27 - UT - Trans	355	SG	Jun-24	8,605,007	
Houston Lake-Ponderosa Add Second 115kV Line	355	SG	May-24	7,943,819	
Replace Overhead Transmission Poles - UT	355	SG	Various	7,785,959	
Magna Cap and Tooele - Pine Cyn Rebuild 138kV	355	SG	Various	7,472,693	
Jackalope-Bixby Transmission Upgrade	355	SG	Oct-24	7,034,353	
Bear River 138kV Conversion	355	SG	Various	6,996,140	
Customer 22 - UT - Trans	355	SG	Sep-24	6,934,686	
OTP196 Nephi 2nd POD	355	SG	Sep-24	6,905,150	
Tucker 69 kV Tie Line	355	SG	Various	6,405,107	
Klamath Falls -Hornet 69 kv line 9, Reconductor 5.3 miles T	355	SG	Nov-23	6,029,448	
Replace Substation Switchgear, Breakers, Reclosers - T - UT	355	SG	Various	5,771,565	
Line 30 & 65 Convert to 115 kV; New 230-69kV Sub T	355	SG	Various	5,758,615	
Fort Hall/BIA Jim Bridger Kinport G-2067 - shared IPC	355	SG	Jun-24	5,372,570	
Replace - Storm & Casualty - Trans UT	355	SG	Various	5,261,024	
Midpoint 500 kV Series Capacitor Bank Replacement (IDP)	355	SG	Jan-24	4,911,459	
Replace Overhead Transmission Lines - Other - UT	355	SG	Various	4,816,528	
Lone Pine- Whetstone 230kV Line	355	SG	Various	4,439,814	
Midvalley: Rpl Failed #1 Transformer	355	SG	Various	4,177,244	
Grantsville Increase Capacity - Trans	355	SG	Dec-23	4,002,715	
Replace Sigurd #6 345-230kV 450 MVA XFMR	355	SG	Dec-23	4,000,000	
Apple Valley Install New Dist Sub - Trans	355	SG	Nov-23	3,866,009	
Cross Hollows Install 2nd Xfmr - Trans	355	SG	Mar-24	3,780,901	
Jim Bridger - Goshen 345kV Ln Str Replc	355	SG	Jul-24	3,600,000	
Huntington - U0 Universal Spare GSU Huntington Plant	355	SG	Dec-23	3,588,484	
St Johns (BPA) to Knott 115kV Line Conversion Project	355	SG	Various	3,342,248	
Oregon Rpl OH Trans Other	355	SG	Various	3,337,675	
Wildfire - Trans PP	355	SG	Various	3,333,472	
WP West Acquisitions-ACC Burial on 100S	355	SG	Mar-24	3,283,134	
Replacements Investment Programs - T - WY	355	SG	Various	3,191,759	
Montpelier Area Voltage Support	355	SG	Various	2,963,176	
Calif Rplc Trans Storm & Casualty	355	SG	Various	2,941,365	
SF6 - Circuit Breaker Replacements - T - UT	355	SG	Various	2,716,927	
Dillard Tap: 37-1 to Winston:37-5 69KV Trans Tie	355	SG	Oct-24	2,616,829	
Moab-Pinto 138 kV: Install Auto Rollover	355	SG	Apr-24	2,567,444	
Amps - Control Building Addition	355	SG	Apr-24	2,562,093	

PacifiCorp
Oregon General Rate Case - December 2025
Pro Forma Plant Additions and Retirements
Transmission Plant Additions

Project Description	FERC Account	Factor	Inservice Date	July23 to Dec24 Plant Adds	Ref.
Transmission System Hardening and Resiliency	355	SG	Various	2,419,211	
Oregon - Trans Highway Relocations	355	SG	Various	2,373,564	
Replacements Investment Programs - T - ID	355	SG	Various	2,321,554	
St. George-Purgatory Flat Line Upgrade	355	SG	Dec-23	2,313,670	
Midpoint T501 TFMR Damage (IDP)	355	SG	Jul-24	2,303,034	
OTP188 UAMPS Lehi 138kV Loop (Carter to Saratoga)	355	SG	May-24	2,117,456	
Pilot Butte Replace 3 Failed CTs	355	SG	Nov-23	2,096,469	
Upgrades Investment Programs - T - UT	355	SG	Various	2,076,865	
BLM & Other ROW Renewals - T - ID	355	SG	Various	2,071,625	
Populus - Terminal 345kV Line	355	SG	Jul-05	2,063,400	
Trans Customer System Upgrade- East >$1.0M	355	SG	Various	2,045,184	
TMP Customer New Revenue West	355	SG	Various	1,973,360	
Replace Overhead Transmission Lines - Other - ID	355	SG	Various	1,760,881	
Oregon Rplc Trans Storm & Casualty	355	SG	Various	1,735,713	
Hunter - 301 Spare Main GSU Replacement	355	SG	Apr-23	1,689,538	
Transmission Reliability Improvements - UT	355	SG	Various	1,685,371	
Mandated Investment Programs - T - UT	355	SG	Various	1,682,527	
Transmission - PP - New Rev	355	SG	Various	1,436,833	
PP Transmission >$1.0M	355	SG	Various	1,387,438	
Butlerville Complete 138 kV Ring Bus and HMI	355	SG	Jun-24	1,377,176	
Replace Overhead Transmission Lines - Other - WY	355	SG	Various	1,372,451	
Replace Overhead Transmission Poles - ID	355	SG	Various	1,349,566	
Downtown 8kV System Upgrade - Trans	355	SG	Various	1,345,500	
Aeolus-Bridger/Anticline 500 kV Line (GW) Total	355	SG	Nov-20	1,322,431	
Cherry Lane - Warm Springs 69kV Reconductor - T	355	SG	Sep-23	1,258,200	
Replace - Storm & Casualty - Trans ID	355	SG	Various	1,210,456	
Prospect Point Transformer High-Side Fuse Replacement	355	SG	Apr-24	1,183,079	
Replace Substation Bushings, Glass & Other - T - UT	355	SG	Various	1,134,365	
Replace Substation Transformers - T - UT	355	SG	Various	1,072,066	
Meridian RAS Expansion	355	SG	May-24	1,048,534	
Replace Overhead Transmission Poles - WY	355	SG	Various	1,012,175	
Projects Less Than $1million	355	SG	Various	15,588,608	
Transmission Plant Five Year Average Removals	355	SG	Various	(10,684,574)	
				3,199,539,960	

PacifiCorp
Oregon General Rate Case - December 2025
Pro Forma Plant Additions and Retirements
Distribution Plant Additions

Project Description	FERC Account	Factor	Inservice Date	July23 to Dec24 Plant Adds	Ref.
Wildfire Mitigation Plan - CA D	360-373	CA	Various	168,204,243	
Wildfire Mitigation - Dist - UT	360-373	UT	Various	87,718,571	
Utah-New Connect - Residential	360-373	UT	Various	32,680,269	
Oregon-New Connect - Residential	360-373	OR	Various	26,844,118	
New Connect Investment Programs - D - UT	360-373	UT	Various	21,396,933	
Replacements Investment Programs - D - UT	360-373	UT	Various	20,497,018	
Utah-New Connect - Commercial	360-373	UT	Various	17,104,438	
Wildfire - Dist CA	360-373	CA	Various	16,872,580	
Distribution - OR	360-373	OR	Various	16,079,731	
Oregon Replace OH Dist Lines - Poles	360-373	OR	Various	15,621,929	
Conser Road- Construct New 115kV to 20.8 kV substation D	360-373	OR	Sep-23	15,068,384	8.4.35
Wildfire - Dist WA	360-373	WA	Various	11,800,884	
Customer 3 - UT - Dist	360-373	UT	Dec-23	11,509,199	
Replace Overhead Distribution Poles - UT	360-373	UT	Various	11,002,856	
U/G Cable Test & Replace	360-373	UT	Various	10,448,045	
Oregon Replace Storm and Casualty	360-373	OR	Various	10,390,189	
AMI - Utah Meters 2019 -2020	360-373	UT	Various	10,298,356	
New Revenue - Feeder Reinforcement - UT	360-373	UT	Various	10,263,754	
Customer 8 - UT - Dist (2)	360-373	UT	Various	10,039,809	
Replace Underground Vaults & Equipment - UT	360-373	UT	Various	9,891,575	
Malin - Bonanza New 69 kV line	360-373	OR	Various	9,464,091	
Customer 19 - UT - Dist	360-373	UT	Sep-24	9,266,901	
Customer 19 - UT - Dist (2)	360-373	UT	Sep-24	9,266,901	
Syracuse 138-13.2 kV Transformer	360-373	UT	Dec-23	9,052,492	
Skypark Second 138-12 kV Transformer	360-373	UT	Oct-23	8,928,031	
Spanish Fork Sub Install Transformer	360-373	UT	Dec-24	8,896,773	
Nibley 138/12 kV Transformer Addition	360-373	UT	Dec-24	8,731,679	
Customer 11 - UT - Dist	360-373	UT	Various	8,450,788	
New Connect Meters - New and Replacements - UT	360-373	UT	Various	8,250,834	
Copper Hills Install 2nd Xfmr	360-373	UT	Nov-23	8,196,077	
West Valley Install Second Xfmr	360-373	UT	Mar-24	7,990,062	
Elkhorn Install T#2, 30 MVA	360-373	WYP	Dec-24	7,940,935	
Jumbers Point Substation - Dist	360-373	UT	May-24	7,389,096	
Customer 23 - UT - Dist (2)	360-373	UT	Nov-23	7,371,411	
Warren Transformer Addition	360-373	UT	Dec-24	7,063,499	
Silver Creek Install Distribution Transformer	360-373	UT	Nov-24	6,802,858	
Walnut Grove Transformer Addition	360-373	UT	Dec-24	6,488,277	
Oregon-New Connect - Commercial	360-373	OR	Various	6,393,148	
Mandated Investment Programs - D - UT	360-373	UT	Various	6,307,777	
Nibley-Construct New 25 kV Circuit	360-373	UT	Nov-24	6,222,520	
Customer 14 - UT - Dist	360-373	UT	Sep-24	5,886,000	
Replace Overhead Distribution Lines - Crossarms & Cutouts - Dist - UT	360-373	UT	Various	5,807,334	
Grantsville Increase Capacity - Dist	360-373	UT	Various	5,762,536	
Mandated Highway Relocations - D - UT	360-373	UT	Various	5,637,358	
BDO: Install 2nd 138-12.5 kV, 30 MVA Xfmr	360-373	UT	Dec-23	5,634,216	
Targeted reliability Improvement, Dist - UT	360-373	UT	Various	5,625,498	
Distribution - OR - New Rev	360-373	OR	Various	5,589,782	
Upgrades Investment Programs - D - UT	360-373	UT	Various	5,480,914	
Washington-New Connect - Residential	360-373	WA	Various	5,475,157	
Oregon Cross-Arms & Cutouts RD	360-373	OR	Various	5,147,278	
Underground Cable Test & Replace V2	360-373	OR	Various	5,136,446	
Replacements Investment Programs - D - WY	360-373	WYP	Various	4,906,874	
Distribution System Hardening and Resiliency - OR	360-373	OR	Various	4,877,480	
Replace - Storm & Casualty - Dist UT	360-373	UT	Various	4,798,206	
Distribution - CA	360-373	CA	Various	4,667,089	
Replace Overhead Distribution Lines - Other - UT	360-373	UT	Various	4,543,960	
Replace Underground Cable - UT	360-373	UT	Various	4,543,157	
Replacements Investment Programs - D - ID	360-373	ID	Various	4,408,508	
Rigby 161-12kV Transformer Addition	360-373	ID	May-24	4,333,545	
Oregon Replace Overhead Dist Lines/Other	360-373	OR	Various	4,107,494	

PacifiCorp
Oregon General Rate Case - December 2025
Pro Forma Plant Additions and Retirements
Distribution Plant Additions

Project Description	FERC Account	Factor	Inservice Date	July23 to Dec24 Plant Adds	Ref.
Oregon - Mandated Highway Relocations	360-373	OR	Various	3,969,767	
Customer 6 - UT - Dist	360-373	UT	Apr-24	3,902,857	
Metering CT/VT Replacement OR	360-373	OR	Various	3,829,381	
Customer 10 - UT - Dist	360-373	UT	Jun-24	3,822,423	
Customer 1 - UT - Dist	360-373	UT	Jul-24	3,772,787	
Idaho-New Connect - Residential	360-373	ID	Various	3,667,772	
FLISR - Russellville Distrib Automation Project	360-373	OR	Jul-24	3,549,133	
Avian Protection - Dist WY	360-373	WYP	Various	3,530,243	
Replace Overhead Distribution Poles - ID	360-373	ID	Various	3,516,526	
TPU/DPU Relay Replacement Program - UT	360-373	UT	Various	3,432,709	
New Connect Investment Programs - D - WY	360-373	WYP	Various	3,417,159	
Downtown 8kV System Upgrade - Dist	360-373	UT	Various	3,363,440	
City of Medford Rd Widening/Lone Pine & Foothill Sub	360-373	OR	Dec-23	3,304,316	
Customer 25 - UT - Dist	360-373	UT	Dec-24	3,231,989	
Medford 115-12.5kV Capacity Increase	360-373	OR	Mar-24	3,209,177	
Washington- Mandated Highway Relocations	360-373	WA	Various	3,208,055	
New Connect Investment Programs - D - ID	360-373	ID	Various	3,203,194	
118th S 6400 W Substation Property Acquisition	360-373	UT	Dec-23	3,200,000	
Ruby 69-12kV Transformer Replacement	360-373	ID	May-24	3,198,757	
Distribution - WA	360-373	WA	Various	3,185,675	
OSU Reliability Replace Oil Switches and Junction Boxes	360-373	OR	Various	3,012,265	
Unspecified OR Distribution Reinforcement	360-373	OR	Various	2,974,671	
Pony Express Enable Mobile Installation	360-373	UT	Dec-23	2,970,857	
Customer 27 - UT - Dist	360-373	UT	Jun-24	2,924,356	
Washington-New Connect - Commercial	360-373	WA	Various	2,831,623	
Wildfire Mitigation Plan - WA D	360-373	WA	Various	2,794,831	
Moab City Replace Transformer #2 with 22.4 MVA	360-373	UT	Dec-23	2,768,689	
Distribution - CA - New Rev	360-373	CA	Various	2,766,817	
Avian Protection - Dist UT	360-373	UT	Various	2,755,548	
Garden City Transformer Upgrade	360-373	ID	May-24	2,634,724	
Canyon View - Purchase Substation Property	360-373	UT	Dec-24	2,617,394	
Customer 12 - UT - Dist (1)	360-373	UT	Various	2,524,495	
Replace Overhead Distribution Poles - WY	360-373	WYP	Various	2,521,841	
Wyoming-New Connect - Residential	360-373	WYP	Various	2,491,218	
Flint New 115kV to 12.5kV Substation Project- D	360-373	WA	Various	2,470,940	
Oregon-Mandated-Code Compliance-D	360-373	OR	Various	2,469,641	
Taylor Increase Capacity 30 MVA 46kV	360-373	UT	Feb-24	2,436,034	
Arches New Temp Substation (Disappearing Angel)	360-373	UT	Dec-23	2,420,131	
Dodd Road Transformer Replacement	360-373	WA	Nov-24	2,344,015	
Oregon Upgrade Spare Equipment Additions	360-373	OR	Various	2,322,439	
Customer 23 - UT - Dist (1)	360-373	UT	Apr-24	2,223,798	
Avian Protection - Dist ID	360-373	ID	Various	2,223,606	
Replace Underground Cable - WY	360-373	WYP	Various	2,168,755	
Customer 8 - UT - Dist (1)	360-373	UT	May-24	2,154,918	
Enoch Upgrade Transformer	360-373	UT	Dec-23	2,099,182	
Orange Upgrade to 30 MVA	360-373	UT	Various	2,098,437	
Customer 26 - ID - Dist	360-373	ID	Sep-24	2,057,998	
Washington Cross-Arms & Cutouts RD	360-373	WA	Various	2,015,793	
Wash Upgrade Feeder Improvements	360-373	WA	Various	1,962,967	
Customer 9 - UT - Dist	360-373	UT	Various	1,853,073	
Customer 4 - UT - Dist	360-373	UT	Aug-24	1,846,679	
Pole Failure Mitigation - Porcelain Cutout Replacement - Dist - UT	360-373	UT	Various	1,817,948	
Substation Gravel Additions/Replacements D OR	360-373	OR	Various	1,788,741	
Dorris Sub- Capacity solution-Transformer (9.4 MVA)	360-373	OR	Dec-23	1,682,424	
Avian Oregon - Spot & undefined Avian D	360-373	OR	Various	1,679,437	
System Reinforcement Investment Programs - D - UT	360-373	UT	Various	1,640,213	
Wyoming-New Connect - Commercial	360-373	WYP	Various	1,602,640	
Mandated Investment Programs - D - ID	360-373	ID	Various	1,598,825	
Parkside Add Mobile Connection	360-373	UT	Various	1,559,688	
California Cross-Arms & Cutouts RD	360-373	CA	Various	1,534,740	

PacifiCorp
Oregon General Rate Case - December 2025
Pro Forma Plant Additions and Retirements
Distribution Plant Additions

Project Description	FERC Account	Factor	Inservice Date	July23 to Dec24 Plant Adds	Ref.
Replace Overhead Distribution Lines - Crossarms & Cutouts - Dist - WY	360-373	WYP	Various	1,488,122	
Klamath Falls -Hornet 69 kv line 9, Reconductor 5.3 miles D	360-373	OR	Nov-23	1,480,862	
Wash Replace Storm and Casualty	360-373	WA	Various	1,396,859	
Replace Overhead Distribution Lines - Other - WY	360-373	WYP	Various	1,387,076	
Targeted reliability Improvement, Dist - WY	360-373	WYP	Various	1,365,897	
Targeted reliability Improvement, Dist - ID	360-373	ID	Various	1,363,272	
California-New Connect - Commercial	360-373	CA	Various	1,351,932	
Washington Replace Underground Cable	360-373	WA	Various	1,351,813	
Mandated OH/UG Conversions - UT	360-373	UT	Various	1,332,678	
Replace - Storm & Casualty - Dist WY	360-373	WYP	Various	1,316,886	
Transmission HMI Replacement Program	360-373	UT	Various	1,312,861	
Oregon Cross-Arms & Cutouts RI	360-373	OR	Various	1,294,939	
Distribution Oregon- Project >$1.0M	360-373	OR	Various	1,263,454	
Idaho-New Connect - Commercial	360-373	ID	Various	1,253,201	
Apple Valley Install New Dist Sub - Dist	360-373	UT	Nov-23	1,243,247	
New Revenue - Feeder Reinforcement - WY	360-373	WYP	Various	1,241,992	
System Reinforcement Investment Programs - D - WY	360-373	WYP	Various	1,209,508	
Replace Substation Meters and Relays - D - UT	360-373	UT	Various	1,027,033	
Oregon Upgrade Feeder Improvements	360-373	OR	Various	1,023,087	
Misc Small Projects	360-373	UT	Various	1,009,604	
Replace Underground Vaults & Equipment - WY	360-373	WYP	Various	1,008,858	
TPU/DPU Relay Replacement Program - WY	360-373	WYP	Various	1,008,792	
Distribution - WA - New Rev	360-373	WA	Various	1,005,784	
Linerupter Switch Replacement Program	360-373	ID	Various	1,004,851	
Replace Overhead Distribution Lines - Other - ID	360-373	ID	Various	1,004,835	
Projects Less Than $1million	360-373	UT	Various	20,022,929	
Projects Less Than $1million	360-373	ID	Various	9,249,876	
Projects Less Than $1million	360-373	WYP	Various	6,365,170	
Projects Less Than $1million	360-373	OR	Various	2,042,322	
Projects Less Than $1million	360-373	WA	Various	1,870,956	
Projects Less Than $1million	360-373	CA	Various	198,552	
Distribution Plant Five Year Average Removals	360-373	ID	Various	(2,155,051)	
Distribution Plant Five Year Average Removals	360-373	CA	Various	(2,499,462)	
Distribution Plant Five Year Average Removals	360-373	WA	Various	(3,530,771)	
Distribution Plant Five Year Average Removals	360-373	WYP	Various	(5,580,914)	
Distribution Plant Five Year Average Removals	360-373	OR	Various	(17,497,224)	
Distribution Plant Five Year Average Removals	360-373	UT	Various	(20,511,196)	
				973,476,245	

PacifiCorp
Oregon General Rate Case - December 2025
Pro Forma Plant Additions and Retirements
General Plant Additions

Project Description	FERC Account	Factor	Inservice Date	July23 to Dec24 Plant Adds	Ref.
Juniper Ridge Bend Svc Ctr	397	OR	Dec-24	40,343,412	8.4.35
Replace Vehicles - UT	397	UT	Various	16,457,466	
Oregon Replace Deteriorated Vehicles	397	OR	Various	15,563,827	
PacifiCorp Accellerated RTU Repl (PARR)	397	SO	Various	10,800,000	8.4.35
Open Floor Plan - OR Structures	397	SO	Various	7,043,598	
Eng Telecom : OTLM - T1	397	SO	Dec-24	5,908,076	
OT Lease Modernization - T1 Circuits	397	SO	Various	5,908,076	
Replace Other General Plant - OR	397	OR	Various	5,358,698	
Washington Repl Deteriorated Vehicles	397	WA	Various	4,834,797	
Rock Springs Service Center Purchase	397	WYP	Various	3,937,727	
Replacements Investment Programs - Situs G - UT	397	UT	Various	3,900,758	
Oregon Replace Other General Plant	397	OR	Various	3,541,086	
Oregon Replace Tools	397	OR	Various	3,342,358	
Data Center Consolidation	397	SO	Various	2,700,000	
Replace Vehicles - ID	397	ID	Various	2,609,490	
Eng Telecom PP R9	397	SO	Various	2,535,202	
Corporate Router/Switch TOM 20/21	397	SO	Aug-23	2,488,043	
Replace Other General Plant - UT	397	UT	Various	2,480,033	
AR Training Modules Project-Field Operations	397	SO	Various	2,430,879	
Storage capacity and obsolescence management	397	SO	Various	2,384,262	
Replace Vehicles - WY	397	WYP	Various	2,346,952	
Calapooya to Mckenzie Fiber Install	397	SO	Nov-23	2,303,076	
PAC PC Lifecycle Budget	397	SO	Various	2,214,340	
Linux capacity and obsolescence management	397	SO	Various	2,192,508	
Eng Telecom RMP R9	397	SO	Various	2,118,720	
Replace Vehicles - Electric Purchase	397	UT	Various	2,073,452	
NTO Campus, Salt Lake Service Center Relocation	397	UT	Various	1,834,709	
Replace Other General Plant - WY	397	WYP	Various	1,821,674	
2900 TOM Repl (EAST)	397	SO	Various	1,747,983	
Cutler to Rabbit Mtn MW Replacement	397	SO	Jun-24	1,659,920	
Substation Endpoint Lifecycle	397	SO	Various	1,620,000	
Replace Tools - UT	397	UT	Various	1,591,662	
Corporate Communication Modernization	397	SO	May-24	1,530,307	
Corporate Communications Modernization / E-911 Compliance	397	SO	Dec-24	1,530,307	
Common Virtualization / Windows Server capacity and TOM	397	SO	Various	1,458,000	
Calif Replace Deteriorated Vehicles	397	CA	Various	1,409,983	
Eng Telecom PP R8	397	SO	Various	1,309,612	
Eng Telecom RMP U5	397	SO	Various	1,285,200	
Eng Telecom RMP R8	397	SO	Various	1,272,964	
Eng Telecom RMP U7	397	SO	Various	1,186,920	
AR Training Modules Project-Communications Tech	397	SO	Various	1,170,798	
Alvey 230 to McKenzie Fiber Install	397	SO	Dec-23	1,162,243	
Structures - OR	397	OR	Various	1,155,542	
Vehicles - OR	397	OR	Various	1,098,876	
FCS Hardware Upgrade	397	SO	Oct-23	1,063,810	
Projects Less Than $1million	397	SO	Various	27,535,621	
Projects Less Than $1million	397	WYP	Various	3,409,936	
Projects Less Than $1million	397	UT	Various	3,125,969	
Projects Less Than $1million	397	ID	Various	1,686,389	
Projects Less Than $1million	397	WA	Various	1,672,498	
Projects Less Than $1million	397	SG	Various	1,515,294	
Projects Less Than $1million	397	OR	Various	1,136,091	
Projects Less Than $1million	397	CA	Various	636,146	
General Plant Five Year Average Removals	397	SO	Various	(1,733,228)	
				223,712,063	

PacifiCorp
Oregon General Rate Case - December 2025
Pro Forma Plant Additions and Retirements
Intangible Plant Additions

Project Description	FERC Account	Factor	Inservice Date	July23 to Dec24 Plant Adds	Ref.
Oracle Systems-Customer	303	SO	Various	154,749,340	8.4.36
PAC FIPS 201 Pinnacle Repl	303	SO	Various	18,100,000	8.4.36
APIM-Asset Performance and Investment Mg	303	SO	Various	7,198,357	
Field Ai-Field Asset Intelligence- GWD	303	SO	Apr-24	6,328,789	
BHE Customer Mobile Apps	303	SO	Sep-24	3,796,775	
Dell TLA Expansion	303	SO	Sep-23	3,126,969	
Wave 1 Sustainment	303	SO	Mar-24	2,506,911	
OpenMethods for Oracle	303	SO	Sep-24	1,990,005	
EBI Data & Analytics Cognizant Labor/Use cases	303	SO	Various	1,841,408	
PAC SolarWinds	303	SO	Dec-24	1,545,251	
Ambient Software	303	SO	Jun-24	1,466,472	
Endur Upgrade/Repl	303	SO	Oct-23	1,437,199	
F5 License	303	SO	Aug-24	1,272,000	
AN049 Varasset	303	SO	Mar-24	1,227,615	
EPM Affiliate Planning- UII	303	SO	Apr-23	1,179,945	
iTOA Enhancements	303	SO	Nov-24	1,146,244	
BHE ESRI Enterprise Agreement	303	SO	Aug-23	1,118,840	
Legacy Oasis Replacement	303	SO	Feb-24	1,069,009	
Projects Less Than $1million	303	SO	Various	16,334,068	
				227,435,196	

PacifiCorp
Oregon General Rate Case - December 2025
Pro Forma Plant Additions and Retirements
Plant Retirements
5 Year Average Retirement Amount

Function	Factor	FY2019 (CY2018) Retirements	FY2020 (CY2019) Retirements	FY2021 (CY2020) Retirements	FY2022 (CY2021) Retirements	FY2023 (CY2022) Retirements	Large Items to Exclude	5 Year Avg	Monthly Amount
STMP	DGU	(3,805,358)	(27,141,648)	(2,191,253)	(2,596,560)	(4,405,413)	25,445,534	(2,938,940)	(244,912)
STMP	DGP	(4,346,678)	(4,077,521)	(2,667,943)	(3,146,449)	(2,475,103)	-	(3,342,739)	(278,562)
STMP	SSGCH	-	-	-	-	-	-	-	-
STMP	SG	(41,678,721)	(72,453,873)	(30,626,315)	(29,922,896)	(59,114,223)	34,778,221	(39,803,561)	(3,316,963)
STMP	NUTIL	-	-	-	(29,653,867)	(534,481)	-	(6,037,670)	(503,139)
		(49,830,757)	(103,673,042)	(35,485,512)	(65,319,772)	(66,529,220)	60,223,755	(52,122,910)	(4,343,576)
HYDP	SG-U	(669,210)	(688,887)	(596,216)	(361,746)	(685,344)	-	(600,280)	(50,023)
HYDP	SG-P	(3,174,454)	(2,760,652)	(4,743,569)	(1,821,775)	(73,605,770)	72,125,585	(2,796,127)	(233,011)
HYDP	DGU	(523,331)	(406,073)	(819,933)	(100,113)	(171,368)	-	(404,164)	(33,680)
HYDP	DGP	(874,490)	(460,328)	(703,798)	(89,052)	(29,202,213)	28,945,380	(476,900)	(39,742)
HYDP	NUTIL	-	-	-	-	-	-	-	-
		(5,241,484)	(4,315,941)	(6,863,517)	(2,372,686)	(103,664,695)	101,070,965	(4,277,471)	(356,456)
OTHP	DGU	-	-	-	-	-	-	-	-
OTHP	SG	(16,761,294)	(963,453)	(50,697,982)	(24,921,087)	(21,405,307)	-	(22,949,825)	(1,912,485)
OTHP	SG-W	(82,725)	(844,072,708)	(412,145,767)	(38,861,784)	(152,495)	1,292,584,429	(546,210)	(45,518)
OTHP	SSGCT	(2,256,844)	73,283	-	(38,029)	(1,745,767)	-	(793,471)	(66,123)
OTHP	NUTIL	-	-	-	(3,531,744)	-	-	(706,349)	(58,862)
		(19,100,863)	(844,962,878)	(462,843,749)	(67,352,644)	(23,303,570)	1,292,584,429	(24,995,855)	(2,082,988)
TRNP	DGP	(1,293,599)	(2,194,511)	(2,231,965)	(1,451,081)	(4,120,136)	-	(2,258,258)	(188,188)
TRNP	DGU	(7,288,536)	(2,125,822)	(2,425,425)	(4,049,253)	(5,021,355)	-	(4,182,078)	(348,507)
TRNP	JBG	-	-	-	-	-	-	-	-
TRNP	SG	(7,082,678)	(9,584,949)	(9,274,706)	(19,689,386)	(21,221,243)	1,302,096	(13,110,173)	(1,092,514)
TRNP	NUTIL	-	-	-	-	-	-	-	-
		(15,664,813)	(13,905,283)	(13,932,096)	(25,189,720)	(30,362,734)	1,302,096	(19,550,510)	(1,629,209)
DSTP	CA	(4,729,076)	(1,367,157)	(1,186,564)	(1,113,791)	(4,381,160)	119,884	(2,531,573)	(210,964)
DSTP	ID	(2,203,340)	(1,930,395)	(1,813,227)	(4,057,391)	(15,975,382)	-	(5,195,947)	(432,996)
DSTP	MT	-	-	-	-	-	-	-	-
DSTP	OR	(42,097,594)	(33,806,510)	(12,101,471)	(12,071,494)	(14,340,164)	466,200	(22,790,206)	(1,899,184)
DSTP	UT	(16,986,844)	(16,190,768)	(18,052,141)	(27,561,114)	(40,098,584)	-	(23,777,890)	(1,981,491)
DSTP	WA	(2,504,228)	(3,224,732)	(2,535,929)	(1,848,462)	(3,269,263)	-	(2,676,523)	(223,044)
DSTP	WYP	(3,122,221)	(3,763,963)	(3,192,347)	(3,261,905)	(4,136,731)	-	(3,495,433)	(291,286)
DSTP	WYU	(296,106)	(325,291)	(430,096)	(590,090)	(1,093,567)	-	(547,030)	(45,586)
DSTP	NUTIL	-	-	-	-	-	-	-	-
		(71,939,410)	(60,608,816)	(39,311,775)	(50,504,246)	(83,294,850)	586,084	(61,014,603)	(5,084,550)
GNLP	SE	(130,808)	(36,551)	(467,235)	(29,091)	(5,428)	-	(133,822)	(11,152)
GNLP	SSGCT	-	-	-	-	(4,039)	-	(808)	(67)
GNLP	SG	(5,290,627)	(4,624,892)	(10,925,287)	(12,711,663)	(4,050,765)	-	(7,520,647)	(626,721)
GNLP	DGP	(10,091)	(55,490)	(168,438)	(301,777)	(12,331)	-	(109,625)	(9,135)
GNLP	DGU	(70,539)	(115,871)	(1,244,766)	(37,080)	(154,153)	-	(324,482)	(27,040)
GNLP	SO	(12,881,251)	(25,844,820)	(13,374,457)	(17,864,045)	(13,217,260)	-	(16,636,367)	(1,386,364)
GNLP	CN	(3,163,468)	(384,219)	(797,489)	(957,283)	(1,113,459)	-	(1,283,184)	(106,932)
GNLP	CA	(715,495)	(717,531)	(981,422)	(931,410)	(156,213)	-	(700,414)	(58,368)
GNLP	ID	(1,368,673)	(1,285,289)	(429,609)	(612,386)	(1,204,151)	-	(980,021)	(81,668)
GNLP	SSGCH	-	-	-	-	-	-	-	-
GNLP	OR	(5,945,198)	(4,543,677)	(1,961,890)	(21,521,367)	(2,751,204)	-	(7,344,667)	(612,056)
GNLP	UT	(7,770,797)	(4,139,974)	(8,951,496)	(2,688,767)	(2,359,946)	-	(5,182,196)	(431,850)
GNLP	WA	(1,132,533)	(2,705,376)	(604,195)	(1,358,617)	(720,233)	-	(1,304,191)	(108,683)
GNLP	WYU	(493,517)	(343,869)	(235,183)	(223,670)	(160,934)	-	(291,435)	(24,286)
GNLP	WYP	(3,446,458)	(2,626,180)	(1,527,523)	(1,512,481)	(1,916,806)	-	(2,205,890)	(183,824)
GNLP	NUTIL	-	-	-	-	-	-	-	-
		(42,419,454)	(47,423,739)	(41,668,990)	(60,749,636)	(27,826,920)	-	(44,017,748)	(3,668,146)
MNGP	SE	-	-	-	-	-	-	-	-
MNGP	NUTIL	-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-
INTP	JBG	-	-	-	-	-	-	-	-
INTP	SG-P	-	(279,935)	-	-	(74,111,750)	74,111,750	(55,987)	(4,666)
INTP	SG-U	-	-	(895,226)	-	-	-	(179,045)	(14,920)
INTP	SG	(1,546,900)	(62,921)	(1,268,060)	(103,096)	(115,548)	58,061	(607,693)	(50,641)
INTP	SO	(5,104,327)	(8,329,898)	(6,745,772)	(9,053,968)	(9,276,593)	-	(7,702,112)	(641,843)
INTP	CN	(10,680)	(8,081)	-	(8,201,332)	-	-	(1,644,019)	(137,002)
INTP	SE	(14,653)	-	-	-	-	-	(2,931)	(244)
INTP	DGU	-	-	-	(123,397)	-	-	(24,679)	(2,057)
INTP	CA	-	-	-	-	(580)	-	(116)	(10)
INTP	ID	-	-	-	-	(1,727)	-	(345)	(29)
INTP	OR	(21,797)	-	-	-	(2,351)	-	(4,830)	(402)
INTP	UT	-	-	(5,507)	(12,582)	32,081,215	(32,081,215)	(3,618)	(301)
INTP	WA	-	-	-	-	-	-	-	-
INTP	WYU	-	-	-	-	-	-	-	-
INTP	WYP	-	-	-	-	(157,662)	-	(31,532)	(2,628)
		(6,698,358)	(8,680,835)	(8,914,565)	(17,494,375)	(51,584,995)	42,088,596	(10,256,906)	(854,742)
		(210,895,138)	(1,083,570,534)	(609,020,203)	(288,983,079)	(386,566,984)	1,497,855,925	(216,236,003)	(18,019,667)
								Without NUTIL	(17,457,665)

STEAM PLANT ADDITIONS:

Jim Bridger - CCR Jim Bridger FGD Pond 3 (In-Service Date-September 2023), (Reference page 8.4.19)
Development and construction of a mixed-use impoundment for the management of coal combustion residuals (CCR) specifically flue gas desulfurization (FGD) and wastewater effluent. Due to a recent court decision (U.S. Court of Appeals for the District of Columbia) the existing FGD Pond 2 must be closed because it is an unlined impoundment. Under the current CCR rules for the alternative closure, a new FGD Pond must be placed in-service by October 2023 because FGD Pond 2 will no longer be allowed to accept CCR waste. A new CCR compliant mixed use FGD and effluent impoundment will provide Jim Bridger with a CCR-compliant disposal and effluent site for continued, uninterrupted operation.

Jim Bridger - U1 Conversion to Natural Gas (In-Service Date-April 2024), (Reference page 8.4.19)
The Company's 2021 Integrated Resource Planning process identified a preferred portfolio that includes the conversion of Jim Bridger Unit 1 as a 100% natural gas-fired resource. Emissions requirements imposed by the EPA would require additional emission control equipment for the unit to continue to run as a coal-fired unit beyond December 31, 2023. Conversion to a gas-fired unit provides a more economically viable option while also helping to maintain grid stability and reliability. Estimated capacity for Unit 1 as a gas-fired unit will remain consistent with its coal-fired capacity as well.

Jim Bridger - U2 Conversion to Natural Gas (In-Service Date-April 2024), (Reference page 8.4.19)
The Company's 2021 Integrated Resource Planning process identified a preferred portfolio that includes the conversion of Jim Bridger Unit 2 as a 100% natural gas-fired resource. Emissions requirements imposed by the EPA would require additional emission control equipment for the unit to continue to run as a coal-fired unit beyond December 31, 2023. Conversion to a gas-fired unit provides a more economically viable option while also helping to maintain grid stability and reliability. Estimated capacity for Unit 2 as a gas-fired unit will remain consistent with its coal-fired capacity as well.

HYDRO PLANT ADDITIONS:

IKL-Fall Creek Hatchery (In-Service Date-March 2024), (Reference page 8.4.20)
The Iron Gate Hatchery is owned by PacifiCorp and operated by the California Department of Fish and Wildlife. The Iron Gate Dam provides supply water to the Iron Gate Hatchery through the powerhouse intake structure. With the planned removal of the Lower Klamath Project dams (J.C. Boyle, Copco No. 1, Copco No. 2, and Iron Gate) as early as January 2024, there will no longer be water supply for Iron Gate Hatchery from Iron Gate reservoir, and fish collection facilities at the base of Iron Gate Dam will be removed. Under Interim Measure 20 (IM20) of the KHSA, signed on February 18, 2010, and amended on April 6, 2016, and November 30, 2016, PacifiCorp is obligated to provide continued hatchery production for 8-years after the removal of Iron Gate Dam.

In order to meet the obligation stated in IM20 of the KHSA, PacifiCorp will construct a new fish hatchery facility at the location of the Fall Creek hydroelectric development. This project will include implementation of a facility design that has been developed by the Klamath River Renewal Corporation in consultation with the California Department of Fish and Wildlife and the National Marine Fisheries Service, acquisition of permits, rehabilitation of existing hatchery raceways at the site, and construction of the new Fall Creek Hatchery.

ILR 4.5 Yale Downstream Fish Passage (In-Service Date-October 2024), (Reference page 8.4.20)
In accordance with the Federal Energy Regulatory Commission (FERC) Licenses for the Lewis River Hydroelectric Projects, the National Marine Fisheries Service and the U.S. Fish and Wildlife Service (together, the Services) completed their process for determining the appropriateness of fish passage measures into Yale Reservoir. By their October 27, 2021, Determination Letter to the Licensees for the Lewis River Project, PacifiCorp, and Cowlitz County Public Utility District No. 1, and to the parties of the Lewis River Settlement Agreement, the Services determined that fish passage into Yale Reservoir remains appropriate. The Services determined that reintroduction of salmonids to Yale Reservoir and its tributaries will more reliably meet productivity and abundance Viable Salmonid Population (VSP) parameters than an in-lieu alternative of habitat restoration. Additionally, the Services note a Yale Reservoir fish passage facility provides spatial structure and diversity gains in VSP parameters over an in-lieu restoration.

The Yale Downstream Construction Project is located upstream of Yale Dam on the Lewis River in southern Washington and is part of the Yale Hydroelectric Project (Federal Energy Regulatory Commission [FERC] Project No. 2071). This project will construct a floating fish collector on Yale Reservoir to collect downstream migrating federally listed salmonids and transport them downstream of the Merwin Hydroelectric Project. The floating fish collector will be constructed to meet National Oceanic and Atmospheric Administration Fisheries (NOAA Fisheries) fish passage criteria and provide for monitoring and evaluation of collected fish. This project, in coordination with other Lewis River fish passage projects, will reestablish salmon and steelhead access to historical habitat in accordance with the Lewis River Settlement Agreement and FERC licenses for the Merwin, Yale and Swift No. 1 hydroelectric projects.

OTHER PLANT ADDITIONS:

Foote Creek 2-4 Repowering (In-Service Date-November 2023), (Reference page 8.4.21)
This project will provide reliable and cost-effective renewable energy to customers by purchasing safe harbor equipment to qualify repowered wind projects interconnected to PacifiCorp's system and acquire and repower the 43.35 MW Foote Creek II-IV facilities, qualifying the project for production tax credits and generating zero fuel cost energy for customers at favorable cost.

Repowering will entail the decommissioning of the existing 64 wind turbines at the project site with nameplate ratings between 600 kW and 750 kW and the installation of up to 15 new, modern turbines. The extraordinary wind resource at the Foote Creek Rim site location is estimated to result in a repowered facility with a capacity factor approaching 50 percent. Earlier purchase of the master wind energy lease rights for the site results in favorable land rights payments as compared to current market rates and contributes to the favorable economics of the project. PacifiCorp acquired the project from Terra-Gen in June 2022. All project contracts are executed and in place. Construction activity began in June 2022 and the project is on track to achieve the anticipated in-service date.

Lake Side - U21 Major Inspection Overhaul - CY23 (In-Service Date-October 2023), (Reference page 8.4.21)
Performance of the Unit 21 Major Inspection (MI) overhaul pursuant to the Managed Long Term Gas Turbine Parts and Service Contract (LTP) between PacifiCorp and Siemens Energy, Inc.
In accordance with the LTP, Major Inspection (MI) is to be conducted when the combustion turbine reaches 33,200 hours relative to the last combustion inspection outage which was performed in 2018. Combustion internal extension program parts are to be supplied and delivered by Siemens for installation during this Major Inspection scheduled outage on Combustion Turbine 21 per the LTP. This project, according to the LTP, requires Siemens to prove the equipment will operate another 33,200 hours after completion of the Major Inspection.

Lake Side - U22 Major Inspection Overhaul - CY23 (In-Service Date-October 2023), (Reference page 8.4.21)
Performance of the Unit 22 Major Inspection (MI) overhaul pursuant to the Managed Long Term Gas Turbine Parts and Service Contract (LTP) between PacifiCorp and Siemens Energy, Inc.
In accordance with the LTP, Major Inspection (MI) is to be conducted when the combustion turbine reaches 33,200 hours relative to the last combustion inspection outage which was performed in 2018. Combustion internal extension program parts are to be supplied and delivered by Siemens for installation during this Major Inspection scheduled outage on Combustion Turbine 22 per the LTP. This project, according to the LTP, requires Siemens to prove the equipment will operate another 33,200 hours after completion of the Major Inspection.

TRANSMISSION PLANT ADDITIONS:

Gateway South Aeolus Mona 500kV Line (In-Service Date-December 2024), (Reference page 8.4.22)
This project builds a new 416-mile 500 kV transmission line from the Aeolus substation, near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah. The project in conjunction with the Windstar to Shirley Basin 230 kilovolt transmission line will facilitate integration of 2,030 MW of Wyoming low-cost renewable energy resources with delivery to PacifiCorp customers and potential market loads, improve reliability of the transmission system by providing redundant capacity between Gateway West and Gateway Central, and relieve transmission congestion on the existing Wyoming transmission system. The Gateway South line allows transfers of up to 1,700 MW from eastern Wyoming to central Utah.

Gateway West Segment D1:Windstar-Shirley Basin 230kV Line (In-Service Date-Various), (Reference page 8.4.22)
This project rebuilds 58 miles of an existing 230 kilovolt transmission line from the Windstar substation near Glenrock east of Casper, Wyoming, to the existing Amasa substation to a new, Heward substation, adjacent to Tri-State's Difficulty substation to the Shirley Basin substation near Medicine Bow, in central Wyoming. The project also includes construction of a new 230 kilovolt line of approximately 57 miles from the Windstar substation, east of Casper, Wyoming to Shirley Basin substation, northeast of Medicine Bow, Wyoming in central Wyoming. Additions will also be made to existing substations at Shirley Basin, Dave Johnson and Windstar substations and minor modifications at the Amasa substation. The Gateway West Sub-segment D1 Windstar to Shirley Basin 230 Kilovolt transmission line is being considered to address transmission reliability and interconnection constraints in the eastern Wyoming transmission system. The addition of this project, in conjunction with Gateway South (Segment F) will allow interconnection of an additional 2,030 megawatts of renewable generation resources in eastern Wyoming. It will increase transfer capability by approximately 750 MW from the Windstar/Dave Johnston area south to Shirley Basin/Aeolus in turn will support approximately 1,700 megawatts of transfer capability from eastern Wyoming (Aeolus) to the central Utah energy hub (Mona/Clover).

Anticline 345 kV Phase Shifter (In-Service Date-November 2024), (Reference page 8.4.22)
This project installs four 345 kV phase shifting transformers (533.3/597.3 MVA) at Anticline substation, near Point of Rocks Wyoming. The Anticline phase shifters will enhance transmission utilization of the both the Gateway West and Gateway South Projects that is necessary to maximize the production of eastern Wyoming renewable generation resources.

Oquirrh Terminal 345kV Line (In-Service Date-November 2024), (Reference page 8.4.22)
This project constructs a new double circuit approximately fourteen miles transmission line between Oquirrh substation, in West Jordan Utah, north to the Terminal substation, located south of the Salt Lake City international airport. This section of new transmission will link together the already completed Mona to Oquirrh and Populus to Termina transmission line to complete the Gateway Central portion of the Energy Gateway Transmission Expansion. This project mitigates transmission constraint between the Mona area and Wasatch front, increases path transfer capacity by 511 MW and meets long term capacity needs for Salt Lake County. The project allows for more solar generation to move north while serving the load in the Wasatch front.

Project Specialized (In-Service Date-Various), (Reference page 8.4.22)
Project Specialized is a customer driven major load addition of 242 MW near Hermiston, Oregon. System impact studies performed by Transmission Planning have determined that there are no suitable Company-owned facilities at or near the project site that could serve this load. The following service plans were developed to allow for these loads to be served in the most expedient manner possible:

Project Specialized (Customer requested ISD – June 2024):

- A specific customer has indicated that their nearby 115 kV facilities have adequate capacity for this load if converted to 230 kV, and their near-term plans call for construction of a 230 kV switchyard near this site.
- Company will execute a line and load interconnection request with a specific customer's system for necessary upgrades and redundant service from the planned specific customer's switchyard.
- Company will construct two (2) transmission lines, 1.5 miles each, from the specific customer's switchyard to a new substation near Project Specialized.
- Company will construct a new 230-34.5 kV substation near the Project Specialized substation to serve this load.
- Preliminary cost estimate: $146.5m, including a specific customer's work to construct a new 230 kV switchyard and convert a portion of their 115 kV system to 230 kV.

Path C Transmission Improvements (In-Service Date-May 2024), (Reference page 8.4.22)
This project will add a new 345/138 kV source in northern Utah and southeast Idaho by looping the existing Populus – Terminal 345 kV line in and out of the Bridgerland substation as well as Ben Lomond substation. The project also includes upgrades at Bridgerland substation including a 345/138 kV 700 MVA autotransformer; a new 345 kV bus; three 345 kV breakers; and four 138 kV breakers. This new 345/138 kV source will improve the reliability of the 138 kV system, which runs parallel to Path C, will maintain and possibility increase the path rating of the current WECC Path C and add operational flexibility under outage conditions at Ben Lomond substation.

Customer 8 - UT - Trans (1) (In-Service Date-Various), (Reference page 8.4.22)
This project will upgrade the substation to allow for the installation of a new 345-138kV 700 MW transformer at Oquirrh Substation and to increase the revenue metering rating at the Customer's existing point of delivery to accommodate Customer's increase in load request to 200 MW. These improvements correct two overload conditions on the surrounding system. If improvements weren't made it would cause the following:

- Loss of the Oquirrh #5 345-138 kV transformer is projected to result in the South Jordan Tap - 90th South 138 kV line loading to 124% of its 425 MVA summer emergency rating in summer 2023.
- Steady state power flow analysis indicates that the Customer's load addition is projected to result in the South Jordan Tap - 90th South 138kV line loading to 120% of its 244 MVA summer continuous rating in 2023.

Gateway South 230kV Supporting Projects (In-Service Date-December 2024), (Reference page 8.4.22)
This project installs one 41.6 MVAr shunt capacitor bank at Riverton substation and two 30 MVAr shunt capacitor banks at Mustang substation, both located in Wyoming. With the addition of the Gateway South project, addition of these shunt capacitors supports the additional power that flows through the Riverton – Wyopo 230 kV line and Mustang – Bridger 230 kV line under outage conditions and alleviates low voltage issues while maintaining the reliability and flows through that area.

Enhanced Substation Security (In-Service Date-August 2024), (Reference page 8.4.22)
This project is to develop a plan for more robust security measures at 25 key substations located in Rocky Mountain Power service territory and to purchase and install the materials and equipment necessary to execute the increased security plan at the four highest priority locations. This project is in response to increased incidents of hostile attacks on substations and utility equipment in North America. Specific criteria are being developed to assess the highest priority substations and equipment that will be most vulnerable to high velocity projectile and vehicle attack.

Threats to the power delivery system are expected to be significantly improved by adding protection in areas listed below. Each substation as assessed will utilize installation of some, or possibly all, of the possible scopes of protection identified below.

- Vehicle impact resistant entry gating to withstand a 50-mph impact.
- Taller security gate, minimum of 14 feet with full Level 10 ballistics rating.
- Taller security fence, minimum of 14 feet tall, Level 10 ballistics.
    - Concrete masonry wall construction, with full grout.
    - Precast concrete wall.
- Taller security fence, minimum of 14 feet tall, no ballistics
    - Concrete masonry wall construction, no grout fill.
    - Precast concrete wall
- Transformer protection wrap with Level 10 ballistics rating. (Custom designed for each transformer)
- Replacement of glass/oil bushings with polymer at each transformer to eliminate potential flash fire from projectile impact.

Klamath Falls - Snow Goose 230kV Line No. 2 TPL (In-Service Date-August 2023), (Reference page 8.4.22)
This project built a second 230 kV transmission line from Snow Goose to Klamath Falls substation located in Klamath County, Oregon. The project was 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 new transmission line also mitigates risks on the existing system by reinforcing the area's 230 kV system with a new source from Snow Goose substation.

Fort Hall/BIA Goshen Kinport 2310(1185), (In-Service Date-December 2023), (Reference page 8.4.22)
The purpose of this project is to pay for costs associated with the renewal of the Goshen-Kinport 345kV transmission line permit across the Fort Hall Reservation. PacifiCorp owns transmission facilities where right of way is required across tribal lands. The payment of permit costs and fees are essential for continued operation of company assets located on tribal and/or allotted lands.

DISTRIBUTION PLANT ADDITIONS:

Conser Road- Construct New 115kV to 20.8 kV substation D (In-Service Date-September 2023), (Reference page 8.4.24)
This project constructs a new 115 kV to 20.8 kV distribution substation to initially include one 30 MVA 115-20.8 kV transformer with one switchgear and a two-stage capacitor near the Millersburg area in Oregon. The new substation will provide up to 120 MVA of capacity for industrial development in the Millersburg area.

GENERAL and INTANGIBLE PLANT ADDITIONS:

Juniper Ridge Bend Svc Ctr (In-Service Date-December 2024), (Reference page 8.4.27)
Juniper Ridge Bend Service Center project consists of the construction of a new service center at company owned, undeveloped Juniper Ridge 19-acre property in Bend, Oregon. This new site consolidates the three Bend-area operating centers (the leased Bend Service Center and Bend Metering Office, and the owned Bend Substation Ops) into one location and resolve end-of-lease risks for the Bend Service Center and Bend Metering Office.

The new service center will be built on 15 acres of the 19-acre parcel we own. The new central Oregon training yard will be built on two of the 19 acres under a separate project. The remaining two acres will be held for future use. Having the service center located next to the training yard will provide the ability to incorporate the training rooms (workshops/classroom, instructor space) into the new service center and use is as a centralized craft training center for Pacific Power.

The new service center building will incorporate the open floor plan design in the office area, installing new sit/stand desks and furniture and other design elements.

The project started in 2019 and is expected to be completed in 2024. The service center will include an office, truck bays, warehouse, meter/wireroom, mechanic shop, yard storage and parking and conference/learning space. For the site design, we will include Bend area operations personnel and other stakeholders.

PacifiCorp Accelerated RTU Repl (PARR) (In-Service Date-Various), (Reference page 8.4.27)
A large number of SCADA (Supervisory Control and Data Acquisition) remote terminal units (RTUs) in PacifiCorp's fleet have become obsolete and are increasingly at risk of causing operational system impacts due to equipment failure. RTUs play a central role in the control and collection of data from critical substation equipment, including transformers, breakers, etc. Replacement of obsolete SCADA equipment will not only increase reliability while reducing O&M costs but will improve the company's ability to collect vital operational information from modern substation devices.
This effort provides a framework for a large-scale replacement of PacifiCorp's legacy SCADA devices (RTUs), located at numerous sites throughout PacifiCorp's service area. These RTUs collect vital operational data to grid operators for power flow management and provide crucial remote-control capability of critical grid devices, such as transformers, breakers, etc.
By implementing a large-scale replacement program targeting obsolete RTUs, the business is expected to benefit from a modern SCADA infrastructure while reducing the increasing risk of critical SCADA equipment failure. The solution involves replacing legacy RTUs with PacifiCorp's current standard (based on the NovaTech Orion architecture), while upgrading communication networks that support them, where necessary.

Oracle Systems-Customer (In-Service Date-Various), (Reference page 8.4.28)
Data and common enterprise systems are key components to transforming PacifiCorp to meet customer expectations. Many of our core processes were implemented over two decades ago and were not designed to accommodate the simplicity, automation, and digital interfaces necessary to respond to evolving customer expectations. Our data, traditionally collected for historical records, lacks the required structure and consistency to provide more meaningful insight into our business. By harnessing the value of data, we can better position our business to quickly benchmark performance, provide real-time reporting and analytics, and generate machine learning insights to deliver new value and exceptional customer service. Currently, BHE affiliate companies use a variety of IT enterprise systems and applications for similar purposes. This not only results in duplicate system solutions existing within the BHE affiliate companies, it also makes the consolidation of information across affiliates difficult, hinders the sharing of information and ensures that back-office skills are not portable between affiliates. While PacifiCorp anticipates significant operational efficiencies as a result of the sharing of human resources, supplies and materials, and information among affiliates, the amount of IT cost reductions alone provide sufficient benefits to justify the project costs.

PAC FIPS 201 Pinnacle Repl (In-Service Date-Various), (Reference page 8.4.28)
PacifiCorp's legacy PACS, Pinnacle, is outdated and not capable of complying with the BHE Information Security Policy requirements. It relies on proprietary components and is only capable of complying with various regulatory standards, including NERC CIPS, due to heavy after-market customization that has locked PacifiCorp into sole-source procurement agreements with the only supporting vendor in PacifiCorp's geographic territory. Berkshire Hathaway Energy Information Security Policy: 210, Physical Security Controls Policy. 210.1.2 Physical Access Control Systems requires:
Newly acquired or upgraded Physical Access Control Systems must meet or exceed the system specifications of the National Institute of Standards and Technology Federal Information Processing Standard (FIPS) 201-2 Personal Identity Verification (PIV) of Federal Employees and Contractors

PacifiCorp
Oregon General Rate Case - December 2025
Customer Advances for Construction

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Customer Advances	252	1	(268,999)	CA	Situs	-	8.5.1
Customer Advances	252	1	25,200,443	OR	Situs	25,200,443	8.5.1
Customer Advances	252	1	(495,357)	WA	Situs	-	8.5.1
Customer Advances	252	1	(1,512,441)	ID	Situs	-	8.5.1
Customer Advances	252	1	(29,662,878)	UT	Situs	-	8.5.1
Customer Advances	252	1	(1,159,470)	WYP	Situs	-	8.5.1
Customer Advances	252	1	7,898,702	SG	26.884%	2,123,500	8.5.1
			-			27,323,942	

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 2025
Customer Advances for Construction

END OF PERIOD BASIS:

Account	Booked Allocation	Correct Allocation	Adjustment	Ref.
252CA	-	(268,999)	**(268,999)**	**Page 8.5**
252OR	(30,377,839)	(5,177,396)	**25,200,443**	**Page 8.5**
252WA	(56,154)	(551,511)	**(495,357)**	**Page 8.5**
252IDU	(428,223)	(1,940,664)	**(1,512,441)**	**Page 8.5**
252UT	(335,035)	(29,997,914)	**(29,662,878)**	**Page 8.5**
252WYP	-	(1,159,470)	**(1,159,470)**	**Page 8.5**
252SG	(65,682,312)	(57,783,610)	**7,898,702**	**Page 8.5**
Total	**(96,879,563)**	**(96,879,563)**	**-**	

PacifiCorp
Oregon General Rate Case - December 2025
Regulatory Assets & Liabilities Amortization

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Revenues:							
FERC OATT Deferral Refund	456	3	(4,075,388)	OR	Situs	(4,075,388)	8.6.4
Adjustment to Expense:							
Oregon Distribution System Plan	592	3	855,753	OR	Situs	855,753	8.6.6
Adjustment to Rate Base:							
Elec. Plant Acq. Acc. Amort.	115	3	(75,351)	SG	26.884%	(20,258)	8.6.1
Adjustment to Tax:							
Schedule M Adjustment	SCHMAT	3	855,753	OR	Situs	855,753	8.6.6
Deferred Income Tax Expense	41110	3	(210,401)	OR	Situs	(210,401)	8.6.6

Description of Adjustment:

This adjustment removes from results the amortization of deferred expenses from the Post-2017 FERC OATT Revenue Deferral balance approved in the Company's prior general rate case, Docket UE 374 as the balance is fully amortized as of December 2023.

This adjustment also adds in the proposed amortizations of deferrals including Oregon Distribution System Plan deferral. The Company is proposing a three year amortization for this balance, beginning the effective date of this general rate case, January 1, 2025.

Finally, this adjustment also walks forward Electric Plant Acquisition in the base period (12 months ended June 2023) to pro forma period levels (12 months ending December 2025).

PacifiCorp
Oregon General Rate Case - December 2025
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	144,704,699	(142,051,177)
Base Period Amount (below)	75,351	144,704,699	(141,975,825)
Pro Forma Adjustment	**-**	**-**	**(75,351)**
			Ref. 8.6

Year		**Gross Acquisition**	**Beg Balance Accumulated Amortization**	**Amortization**	**End Balance Accumulated Amortization**	**13 Month Avg Bal Gross Acq**	**13 Month Avg Bal Acc Amort**
	Opening Balance	144,704,699			(141,938,150)		
2022	July	144,704,699	(141,938,150)	(6,279)	(141,944,429)		
	August	144,704,699	(141,944,429)	(6,279)	(141,950,708)		
	September	144,704,699	(141,950,708)	(6,279)	(141,956,988)		
	October	144,704,699	(141,956,988)	(6,279)	(141,963,267)		
	November	144,704,699	(141,963,267)	(6,279)	(141,969,546)		
	December	144,704,699	(141,969,546)	(6,279)	(141,975,825)		
2023	January	144,704,699	(141,975,825)	(6,279)	(141,982,105)		
	February	144,704,699	(141,982,105)	(6,279)	(141,988,384)		
	March	144,704,699	(141,988,384)	(6,279)	(141,994,663)		
	April	144,704,699	(141,994,663)	(6,279)	(142,000,943)		
	May	144,704,699	(142,000,943)	(6,279)	(142,007,222)		
	June	144,704,699	(142,007,222)	(6,279)	(142,013,501)	144,704,699	(141,975,825)
			Base Period Amort =	(75,351)			
2023	July	144,704,699	(142,013,501)	(6,279)	(142,019,780)		
	August	144,704,699	(142,019,780)	(6,279)	(142,026,060)		
	September	144,704,699	(142,026,060)	(6,279)	(142,032,339)		
	October	144,704,699	(142,032,339)	(6,279)	(142,038,618)		
	November	144,704,699	(142,038,618)	(6,279)	(142,044,897)		
	December	144,704,699	(142,044,897)	(6,279)	(142,051,177)		
2024	January	144,704,699	(142,051,177)	(6,279)	(142,057,456)		
	February	144,704,699	(142,057,456)	(6,279)	(142,063,735)		
	March	144,704,699	(142,063,735)	(6,279)	(142,070,015)		
	April	144,704,699	(142,070,015)	(6,279)	(142,076,294)		
	May	144,704,699	(142,076,294)	(6,279)	(142,082,573)		
	June	144,704,699	(142,082,573)	(6,279)	(142,088,852)	144,704,699	(142,051,177)
			Pro Forma Amort =	(75,351)			

PacifiCorp
Oregon General Rate Case - December 2025
Regulatory Assets & Liabilities Amortization
Electric Plant Acquisition Adjustment
GL Account 140800 - Actuals for 12 Months Ended June 2023

Year	Month	Addition / Amortization	Accumulated Amount
2022	6	-	156,468,483
2022	7	-	156,468,483
2022	8	-	156,468,483
2022	9	-	156,468,483
2022	10	-	156,468,483
2022	11	-	156,468,483
2022	12	-	156,468,483
2023	1	-	156,468,483
2023	2	-	156,468,483
2023	3	-	156,468,483
2023	4	-	156,468,483
2023	5	-	156,468,483
2023	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 2022

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 2023

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 2025
Regulatory Assets & Liabilities Amortization
Accumulated Amortization
GL Account 145800 - Actuals for 12 Months Ended June 2023

Year	Month	Amort.	Accumulated Amount
2022	6	(31,416)	(144,137,327)
2022	7	(31,416)	(144,168,742)
2022	8	(31,416)	(144,200,158)
2022	9	(31,416)	(144,231,573)
2022	10	(31,416)	(144,262,989)
2022	11	(31,416)	(144,294,404)
2022	12	(31,416)	(144,325,820)
2023	1	(31,416)	(144,357,236)
2023	2	(31,416)	(144,388,651)
2023	3	(31,416)	(144,420,067)
2023	4	(31,416)	(144,451,482)
2023	5	(31,416)	(144,482,898)
2023	6	(31,416)	**(144,514,313)**

System-allocated amount	(142,013,501)	**Ref. Tab B-15 & 8.6.1**
Utah-situs amount	(2,500,812)	**Ref. Tab B-15**
	(144,514,313)	

GL Account Balance
Account Number 145800
Calendar year 2022

Period	Debit	Credit	Balance	Cumulative balance
Balance Car...				142,419,616.06-
1		423,599.57	423,599.57-	142,843,215.63-
2		423,599.58	423,599.58-	143,266,815.21-
3		423,599.57	423,599.57-	143,690,414.78-
4		384,080.63	384,080.63-	144,074,495.41-
5		31,415.56	31,415.56-	144,105,910.97-
6		31,415.57	31,415.57-	144,137,326.54-
7		31,415.57	31,415.57-	144,168,742.11-
8		31,415.56	31,415.56-	144,200,157.67-
9		31,415.57	31,415.57-	144,231,573.24-
10		31,415.57	31,415.57-	144,262,988.81-
11		31,415.57	31,415.57-	144,294,404.38-
12		31,415.57	31,415.57-	144,325,819.95-

Calendar year 2023

Period	Debit	Credit	Balance	Cumulative balance
Balance Car...				144,325,819.95-
1		31,415.56	31,415.56-	144,357,235.51-
2		31,415.58	31,415.58-	144,388,651.09-
3		31,415.56	31,415.56-	144,420,066.65-
4		31,415.58	31,415.58-	144,451,482.23-
5		31,415.56	31,415.56-	144,482,897.79-
6		31,415.57	31,415.57-	144,514,313.36-
7		31,415.57	31,415.57-	144,545,728.93-
8		31,415.56	31,415.56-	144,577,144.49-
9				144,577,144.49-
10				144,577,144.49-
11				144,577,144.49-
12				144,577,144.49-

PacifiCorp
Oregon General Rate Case - December 2025
Regulatory Assets & Liabilities Amortization
FERC OATT Revenues Deferral (Post 2017)

	Amortization
Base Period Amount (below)	4,075,388
Pro Forma Amount (below)	-
Adjustment:	**(4,075,388)**
	Ref. 8.6

		Opening Bal.	Accrual	Amortization	Interest[1,2]	Ending Bal.
2022	June	(5,994,203)	-	-		(5,994,203)
	July	(5,994,203)	-	339,616	(12,765)	(5,667,352)
	August	(5,667,352)	-	339,616	(12,049)	(5,339,785)
	September	(5,339,785)	-	339,616	(11,331)	(5,011,500)
	October	(5,011,500)	-	339,616	(10,611)	(4,682,496)
	November	(4,682,496)	-	339,616	(9,890)	(4,352,771)
	December	(4,352,771)	-	339,616	(9,168)	(4,022,323)
2023	January	(4,022,323)	-	339,616	(8,443)	(3,691,150)
	February	(3,691,150)	-	339,616	(7,718)	(3,359,252)
	March	(3,359,252)	-	339,616	(6,990)	(3,026,627)
	April	(3,026,627)	-	339,616	(6,261)	(2,693,272)
	May	(2,693,272)	-	339,616	(5,531)	(2,359,187)
	June	(2,359,187)	-	339,616	(4,798)	(2,024,370)
			Base Period Amort =	**4,075,388**		
2023	July	(2,024,370)	-	339,616	(4,065)	(1,688,819)
	August	(1,688,819)	-	339,616	(3,329)	(1,352,532)
	September	(1,352,532)	-	339,616	(2,592)	(1,015,509)
	October	(1,015,509)	-	339,616	(1,853)	(677,747)
	November	(677,747)	-	339,616	(1,113)	(339,244)
	December	(339,244)	-	339,616	(372)	0
2024	January	-	-	-	-	-
	February	-	-	-	-	-
	March	-	-	-	-	-
	April	-	-	-	-	-
	May	-	-	-	-	-
	June	-	-	-	-	-
	July	-	-	-	-	-
	August	-	-	-	-	-
	September	-	-	-	-	-
	October	-	-	-	-	-
	November	-	-	-	-	-
	December	-	-	-	-	-
2025	January	-	-	-	-	-
	February	-	-	-	-	-
	March	-	-	-	-	-
	April	-	-	-	-	-
	May	-	-	-	-	-
	June	-	-	-	-	-
	July	-	-	-	-	-
	August	-	-	-	-	-
	September	-	-	-	-	-
	October	-	-	-	-	-
	November	-	-	-	-	-
	December	-	-	-	-	-
			Pro Forma Amort =	**-**		**-**

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 2025
Regulatory Assets & Liabilities Amortization
FERC OATT Revenues Deferral (Post 2017)
GL Account 288232 - Actuals for 12 Months Ended June 2023

Year	Month	Accrual	Adjustments	Amortization	Interest	Accumulated Amount
2022	6	-	-	-	-	(5,994,203)
2022	7	-	-	339,616	(12,765)	(5,667,352)
2022	8	-	-	339,616	(12,049)	(5,339,785)
2022	9	-	-	339,616	(11,331)	(5,011,500)
2022	10	-	-	339,616	(10,611)	(4,682,496)
2022	11	-	-	339,616	(9,890)	(4,352,771)
2022	12	-	-	339,616	(9,168)	(4,022,323)
2023	1	-	-	339,616	(8,443)	(3,691,150)
2023	2	-	-	339,616	(7,718)	(3,359,252)
2023	3	-	-	339,616	(6,990)	(3,026,627)
2023	4	-	-	339,616	(6,261)	(2,693,272)
2023	5	-	-	339,616	(5,531)	(2,359,187)
2023	6	-	-	339,616	(4,798)	**(2,024,370)**
						Ref 8.6.4

GL Account Balance
Account Number 288232
Calendar year 2022

Period	Debit	Credit	Balance	Cumulative balance
Balance Car...				7,940,350.30-
1	339,615.69	17,030.44	322,585.25	7,617,765.05-
2	339,615.69	16,323.44	323,292.25	7,294,472.80-
3	339,615.69	15,614.89	324,000.80	6,970,472.00-
4	339,615.69	14,904.79	324,710.90	6,645,761.10-
5	339,615.69	14,193.13	325,422.56	6,320,338.54-
6	339,615.69	13,479.91	326,135.78	5,994,202.76-
7	339,615.69	12,765.13	326,850.56	5,667,352.20-
8	339,615.69	12,048.78	327,566.91	5,339,785.29-
9	339,615.69	11,330.87	328,284.82	5,011,500.47-
10	339,615.69	10,611.38	329,004.31	4,682,496.16-
11	339,615.69	9,890.31	329,725.38	4,352,770.78-
12	339,615.69	9,167.66	330,448.03	4,022,322.75-

Calendar year 2023

Period	Debit	Credit	Balance	Cumulative balance
Balance Car...				4,022,322.75-
1	339,615.69	8,443.43	331,172.26	3,691,150.49-
2	339,615.69	7,717.61	331,898.08	3,359,252.41-
3	339,615.69	6,990.20	332,625.49	3,026,626.92-
4	339,615.69	6,261.20	333,354.49	2,693,272.43-
5	339,615.69	5,530.59	334,085.10	2,359,187.33-
6	339,615.69	4,798.39	334,817.30	2,024,370.03-
7	339,615.69	4,064.58	335,551.11	1,688,818.92-
8	339,615.69	3,329.17	336,286.52	1,352,532.40-
9	339,615.69	2,592.14	337,023.55	1,015,508.85-
10	339,615.69	1,853.49	337,762.20	677,746.65-
11	339,615.69	1,113.23	338,502.46	339,244.19-
12	339,615.69	371.50	339,244.19	

PacifiCorp
Oregon General Rate Case - December 2025
Regulatory Assets & Liabilities Amortization
Oregon Distribution System Plan

	Amortization
Base Period Amount (below)	-
Pro Forma Amount (below)	(855,753)
Adjustment:	**(855,753)**
	Ref. 8.6

Year	Month	Opening Bal.	Accrual	Amortization	Interest[1,2]	Ending Bal.	SCHMAT	41110
2022	June	-	-	-	-	-		
	July	-	215,103	-	640	215,743		
	August	215,743	186,304	-	1,837	403,885		
	September	403,885	55,781	-	2,568	462,234		
	October	462,234	90,783	-	3,019	556,036		
	November	556,036	26,700	-	3,386	586,123		
	December	586,123	403,735	-	4,687	994,544		
2023	January	994,544	-	-	5,892	1,000,436		
	February	1,000,436	152,469	-	6,378	1,159,283		
	March	1,159,283	107,115	-	7,185	1,273,583		
	April	1,273,583	100,739	-	7,843	1,382,165		
	May	1,382,165	61,186	-	8,369	1,451,721		
	June	1,451,721	34,939	-	8,704	1,495,363		
			Base Period Amort =	**-**				
	July	1,495,363	73,824	-	9,077	1,578,265		
	August	1,578,265	107,081	-	9,667	1,695,013		
	September	1,695,013	58,557	-	10,215	1,763,785		
	October	1,763,785	74,398	-	10,669	1,848,852		
	November	1,848,852	110,625	-	11,281	1,970,758		
	December	1,970,758	225,224	-	12,342	2,208,324		
2024	January	2,208,324	-	-	13,082	2,221,406		
	February	2,221,406	-	-	13,159	2,234,565		
	March	2,234,565	-	-	13,237	2,247,802		
	April	2,247,802	-	-	13,316	2,261,118		
	May	2,261,118	-	-	13,395	2,274,513		
	June	2,274,513	-	-	13,474	2,287,987		
	July	2,287,987	-	-	13,554	2,301,541		
	August	2,301,541	-	-	13,634	2,315,175		
	September	2,315,175	-	-	13,715	2,328,890		
	October	2,328,890	-	-	13,796	2,342,686		
	November	2,342,686	-	-	13,878	2,356,564		
	December	2,356,564	-	-	13,960	2,370,524	-	-
2025	January	2,370,524	-	(71,313)	10,507	2,309,718	71,313	(17,533)
	February	2,309,718	-	(71,313)	10,233	2,248,639	71,313	(17,533)
	March	2,248,639	-	(71,313)	9,958	2,187,284	71,313	(17,533)
	April	2,187,284	-	(71,313)	9,682	2,125,654	71,313	(17,533)
	May	2,125,654	-	(71,313)	9,405	2,063,746	71,313	(17,533)
	June	2,063,746	-	(71,313)	9,126	2,001,560	71,313	(17,533)
	July	2,001,560	-	(71,313)	8,847	1,939,093	71,313	(17,533)
	August	1,939,093	-	(71,313)	8,565	1,876,346	71,313	(17,533)
	September	1,876,346	-	(71,313)	8,283	1,813,316	71,313	(17,533)
	October	1,813,316	-	(71,313)	7,999	1,750,003	71,313	(17,533)
	November	1,750,003	-	(71,313)	7,715	1,686,405	71,313	(17,533)
	December	1,686,405	-	(71,313)	7,428	1,622,520	71,313	(17,533)
			Pro Forma Amort =	**(855,753)**			**855,753**	**(210,401)**
							Ref 8.6	**Ref 8.6**

Note:
1. Interest rate in deferral period per approved WACC from UE-374 prior to 1/1/2023 and from UE-399 effective 1/1/2023.

	UE-374	UE-399
WACC	7.14%	7.11%

2. Interest accrual at Modified Blended Treasury Rate as of date of the Commission's approval of the amortization (i.e. Dec 2024).

	2024	
MBTR	5.400%	Ref UM-1147

PacifiCorp
Oregon General Rate Case - December 2025
Regulatory Assets & Liabilities Amortization
Oregon Distribution System Plan
GL Account 187353 - Actuals for 12 Months Ended June 2023

Year	Month	Accrual	Amortization	Interest	Accumulated Amount
2022	6				-
2022	7	215,103	-	640	215,743
2022	8	186,304	-	1,837	403,885
2022	9	55,781	-	2,568	462,234
2022	10	90,783	-	3,019	556,036
2022	11	26,700	-	3,386	586,123
2022	12	403,735	-	4,687	994,544
2023	1	-	-	5,892	1,000,436
2023	2	152,469	-	6,378	1,159,283
2023	3	107,115	-	7,185	1,273,583
2023	4	100,739	-	7,843	1,382,165
2023	5	61,186	-	8,369	1,451,721
2023	6	34,939	-	8,704	**1,495,363**
					Ref 8.6.6

GL Account Balance
Account Number 187353

Calendar year 2022

Period	Debit	Credit	Balance	Cumulative balance
Balance Car...				
1				
2				
3				
4				
5				
6				
7	215,743.04		215,743.04	215,743.04
8	188,141.55		188,141.55	403,884.59
9	58,349.42		58,349.42	462,234.01
10	93,802.10		93,802.10	556,036.11
11	30,086.42		30,086.42	586,122.53
12	408,421.57		408,421.57	994,544.10

Calendar year 2023

Period	Debit	Credit	Balance	Cumulative balance
Balance Car...				994,544.10
1	5,891.85		5,891.85	1,000,435.95
2	158,846.93		158,846.93	1,159,282.88
3	114,300.39		114,300.39	1,273,583.27
4	108,582.04		108,582.04	1,382,165.31
5	69,555.60		69,555.60	1,451,720.91
6	43,642.47		43,642.47	1,495,363.38
7	82,901.84		82,901.84	1,578,265.22
8	116,747.74		116,747.74	1,695,012.96
9	68,771.76		68,771.76	1,763,784.72
10	85,067.61		85,067.61	1,848,852.33
11	121,905.43		121,905.43	1,970,757.76
12	237,565.91		237,565.91	2,208,323.67

PacifiCorp
Oregon General Rate Case - December 2025
Plant Held for Future Use

	ACCOUNT	TYPE	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Remove PHFU	105	1	(2,112,145)	SG	26.884%	(567,832)	
Remove PHFU	105	1	-	CA	Situs	-	
Remove PHFU	105	1	(6,893,577)	OR	Situs	(6,893,577)	
Remove PHFU	105	1	(5,168,253)	UT	Situs	-	
Remove PHFU	105	1	(601)	WYP	Situs	-	
			(14,174,575)			(7,461,409)	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 2025
Plant Held for Future Use

Primary Account		Secondary Account		Alloc	Total
1050000	Plant Held for Future Use	3501000	LAND OWNED IN FEE	SG	1,357,583
1050000	Plant Held for Future Use	3502000	LAND RIGHTS	SG	754,562
1050000	Plant Held for Future Use	3601000	LAND OWNED IN FEE	CA	-
1050000	Plant Held for Future Use	3601000	LAND OWNED IN FEE	OR	3,912,456
1050000	Plant Held for Future Use	3601000	LAND OWNED IN FEE	UT	5,168,253
1050000	Plant Held for Future Use	3601000	LAND OWNED IN FEE	WYP	601
1050000	Plant Held for Future Use	3891000	LAND OWNED IN FEE	OR	2,981,121
Total					**14,174,575**
					Ref. 8.7

PacifiCorp
Oregon General Rate Case - December 2025
Pension and Other Post-retirement Plan Balances Removal

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Net Prepaid Balance	128	1	(104,951,393)	SO	27.425%	(28,783,408)	8.8.1
Net Prepaid Balance	182M	1	(224,418,608)	SO	27.425%	(61,547,849)	8.8.1
Net Prepaid Balance	182M	1	(4,965,457)	WYP	Situs	-	8.8.1
Net Prepaid Balance	2283	1	0	SO	27.425%	0	8.8.1
			(334,335,458)			(90,331,257)	
Adjustment to Tax:							
ADIT Balances	190	1	(8,317,989)	SO	27.425%	(2,281,247)	8.8.1
ADIT Balances	283	1	88,539,434	SO	27.425%	24,282,352	8.8.1
ADIT Balances	283	1	1,220,837	WYP	Situs	-	8.8.1
			81,442,282			22,001,105	

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 2025
Pension and Other Post-retirement Plan Balances Removal

FERC Pension Account	Factor	June 2023 End of Period Allocation	Ref
128	SO	104,951,393	**8.8**
182M	SO	224,418,608	**8.8**
182M	WY	4,965,457	**8.8**
2283	SO	(0)	**8.8**
		334,335,458	

FERC Tax Account	Factor	June 2023 End of Period Allocation	Ref
190	SO	8,317,989	**8.8**
283	SO	(88,539,434)	**8.8**
283	WY	(1,220,837)	**8.8**
		(81,442,282)	

PacifiCorp
Oregon General Rate Case - December 2025
Remove Rolling Hills

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Other Plant	341	1	(3,532,745)	SG	26.884%	(949,749)	
Other Plant	343	1	(170,635,863)	SG	26.884%	(45,874,013)	
Other Plant	344	1	(7,930,325)	SG	26.884%	(2,132,001)	
Other Plant	345	1	(12,443,422)	SG	26.884%	(3,345,309)	
Other Plant	346	1	(659,497)	SG	26.884%	(177,300)	
			(195,201,853)			(52,478,373)	8.9.1
Adjustment to Depreciation Reserve:							
Other Plant	108OP	1	(1,561,970)	SG	26.884%	(419,923)	8.9.1
Adjustment to O&M Expense:							
Administrative & General	929	1	(280,729)	SO	27.425%	(76,991)	8.9.1
Misc. Oth. Power Supply	549	1	(44,874)	SG	26.884%	(12,064)	8.9.1
Misc. Oth. Power Supply	553	1	(1,112,621)	SG	26.884%	(299,119)	8.9.1
Adjustment to Tax:							
Schedule M Adjustment	SCHMDT	1	(7,462,581)	TAXDEPR	26.295%	(1,962,286)	
Deferred Tax Expense	41010	1	(1,834,795)	TAXDEPR	26.295%	(482,459)	
ADIT Balance	282	1	46,465,867	SG	26.884%	12,491,957	

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 2023. 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 Case - December 2025
Remove Rolling Hills

Rate Base Amounts	FERC Account	EOP 12 ME Jun 2023	Ref.
Capital			
Other Plant	341	3,532,745	
Other Plant	343	170,635,863	
Other Plant	344	7,930,325	
Other Plant	345	12,443,422	
Other Plant	346	659,497	
		195,201,853	8.9
Depreciation Reserve			
Other Plant	108OP	1,561,970	8.9

Expense Amounts	FERC Account	12 ME Jun 2023	Ref.
Operation & Maintenance Expense			
Administrative & General	929	280,729	8.9
Misc. Oth. Power Supply	549	44,874	8.9
Misc. Oth. Power Supply	553	1,112,621	8.9

PacifiCorp
Oregon General Rate Case - December 2025
Deer Creek Mine Adjustment

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Remove base period expense							
Closure cost amortization	506	1	(6,538,963)	SG	26.884%	(1,757,945)	8.10.1
Add pro forma expense							
UMWA Pension Withdrawal Liability Pymt	926	1	2,967,013	SG	26.884%	797,657	8.10.2
Deer Creek Recovery Royalties	506	3	5,261,096	SE	26.339%	1,385,726	8.10.3
Adjustment to Rate Base:							
Remove base period regulatory assets							
Regulatory Asset	182M	1	1,193,243	OR	Situs	1,193,243	8.10.1
Regulatory Asset	182M	1	(75,268,509)	SE	26.339%	(19,825,062)	8.10.1
Regulatory Asset	182M	1	(8,323,073)	SO	27.425%	(2,282,642)	8.10.1
Add proforma period regulatory assets							
Regulatory Asset	182M	3	13,152,740	SE	26.339%	3,464,316	8.10.3
Adjustment to Tax:							
Remove Base Period Tax							
Schedule M Addition	SCHMAT	1	(5,520,488)	SE	26.339%	(1,454,048)	
Schedule M Addition	SCHMAT	1	(929,514)	SO	27.425%	(254,924)	
Schedule M Deduction	SCHMDT	1	(503,723)	SE	26.339%	(132,676)	
Schedule M Deduction	SCHMDT	1	(3,685,708)	OR	Situs	(3,685,708)	
Def Income Tax Expense	41110	1	1,357,300	SE	26.339%	357,501	
Def Income Tax Expense	41110	1	228,536	SO	27.425%	62,677	
Def Income Tax Expense	41010	1	(123,848)	SE	26.339%	(32,620)	
Def Income Tax Expense	41010	1	(906,190)	OR	Situs	(906,190)	
Accum Def Income Tax Balance	283	1	(13,436,660)	SE	26.339%	(3,539,098)	
Accum Def Income Tax Balance	283	1	48,001,425	SE	26.339%	12,643,152	
Accum Def Income Tax Balance	190	1	(28,303,872)	SE	26.339%	(7,454,991)	
Accum Def Income Tax Balance	283	1	162,133	SO	27.425%	44,466	
Accum Def Income Tax Balance	283	1	(628,890)	OR	Situs	(628,890)	

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.

The Company is including through this adjustment the request to begin amortization of recovery royalties. In docket UE 374, Order 20-473 found that the Company had not demonstrated that preliminary forecasts at that time was sufficiently supported to be included in rates. However, the Company was allowed to continue deferring those costs as approved under docket UM 1712 and seek recovery in a future proceeding. At present, the Company is expecting that payment of royalty obligations will commence in 2024. Accordingly, the Company is including a request to begin amortization of royalty obligations, with rates effective 1/1/2025.

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-375.

PacifiCorp
Oregon General Rate Case - December 2025
Deer Creek Mine Adjustment
Base Period Balances

EXPENSE ACCOUNTS

	Amort
Closure Costs Amortization & Royal Recovery in Unadj. Results	**6,538,963**
	Ref. 8.10

Recovery of Deer Creek closure costs in Oregon is included in a separate tariff rider. Thus, system amounts in unadjusted results should be.

RATE BASE ACCOUNTS

	EOP June 2023 Balance	Booked Allocation	
Unrecovered Plant	(1,662,000)	SE	
Unrecovered Plant	752,316	OR	
Closure Costs	76,930,508	SE	
UMWA PBOP Savings	(1,945,559)	OR	
UMWA PBOP	8,323,073	SO	
Total	**82,398,339**		
Summary by Allocation Factor			
	(1,193,243)	OR	**Ref. 8.10**
	75,268,509	SE	**Ref. 8.10**
	8,323,073	SO	**Ref. 8.10**
	82,398,339		

Oregon's share of Deer Creek mine is being recovered through a separate tariff rider. All balances are removed from rate base as the balances include carrying charges.

PacifiCorp
Oregon General Rate Case - December 2025
Deer Creek Mine Adjustment
UMWA Pension Withdrawal Liability Payment

Year	Posting period	Account Number	FERC Account	FERC Location	Description	In transaction currency
2022	7	278200	2340000	1	UMWA Pension Withdrawal Liability Payment	247,251
2022	8	278200	2340000	1	UMWA Pension Withdrawal Liability Payment	247,251
2022	9	278200	2340000	1	UMWA Pension Withdrawal Liability Payment	247,251
2022	10	278200	2340000	1	UMWA Pension Withdrawal Liability Payment	247,251
2022	11	278200	2340000	1	UMWA Pension Withdrawal Liability Payment	247,251
2022	12	278200	2340000	1	UMWA Pension Withdrawal Liability Payment	247,251
2023	1	278200	2340000	1	UMWA Pension Withdrawal Liability Payment	247,251
2023	2	278200	2340000	1	UMWA Pension Withdrawal Liability Payment	247,251
2023	3	278200	2340000	1	UMWA Pension Withdrawal Liability Payment	247,251
2023	4	278200	2340000	1	UMWA Pension Withdrawal Liability Payment	247,251
2023	5	278200	2340000	1	UMWA Pension Withdrawal Liability Payment	247,251
2023	6	278200	2340000	1	UMWA Pension Withdrawal Liability Payment	247,251
Total						**2,967,013**

PacifiCorp
Oregon General Rate Case - December 2025
Deer Creek Mine Adjustment
Recovery Royalties - Closure Costs

Recovery royalties, which are part of the Deer Creek mine closure costs, had been estimated but not spent in the Company's prior rate cases since UE 374. Payment discussions have commenced, and the Company is anticipating payment to occur in 2024. Accordingly, the Company is seeking to begin amortization of this amount in this rate case. The Company will continue to monitor progress on payment discussions, and modify amounts reflected in this filing throughout the pendency of the case. The Company is proposing three year amortization of these costs starting January 2025.

Estimated Recovery Royalties 15,783,288

Date	Beg Bal	Amortization	End Bal	
Jun-23			15,783,288	
Jul-23	15,783,288		15,783,288	
Aug-23	15,783,288		15,783,288	
Sep-23	15,783,288		15,783,288	
Oct-23	15,783,288		15,783,288	
Nov-23	15,783,288		15,783,288	
Dec-23	15,783,288		15,783,288	
Jan-24	15,783,288		15,783,288	
Feb-24	15,783,288		15,783,288	
Mar-24	15,783,288		15,783,288	
Apr-24	15,783,288		15,783,288	
May-24	15,783,288		15,783,288	
Jun-24	15,783,288		15,783,288	
Jul-24	15,783,288		15,783,288	
Aug-24	15,783,288		15,783,288	
Sep-24	15,783,288		15,783,288	
Oct-24	15,783,288		15,783,288	
Nov-24	15,783,288		15,783,288	
Dec-24	15,783,288		15,783,288	
Jan-25	15,783,288	(438,425)	15,344,864	
Feb-25	15,344,864	(438,425)	14,906,439	
Mar-25	14,906,439	(438,425)	14,468,014	
Apr-25	14,468,014	(438,425)	14,029,590	
May-25	14,029,590	(438,425)	13,591,165	
Jun-25	13,591,165	(438,425)	13,152,740	
Jul-25	13,152,740	(438,425)	12,714,316	
Aug-25	12,714,316	(438,425)	12,275,891	
Sep-25	12,275,891	(438,425)	11,837,466	
Oct-25	11,837,466	(438,425)	11,399,042	
Nov-25	11,399,042	(438,425)	10,960,617	**13 Mo. Avg.**
Dec-25	10,960,617	(438,425)	10,522,192	**13,152,740**
	Amort exp. 12 ME Dec-25	**(5,261,096)**		**Ref. 8.10**
		Ref. 8.10		

PacifiCorp
Oregon General Rate Case - December 2025
Emissions Control Investment Adjustment

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF
Adjustment to Rate Base:							
Hunter Clean Air Disallowance	312	1	(3,641,553)	SG	26.884%	(979,001)	8.11.1
Adjustment to Expense:							
Hunter Clean Air Disallowance	403SP	1	(513,605)	SG	26.884%	(138,078)	8.11.1
Adjustment to Return:							
JB U3 & U4 Return Disallowance	930	1	(1,349,991)	OR	Situs	(1,349,991)	8.11.2
JB U3 & U4 Return Disallowance	930	3	246,859	OR	Situs	246,859	8.11.2
			(1,103,132)			(1,103,132)	
Adjustment to Tax:							
Schedule M Adjustment	SCHMAT	1	(513,605)	SG	26.884%	(138,078)	
Schedule M Adjustment	SCHMDT	1	(128,808)	SG	26.884%	(34,629)	
Deferred Income Tax Expense	41110	1	126,278	SG	26.884%	33,949	
Deferred Income Tax Expense	41010	1	(31,670)	SG	26.884%	(8,514)	
Accumulated Def Inc Tax Balance	282	1	328,655	SG	26.884%	88,356	

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 2025
Emissions Control Investment Adjustment
Hunter Clean Air Equipment Summary

Year End Balance - December 2024		
EPIS Balance	81,171,892	
Steam Plant Reserve	(44,756,366)	
Net Book Value	36,415,526	
NBV Ordered 10% Disallowance	3,641,553	Ref 8.11
Year End Balance - December 2024		
Gross Plant	81,171,892	
Depreciation Rate[1]	6.327%	
Depreciation Expense	5,136,053	
Depr Ordered 10% Disallowance	513,605	Ref 8.11

[1.] *Actual composite steam depreciation rate for June 2023.*

PacifiCorp
Oregon General Rate Case - December 2025
Emissions Control Investment Adjustment
Jim Bridger Unit 3 & 4 SCR Return Disallowance

Restating Adjustment

	Total Co.	OR Allocated
Net Book Value - Year End June 2023	118,448,589	31,843,905
Pre-Tax Rate of Return	9.42%	9.42%
Return on Rate Base Rate of Return	11,157,149	2,999,505
Return - Cost of Long-Term Debt	5.18%	5.18%
Return on Rate Base Cost of Debt	6,135,637	1,649,514
Approx. Revenue Requirement Reduction	(5,021,512)	**(1,349,991)**
		Ref 8.11
System Generation Factor (SG)	26.884%	

Pro Forma Adjustment

	Total Co.	OR Allocated
Net Book Value - Year End December 2024	96,789,135	26,020,943
Pre-Tax Rate of Return	9.42%	9.42%
Return on Rate Base Rate of Return	9,116,958	2,451,017
Return - Cost of Long-Term Debt	5.18%	5.18%
Return on Rate Base Cost of Debt	5,013,677	1,347,885
Approx. Revenue Requirement Reduction	(4,103,281)	(1,103,132)
Pro Forma Adj. to Revenue Requirement Red.		**246,859**
		Ref 8.11
System Generation Factor (SG)	26.884%	

PacifiCorp
Oregon General Rate Case - December 2025
Emissions Control Investment Adjustment
Summary of Variables
Capital Structure and Costs

	Capital Structure	Embedded Cost	Weighted Cost	Tax Net-to-Gross Bump-up	Pre-Tax Revenue Requirement
Debt	49.99%	5.18%	2.59%		2.59%
Preferred	0.01%	6.75%	0.00%	132.60%	0.00%
Common	50.00%	10.30%	5.15%	132.60%	6.83%
Total	100.00%		7.74%		9.42%

Merged Effective Tax Rate	24.587%
Pre-Tax Bump-up Factor	132.60%

2020 Protocol Allocation Factors

Forecast 2025 SG Factor	26.884%

PacifiCorp
Oregon Generation Rate Case - December 2025
Transmission Project Adjustment

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Transmission	352	3	(230,619)	SG	26.884%	(62,000)	8.12.1
Distribution	361	3	(120,000)	OR	Situs	(120,000)	8.12.2
			(350,619)			(182,000)	
Adjustment to Reserve:							
Transmission	108TP	3	25,066	SG	26.884%	6,739	8.12.1
Distribution	108364	3	29,361	OR	Situs	29,361	8.12.2
			54,428			36,100	
Adjustment to Tax:							
ADIT - Transmission	282	3	5,040	OR	Situs	5,040	
ADIT - Distribution	282	3	8,485	OR	Situs	8,485	
			13,525			13,525	

Description of Adjustment:

Rate base disallowances for transmission projects as discussed on Order No. 20-473, Docket No. UE 374.

PacifiCorp
Oregon Generation Rate Case - December 2025
Transmission Project Adjustment

Wallula-to-McNary Project

In-Service Date	Jan-19	
Depreciation Composite Rate	1.875%	UE-374, effective 1/1/2021
Depreciation Composite Rate	1.724%	UE-399, effective 1/1/2023

		*	Gross Plant	Depreciation Expense	Depreciation Reserve	Net Book Value
2022	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
2023	January		62,000	89	(4,690)	57,310
	February		62,000	89	(4,780)	57,220
	March		62,000	89	(4,869)	57,131
	April		62,000	89	(4,958)	57,042
	May		62,000	89	(5,047)	56,953
	June		62,000	89	(5,136)	56,864
	July		62,000	89	(5,225)	56,775
	August		62,000	89	(5,314)	56,686
	September		62,000	89	(5,403)	56,597
	October		62,000	89	(5,492)	56,508
	November		62,000	89	(5,581)	56,419
	December		62,000	89	(5,670)	56,330
2024	January		62,000	89	(5,759)	56,241
	February		62,000	89	(5,848)	56,152
	March		62,000	89	(5,937)	56,063
	April		62,000	89	(6,026)	55,974
	May		62,000	89	(6,115)	55,885
	June		62,000	89	(6,204)	55,796
	July		62,000	89	(6,294)	55,706
	August		62,000	89	(6,383)	55,617
	September		62,000	89	(6,472)	55,528
	October		62,000	89	(6,561)	55,439
	November		62,000	89	(6,650)	55,350
	December		**62,000**	89	**(6,739)**	55,261
			Ref. 8.12		**Ref. 8.12**	

* Oregon's allocated amount

PacifiCorp
Oregon Generation Rate Case - December 2025
Transmission Project Adjustment

Threemile Canyon Project

In-Service Date	Apr-15	
Depreciation Composite Rate	2.585%	UE-374, effective 1/1/2021
Depreciation Composite Rate	2.271%	UE-399, effective 1/1/2023

		Gross Plant	Depreciation Expense	Depreciation Reserve	Net Book Value
2022	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
2023	January	120,000	227	(24,137)	95,863
	February	120,000	227	(24,364)	95,636
	March	120,000	227	(24,592)	95,408
	April	120,000	227	(24,819)	95,181
	May	120,000	227	(25,046)	94,954
	June	120,000	227	(25,273)	94,727
	July	120,000	227	(25,500)	94,500
	August	120,000	227	(25,727)	94,273
	September	120,000	227	(25,954)	94,046
	October	120,000	227	(26,181)	93,819
	November	120,000	227	(26,409)	93,591
	December	120,000	227	(26,636)	93,364
2024	January	120,000	227	(26,863)	93,137
	February	120,000	227	(27,090)	92,910
	March	120,000	227	(27,317)	92,683
	April	120,000	227	(27,544)	92,456
	May	120,000	227	(27,771)	92,229
	June	120,000	227	(27,999)	92,001
	July	120,000	227	(28,226)	91,774
	August	120,000	227	(28,453)	91,547
	September	120,000	227	(28,680)	91,320
	October	120,000	227	(28,907)	91,093
	November	120,000	227	(29,134)	90,866
	December	**120,000**	227	**(29,361)**	90,639
		Ref. 8.12		**Ref. 8.12**	

PacifiCorp
Oregon General Rate Case - December 2025
Cholla Unit 4 Retirement

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense							
Remove Safe Harbor Reserve Reversal	920	1	702,610	OR	Situs	702,610	8.13.1
Remove Nonunion Severance Reserve Reversal	931	1	29,534	OR	Situs	29,534	8.13.1
Pro Forma Safe Harbor Amort. Expense	407	3	4,914	OR	Situs	4,914	8.13.2
Pro Forma Nonunion Severance Amort. Exp.	407	3	23,308	OR	Situs	23,308	8.13.3
Adjustment to Rate Base:							
Remove Base Period Nonunion Severance	182M	1	(2,423,666)	SG	26.884%	(651,582)	8.13.1
Remove Base Period Safe Harbor Lease	182M	1	(101,879)	SG	26.884%	(27,389)	8.13.1
Add Dec. 2025 Cholla Nonunion Severance	182M	3	70,205	OR	Situs	70,205	8.13.3
Add Dec. 2025 Safe Harbor Lease Payment	182M	3	4,918	OR	Situs	4,918	8.13.2
Adjustment to Tax:							
Safe Harbor Lease Reg Asset Amort - Sch M	SCHMAT	3	9,837	SG	26.884%	2,645	8.13.2
Safe Harbor Lease Reg Asset Amort - DITB	41110	3	(2,419)	SG	26.884%	(650)	8.13.2
Safe Harbor Lease Reg Asset Amort - ADIT	283	3	(1,196)	SG	26.884%	(321)	8.13.2
Nonunion Severance Reg Asset Amort. - Sch M	SCHMAT	3	140,410	SG	26.884%	37,748	8.13.3
Nonunion Severance Reg Asset Amort - DITE	41110	3	(34,522)	SG	26.884%	(9,281)	8.13.3
Nonunion Severance Reg Asset Amort - ADIT	283	3	(40,268)	SG	26.884%	(10,826)	8.13.3

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 a portion of closure cost. Subsequently, as part of the settlement outcome adopted in the December 2023 Oregon General Rate Case, the Company was authorized to begin amortization of the remaining unrecovered closure costs over a three-year amortization period. This adjustment removes per books regulatory asset balances from base period results, then adds back the pro forma balance for unrecovered closure costs and authorized amortizations through December 2025.

PacifiCorp
Oregon General Rate Case - December 2025
Cholla Unit 4 Retirement
Historical Period Book Balances

	FERC account			EOP June 2023
Reg Asset-Cholla U4-Nonunion Severance	182M	SG	**$**	**2,423,666**
Reg Asset-Cholla U4-Safe Harbor Lease	182M	SG	**$**	**101,879**
				Ref 8.13

	FERC account			12 ME June 2023
Nonunion Severance Amort - Reserve Reversal	920	OR	**$**	**(702,610)**
Safe Harbor Lease Amort - Reserve Reversal	931	OR	**$**	**(29,534)**

PacifiCorp
Oregon General Rate Case - December 2025
Cholla Unit 4 Retirement
Treatment of Cholla Unrecovered Closure Items

	Total Company	Oregon Allocated	
	UE-399 Approved	**UE-399 Approved**	**Dec-25 13 MA Bal.**
Safe Harbor Lease Payment	113,495	29,511	**4,918**
			Ref. 8.13

	Oregon Allocated		
	June-23 13 MA Bal.	**Dec-25 13 MA Bal.**	**Adjustment**
Nonunion Severance Amortization	(4,922)	(9,837)	**(4,914)**
			Ref. 8.13

UE-399 Approved SG Allocation Factor 26.002%

	OR Alloc. Safe Harbor Lease Pmt	Amortization Total	End Bal		Schedule M	41110	Acc. 286920 283 ADIT	
Dec-22			29,511	Above			(7,256)	
Jan-23	29,511	(820)	28,691		820	(202)	(7,054)	
Feb-23	28,691	(820)	27,871		820	(202)	(6,852)	
Mar-23	27,871	(820)	27,051		820	(202)	(6,650)	
Apr-23	27,051	(820)	26,232		820	(202)	(6,448)	
May-23	26,232	(820)	25,412		820	(202)	(6,246)	
Jun-23	25,412	(820)	24,592		820	(202)	(6,044)	
Jul-23	24,592	(820)	23,773		820	(202)	(5,842)	
Aug-23	23,773	(820)	22,953		820	(202)	(5,640)	
Sep-23	22,953	(820)	22,133		820	(202)	(5,438)	
Oct-23	22,133	(820)	21,313		820	(202)	(5,236)	
Nov-23	21,313	(820)	20,494		820	(202)	(5,034)	
Dec-23	20,494	(820)	19,674		820	(202)	(4,832)	
Jan-24	19,674	(820)	18,854		820	(202)	(4,630)	
Feb-24	18,854	(820)	18,034		820	(202)	(4,428)	
Mar-24	18,034	(820)	17,215		820	(202)	(4,226)	
Apr-24	17,215	(820)	16,395		820	(202)	(4,024)	
May-24	16,395	(820)	15,575		820	(202)	(3,822)	
Jun-24	15,575	(820)	14,755		820	(202)	(3,620)	
Jul-24	14,755	(820)	13,936		820	(202)	(3,418)	
Aug-24	13,936	(820)	13,116		820	(202)	(3,216)	
Sep-24	13,116	(820)	12,296		820	(202)	(3,014)	
Oct-24	12,296	(820)	11,476		820	(202)	(2,812)	
Nov-24	11,476	(820)	10,657		820	(202)	(2,610)	
Dec-24	10,657	(820)	9,837		820	(202)	(2,408)	
Jan-25	9,837	(820)	9,017		820	(202)	(2,206)	
Feb-25	9,017	(820)	8,197		820	(202)	(2,004)	
Mar-25	8,197	(820)	7,378		820	(202)	(1,802)	
Apr-25	7,378	(820)	6,558		820	(202)	(1,600)	
May-25	6,558	(820)	5,738		820	(202)	(1,398)	
Jun-25	5,738	(820)	4,918		820	(202)	(1,196)	
Jul-25	4,918	(820)	4,099		820	(202)	(994)	
Aug-25	4,099	(820)	3,279		820	(202)	(792)	
Sep-25	3,279	(820)	2,459		820	(202)	(590)	
Oct-25	2,459	(820)	1,639		820	(202)	(388)	
Nov-25	1,639	(820)	820		820	(202)	(186)	
Dec-25	820	(820)	(0)	**13 MA Bal.**	820	(207)	21	**13MA Bal.**
		(9,837)		**4,918**	**9,837**	**(2,419)**		**(1,196)**
		Ref. 8.13		**Above**	**Ref. 8.13**	**Ref. 8.13**		**Ref. 8.13**

PacifiCorp
Oregon General Rate Case - December 2025
Cholla Unit 4 Retirement
Treatment of Cholla Unrecovered Closure Items

	Total Company	Oregon Allocated	
	UE-399 Approved	**UE-399 Approved**	**Dec-25 13 MA Bal.**
Nonunion Severance Balance	2,700,000	702,048	**70,205**
			Ref. 8.13

	Oregon Allocated		
	June-23 13 MA Bal.	**Dec-25 13 MA Bal.**	**Adjustment**
Nonunion Severance Amortization	(117,102)	(140,410)	**(23,308)**
			Ref. 8.13

UE-399 Approved SG Allocation Factor 26.002%

Oregon-Allocated

	Beg Bal	True-Up	Amortization	End Bal		Schedule M	41110	Acc. 286920 283 ADIT	
Dec-22	702,048			702,048	Above			(172,610)	
Jan-23	702,048		(19,501)	682,546		19,501	(4,795)	(167,815)	
Feb-23	682,546		(19,501)	663,045		19,501	(4,795)	(163,020)	
Mar-23	663,045		(19,501)	643,544		19,501	(4,795)	(158,225)	
Apr-23	643,544		(19,501)	624,042		19,501	(4,795)	(153,430)	
May-23	624,042		(19,501)	604,541		19,501	(4,795)	(148,635)	
Jun-23	604,541		(19,501)	585,040		19,501	(4,795)	(143,840)	
Jul-23	585,040		(19,501)	565,538		19,501	(4,795)	(139,045)	
Aug-23	565,538		(19,501)	546,037		19,501	(4,795)	(134,250)	
Sep-23	546,037		(19,501)	526,536		19,501	(4,795)	(129,455)	
Oct-23	526,536		(19,501)	507,034		19,501	(4,795)	(124,660)	
Nov-23	507,034		(19,501)	487,533		19,501	(4,795)	(119,865)	
Dec-23	487,533	(93,606)	(19,501)	374,425		19,501	(4,795)	(115,070)	
Jan-24	374,425		(19,501)	354,924		19,501	(4,795)	(110,275)	
Feb-24	354,924		(19,501)	335,423		19,501	(4,795)	(105,480)	
Mar-24	335,423		(19,501)	315,921		19,501	(4,795)	(100,685)	
Apr-24	315,921		(19,501)	296,420		19,501	(4,795)	(95,890)	
May-24	296,420		(19,501)	276,919		19,501	(4,795)	(91,095)	
Jun-24	276,919		(19,501)	257,417		19,501	(4,795)	(86,300)	
Jul-24	257,417		(19,501)	237,916		19,501	(4,795)	(81,505)	
Aug-24	237,916		(19,501)	218,415		19,501	(4,795)	(76,710)	
Sep-24	218,415		(19,501)	198,913		19,501	(4,795)	(71,915)	
Oct-24	198,913		(19,501)	179,412		19,501	(4,795)	(67,120)	
Nov-24	179,412		(19,501)	159,911		19,501	(4,795)	(62,325)	
Dec-24	159,911		(19,501)	140,410		19,501	(4,795)	(57,530)	
Jan-25	140,410		(11,701)	128,709		11,701	(2,877)	(54,653)	
Feb-25	128,709		(11,701)	117,008		11,701	(2,877)	(51,776)	
Mar-25	117,008		(11,701)	105,307		11,701	(2,877)	(48,899)	
Apr-25	105,307		(11,701)	93,606		11,701	(2,877)	(46,022)	
May-25	93,606		(11,701)	81,906		11,701	(2,877)	(43,145)	
Jun-25	81,906		(11,701)	70,205		11,701	(2,877)	(40,268)	
Jul-25	70,205		(11,701)	58,504		11,701	(2,877)	(37,391)	
Aug-25	58,504		(11,701)	46,803		11,701	(2,877)	(34,514)	
Sep-25	46,803		(11,701)	35,102		11,701	(2,877)	(31,637)	
Oct-25	35,102		(11,701)	23,402		11,701	(2,877)	(28,760)	
Nov-25	23,402		(11,701)	11,701		11,701	(2,877)	(25,883)	
Dec-25	11,701		(11,701)	(0)	**13 MA Bal.**	11,701	(2,875)	(23,008)	**13MA Bal.**
	Amort exp. 12 ME Dec-25		**(140,410)**		**70,205**	**140,410**	**(34,522)**		**(40,268)**
			Ref. 8.13		**Above**	**Ref. 8.13**	**Ref. 8.13**		**Ref. 8.13**

PacifiCorp
Oregon General Rate Case - December 2025
Miscellaneous Rate Base

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
1 - Fuel Stock - Pro Forma	151	3	3,274,511	SE	26.339%	862,477	8.14.1
2 - Fuel Stock - Working Capital Deposit	25316	3	2,002,231	SE	26.339%	527,370	8.14.1
2 - Fuel Stock - Working Capital Deposit	25317	3	(1,386,738)	SE	26.339%	(365,255)	8.14.1
3 - Prepaid Overhauls	186M	3	10,315,186	SG	26.884%	2,773,151	8.14.1

Description of Adjustment:

1 - Fuel stock levels for the 13 month average year ending December 2025 are projected to be lower than the year ended June 2023 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 2025.

PacifiCorp
Oregon General Rate Case - December 2025
Miscellaneous Rate Base

1 - Coal Fuel Stock Balances by Plant	**Account**	**Factor**	Actuals **Jun-2023 EOP Balance**	Pro Forma **Dec-2025 13 Mth. Avg. Balance**	**Adj. to 13 Mth. Avg. Balance**	
Jim Bridger	151	SE	(36,657,668)	(62,572,307)	(25,914,639)	
Cholla	151	SE	-	-	-	
Colstrip	151	SE	(2,092,828)	(2,044,088)	48,740	
Craig	151	SE	(7,582,296)	(9,871,296)	(2,289,000)	
Hayden	151	SE	(2,644,532)	(2,868,649)	(224,117)	
Hunter	151	SE	(24,158,107)	(17,006,919)	7,151,188	
Huntington	151	SE	(22,463,774)	(21,148,562)	1,315,212	
Dave Johnston	151	SE	(15,026,113)	(15,502,897)	(476,784)	
Naughton	151	SE	(21,629,537)	(2,663,320)	18,966,217	
Rock Garden	151	SE	(4,697,694)	-	4,697,694	
Total			(136,952,549)	(133,678,038)	**3,274,511**	**Ref. 8.14**

1 - Working Capital Deposits	**Account**	**Factor**	Actuals **Jun-2023 EOP Balance**	Pro Forma **Dec-2025 13 Mth. Avg. Balance**	**Adj. to 13 Mth. Avg. Balance**	
UAMPS Working Capital Deposit	25316	SE	(3,180,000)	(1,177,769)	**2,002,231**	**Ref. 8.14**
DPEC Working Capital Deposit	25317	SE	(2,592,034)	(3,978,772)	**(1,386,738)**	**Ref. 8.14**

2 - Overhaul Prepayments by Plant	**Account**	**Factor**	Actuals **Jun-2023 EOP Balance**	Pro Forma **Dec-2025 13 Mth. Avg. Balance**	**Adj. to 13 Mth. Avg. Balance**	
Lake Side 1	186M	SG	(24,823,813)	(7,771,815)	17,051,998	
Chehalis	186M	SG	(10,640,887)	(24,732,549)	(14,091,662)	
Currant Creek	186M	SG	(10,552,675)	(23,133,374)	(12,580,699)	
Lake Side 2	186M	SG	(33,049,760)	(11,678,664)	21,371,095	
Chehalis O&M	186M	SG	(1,640,642)	(2,392,025)	(751,383)	
Currant Creek O&M	186M	SG	(420,580)	(1,104,744)	(684,163)	
Total			(81,128,357)	(70,813,171)	**10,315,186**	**Ref. 8.14**

PacifiCorp
Oregon General Rate Case - December 2025
Carbon Plant Closure

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Excess decommissioning costs amort.	407	3	(1,615,751)	OR	Situs	(1,615,751)	8.15.1
Adjustment to Rate Base:							
Remove M&S Obsolete Inventory	182M	1	(3,446,305)	SG	26.884%	(926,510)	B-16
Remove M&S Obsolete Inventory	182M	1	448,718	OR	Situs	448,718	B-16
Excess decommissioning reserves	254	3	(807,875)	OR	Situs	(807,875)	8.15.1
Adjustment to Tax:							
Schedule M - Excess Decommissioning	SCHMAT	3	(179,487)	OR	Situs	(179,487)	8.15.2
Deferred Income Tax Expense	41110	3	44,130	OR	Situs	44,130	8.15.2
Accumulated Def Inc Tax Balance	190	3	(684,147)	OR	Situs	(684,147)	8.15.2
Accumulated Def Inc Tax Balance	283	1	155,252	SG	26.884%	41,738	

Description of Adjustment:

The Carbon Plant was retired April, 2015 and fully recovered as of December 2020. 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 and also reflected in the Company's most recent general rate case Docket No. UE 399.

PacifiCorp
Oregon General Rate Case - December 2025
Carbon Plant Closure
Closing Costs in Pro Forma Period

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.

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-21	(6,597,649)	134,646	(6,463,003)	
Jan-22	(6,463,003)	134,646	(6,328,357)	
Feb-22	(6,328,357)	134,646	(6,193,711)	
Mar-22	(6,193,711)	134,646	(6,059,065)	
Apr-22	(6,059,065)	134,646	(5,924,419)	
May-22	(5,924,419)	134,646	(5,789,773)	
Jun-22	(5,789,773)	134,646	(5,655,128)	
Jul-22	(5,655,128)	134,646	(5,520,482)	
Aug-22	(5,520,482)	134,646	(5,385,836)	
Sep-22	(5,385,836)	134,646	(5,251,190)	
Oct-22	(5,251,190)	134,646	(5,116,544)	
Nov-22	(5,116,544)	134,646	(4,981,898)	
Dec-22	(4,981,898)	134,646	(4,847,252)	
Jan-23	(4,847,252)	134,646	(4,712,606)	
Feb-23	(4,712,606)	134,646	(4,577,960)	
Mar-23	(4,577,960)	134,646	(4,443,315)	
Apr-23	(4,443,315)	134,646	(4,308,669)	
May-23	(4,308,669)	134,646	(4,174,023)	
Jun-23	(4,174,023)	134,646	(4,039,377)	
Jul-23	(4,039,377)	134,646	(3,904,731)	
Aug-23	(3,904,731)	134,646	(3,770,085)	
Sep-23	(3,770,085)	134,646	(3,635,439)	
Oct-23	(3,635,439)	134,646	(3,500,793)	
Nov-23	(3,500,793)	134,646	(3,366,147)	
Dec-23	(3,366,147)	134,646	(3,231,501)	
Jan-24	(3,231,501)	134,646	(3,096,856)	
Feb-24	(3,096,856)	134,646	(2,962,210)	
Mar-24	(2,962,210)	134,646	(2,827,564)	
Apr-24	(2,827,564)	134,646	(2,692,918)	
May-24	(2,692,918)	134,646	(2,558,272)	
Jun-24	(2,558,272)	134,646	(2,423,626)	
Jul-24	(2,423,626)	134,646	(2,288,980)	
Aug-24	(2,288,980)	134,646	(2,154,334)	
Sep-24	(2,154,334)	134,646	(2,019,688)	
Oct-24	(2,019,688)	134,646	(1,885,043)	
Nov-24	(1,885,043)	134,646	(1,750,397)	
Dec-24	(1,750,397)	134,646	(1,615,751)	
Jan-25	(1,615,751)	134,646	(1,481,105)	
Feb-25	(1,481,105)	134,646	(1,346,459)	
Mar-25	(1,346,459)	134,646	(1,211,813)	
Apr-25	(1,211,813)	134,646	(1,077,167)	
May-25	(1,077,167)	134,646	(942,521)	
Jun-25	(942,521)	134,646	(807,875)	
Jul-25	(807,875)	134,646	(673,229)	
Aug-25	(673,229)	134,646	(538,584)	
Sep-25	(538,584)	134,646	(403,938)	
Oct-25	(403,938)	134,646	(269,292)	
Nov-25	(269,292)	134,646	(134,646)	13MA Bal.
Dec-25	(134,646)	134,646	-	**(807,875)**
Amort exp. 12 ME Dec. 2025		**1,615,751**		**Ref 8.15**
		Ref. 8.15		

June 2023 Net Amort. Exp	1,615,751	Above
December 2025 Net Amort. Exp	1,615,751	Above
Total Adjustment	-	

PacifiCorp
Oregon General Rate Case - December 2025
Carbon Plant Closure
Closing Costs in Pro Forma Period

Tax Impacts - Closure Costs

Date	SCHMAT	41110	ADIT
Dec-21	134,646	(33,105)	1,589,033
Jan-22	134,646	(33,105)	1,555,928
Feb-22	134,646	(33,105)	1,522,823
Mar-22	134,646	(33,105)	1,489,718
Apr-22	134,646	(33,105)	1,456,613
May-22	134,646	(33,105)	1,423,509
Jun-22	134,646	(33,105)	1,390,404
Jul-22	134,646	(33,105)	1,357,299
Aug-22	134,646	(33,105)	1,324,194
Sep-22	134,646	(33,105)	1,291,089
Oct-22	134,646	(33,105)	1,257,984
Nov-22	134,646	(33,105)	1,224,880
Dec-22	134,646	(33,105)	1,191,775
Jan-23	134,646	(33,105)	1,158,670
Feb-23	134,646	(33,105)	1,125,565
Mar-23	134,646	(33,105)	1,092,460
Apr-23	134,646	(33,105)	1,059,355
May-23	134,646	(33,105)	1,026,250
Jun-23	134,646	(33,105)	993,146
Jul-23	134,646	(33,105)	960,041
Aug-23	134,646	(33,105)	926,936
Sep-23	134,646	(33,105)	893,831
Oct-23	134,646	(33,105)	860,726
Nov-23	134,646	(33,105)	827,621
Dec-23	134,646	(33,105)	794,516
Jan-24	134,646	(33,105)	761,412
Feb-24	134,646	(33,105)	728,307
Mar-24	134,646	(33,105)	695,202
Apr-24	134,646	(33,105)	662,097
May-24	134,646	(33,105)	628,992
Jun-24	134,646	(33,105)	595,887
Jul-24	134,646	(33,105)	562,783
Aug-24	134,646	(33,105)	529,678
Sep-24	134,646	(33,105)	496,573
Oct-24	134,646	(33,105)	463,468
Nov-24	134,646	(33,105)	430,363
Dec-24	134,646	(33,105)	397,258
Jan-25	134,646	(33,105)	364,153
Feb-25	134,646	(33,105)	331,049
Mar-25	134,646	(33,105)	297,944
Apr-25	134,646	(33,105)	264,839
May-25	134,646	(33,105)	231,734
Jun-25	134,646	(33,105)	198,629
Jul-25	134,646	(33,105)	165,524
Aug-25	134,646	(33,105)	132,420
Sep-25	134,646	(33,105)	99,315
Oct-25	134,646	(33,105)	66,210
Nov-25	134,646	(33,105)	33,105
Dec-25	134,646	(33,105)	0

	SCHMAT	41110	ADIT 13MA Bal.
	1,615,751	**(397,258)**	**198,629**
Less: Amt in PowerTax	1,795,238	(441,388)	882,776
	(179,487)	**44,130**	**(684,147)**
	Ref. 8.15	**Ref. 8.15**	**Ref. 8.15**

PacifiCorp
Oregon General Rate Case - December 2025
Removal of Wildfire Mitigation Capital Rate Base

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
Transmission Plant	352	1	(35,333)	SG	26.884%	(9,499)	
Transmission Plant	353	1	(2,578,568)	SG	26.884%	(693,226)	
Transmission Plant	355	1	(39,638)	SG	26.884%	(10,656)	
Transmission Plant	356	1	(11,772)	SG	26.884%	(3,165)	
Distribution Plant	361	1	(17,796)	OR	Situs	(17,796)	
Distribution Plant	362	1	(1,104,576)	OR	Situs	(1,104,576)	
Distribution Plant	364	1	(220,260)	OR	Situs	(220,260)	
Distribution Plant	365	1	(11,617,251)	OR	Situs	(11,617,251)	
Distribution Plant	366	1	(7,993)	OR	Situs	(7,993)	
Distribution Plant	368	1	(13,616)	OR	Situs	(13,616)	
Distribution Plant	369	1	(5,644)	OR	Situs	(5,644)	
Distribution Plant	373	1	(167)	OR	Situs	(167)	
General Plant	392	1	(210,533)	OR	Situs	(210,533)	
General Plant	393	1	(158,850)	OR	Situs	(158,850)	
General Plant	395	1	(272,474)	OR	Situs	(272,474)	
General Plant	395	1	(88,628)	SG	26.884%	(23,827)	
General Plant	396	1	(61,806)	OR	Situs	(61,806)	
General Plant	397	1	(4,265,058)	SO	27.425%	(1,169,712)	
General Plant	397	1	(136,662)	OR	Situs	(136,662)	
General Plant	397	1	(451,355)	SG	26.884%	(121,343)	
Intangible Plant	303	1	(4,076,230)	SO	27.425%	(1,117,925)	
			(25,374,211)			(16,976,982)	8.16.2
Adjustment to Depreciation Reserve:							
Transmission Depreciation Reserve	108TP	1	91,782	SG	26.884%	24,675	
Distribution Depreciation Reserve	108361	1	77	OR	Situs	77	
Distribution Depreciation Reserve	108362	1	8,181	OR	Situs	8,181	
Distribution Depreciation Reserve	108364	1	8,491	OR	Situs	8,491	
Distribution Depreciation Reserve	108365	1	192,119	OR	Situs	192,119	
Distribution Depreciation Reserve	108366	1	84	OR	Situs	84	
Distribution Depreciation Reserve	108368	1	869	OR	Situs	869	
Distribution Depreciation Reserve	108369	1	193	OR	Situs	193	
Distribution Depreciation Reserve	108373	1	14	OR	Situs	14	
General Depreciation Reserve	108GP	1	67,628	SO	27.425%	18,547	
General Depreciation Reserve	108GP	1	74,432	OR	Situs	74,432	
General Depreciation Reserve	108GP	1	24,121	SG	26.884%	6,485	
Intangible Amortization Reserve	111IP	1	1,007,876	SO	27.425%	276,415	
			1,475,867			610,582	8.16.2

Description of Adjustment:

This adjustment removes the gross plant and accumulated depreciation reserve amounts included in the June 2023 YE base period amounts (September 2019 to June 2023) that are associated with and eligible for recovery in the annual Wildfire Mitigation Plan, Automatic Adjustment Clause filing (WMP_AAC). This treatment is consistent Oregon Commission Advise No. 23-015, dated January 9, 2024.

Tax impacts of this adjustment can be found on Page 8.16.1.

PacifiCorp
Oregon General Rate Case - December 2025
(cont.) Removal of Wildfire Mitigation Capital Rate Base

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Tax:							
Schedule M Additions	SCHMAT	1	(314,812)	OR	Situs	(314,812)	
Schedule M Additions	SCHMAT	1	(64,733)	SG	26.884%	(17,403)	
Schedule M Additions	SCHMAT	1	(563,595)	SO	27.425%	(154,569)	
Schedule M Deductions	SCHMDT	1	(1,024,481)	OR	Situs	(1,024,481)	
Schedule M Deductions	SCHMDT	1	(315,682)	SG	26.884%	(84,868)	
Schedule M Deductions	SCHMDT	1	(1,908,314)	SO	27.425%	(523,364)	
Deferred Tax Expense	41110	1	77,401	OR	Situs	77,401	
Deferred Tax Expense	41110	1	15,916	SG	26.884%	4,279	
Deferred Tax Expense	41110	1	138,569	SO	27.425%	38,003	
Deferred Tax Expense	41010	1	(251,886)	OR	Situs	(251,886)	
Deferred Tax Expense	41010	1	(77,615)	SG	26.884%	(20,866)	
Deferred Tax Expense	41010	1	(469,189)	SO	27.425%	(128,677)	
Accum. Def. Inc. Tax. Bal.	282	1	466,032	OR	Situs	466,032	
Accum. Def. Inc. Tax. Bal.	282	1	238,855	SG	26.884%	64,214	
Accum. Def. Inc. Tax. Bal.	282	1	1,054,182	SO	27.425%	289,114	

Description of Adjustment:

This adjustment removes the gross plant and accumulated depreciation reserve amounts included in the June 2023 YE base period amounts (September 2019 to June 2023) that are associated with and eligible for recovery in the annual Wildfire Mitigation Plan, Automatic Adjustment Clause filing (WMP_AAC). This treatment is consistent Oregon Commission Advise No. 23-015, dated January 9, 2024.

Tax impacts of this adjustment can be found on Page 8.16.1.

PacifiCorp
Oregon General Rate Case - December 2025
Removal of Wildfire Mitigation Capital Rate Base

				EPIS	Reserve	Net Book Value	
Function	**FERC Plant Account**	**Code**	**FERC Plant Account Description**	**Accum. Through June 2023**	**Accum. Through June 2023**	**Year End June 2023**	**Ref**
Transmission	3520000	SG	Structures & Improvements	35,333	(35,720)	(387)	
	3530000	SG	Station Equipment	2,498,594	(53,230)	2,445,364	
	3537000	SG	Station Equipment-Supervisory & Alarm	79,974	(1,746)	78,228	
	3550000	SG	Poles and Fixtures	39,638	(740)	38,898	
	3560000	SG	Overhead Conductors & Devices	11,772	(346)	11,426	
Transmission Total				2,665,311	(91,782)	2,573,529	
Distribution	3610000	OR	Structures & Improvements	17,796	(77)	17,720	
	3620000	OR	Station Equipment	1,021,922	(7,517)	1,014,405	
	3627000	OR	Station Equipment-Supervisory & Alarm	82,654	(664)	81,990	
	3640000	OR	Poles, Towers and Fixtures	220,260	(8,491)	211,769	
	3650000	OR	Overhead Conductors & Devices	11,617,251	(192,119)	11,425,131	
	3660000	OR	Underground Conduit	7,993	(84)	7,909	
	3680000	OR	Line Transformers	13,616	(869)	12,747	
	3691000	OR	Services - Overhead	26	(0)	25	
	3692000	OR	Services - Underground	5,618	(193)	5,425	
	3730000	OR	Street Lighting & Signal Systems	167	(14)	153	
Distribution Total				12,987,303	(210,029)	12,777,274	
General Plant	3920500	OR	1 Ton and Above, Two-Axle Trucks	59,019	(9,839)	49,180	
	3921400	OR	Snowmobiles, Motorcycles (4-Wheeled ATV)	151,515	(22,303)	129,212	
	3930000	OR	Stores Equipment	158,850	(16,114)	142,736	
	3950000	OR	Laboratory Equipment	272,474	(12,439)	260,035	
	3950000	SG	Laboratory Equipment	88,628	(4,046)	84,582	
	3961300	OR	Snowcats, Backhoes, Trenchers, Snowblowr	61,806	(7,659)	54,148	
	3970000	SO	Communication Equipment	4,265,058	(67,628)	4,197,431	
	3970000	OR	Communication Equipment	136,662	(6,078)	130,584	
	3970000	SG	Communication Equipment	451,355	(20,075)	431,280	
General Plant Total				5,645,367	(166,180)	5,479,187	
Intangible	3033420	SO	ADS	824,810	(135,774)	689,036	
	3033430	SO	Technosylva	1,828,399	(456,478)	1,371,922	
	3033440	SO	Situational Awareness	1,168,785	(379,238)	789,547	
	3034900	SO	MISC - Miscellaneous	254,235	(36,386)	217,849	
Intangible Total				4,076,230	(1,007,876)	3,068,354	
			EPIS Total	**25,374,211**	**(1,475,867)**	**23,898,344**	**8.16**

PacifiCorp
Oregon General Rate Case - December 2025
Confidential New Wind Generation Capital Additions

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Rate Base:							
New Wind Capital - Wind	343	3	517,208,412	SG-W	26.884%	139,047,122	8.17.1
Adjustment to Depreciation Expense:							
New Wind Capital - Wind Depr. Expense	403OP	3	21,765,634	SG-W	26.884%	5,851,507	8.17.1
Adjustment to Depreciation Reserve:							
New Wind Capital - Wind Depr. Reserve	108OP	3	(906,901)	SG-W	26.884%	(243,813)	8.17.1
Adjustment to Operations & Maintenance Expense:							
Incremental Wind Repowering O&M	549	3	4,501,511	SG	26.884%	1,210,193	8.17.2

Description of Adjustment:

This adjustment adds into the Test Period certain confidential wind generation capital projects. Included in this adjustment is incremental operations and maintenance expense for these confidential projects and the non-confidential Foote Creek II-IV repowering project. The tax impacts associated with these projects are included in the Power Tax adjustment, Page 7.6.

PacifiCorp
Oregon General Rate Case - December 2025
Confidential New Wind Generation Capital Additions

NEW WIND CAPITAL ADDITIONS

Electric Plant in Service

	Account	Factor	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24
Other Plant Wind	343	SG-W	-	-	-	-	-	-	-	-	-	-	-	-	517,208,412

Depreciation Expense*

	Account	Factor													Annual Depr. Expense
Other Plant Wind	403OP	SG-W	-	-	-	-	-	-	-	-	-	-	-	-	21,765,634

Depreciation Reserve

	Account	Factor	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24
Other Plant Wind	108OP	SG-W	-	-	-	-	-	-	-	-	-	-	-	-	(906,901)

	12 ME Jun 2023	End of Period Dec 2024	Adjustment	
343	-	517,208,412	**517,208,412**	**Ref. 8.17**
403OP	-	21,765,634	**21,765,634**	**Ref. 8.17**
108OP	-	(906,901)	**(906,901)**	**Ref. 8.17**

*Composite Depreciation Rate - Wind 4.208%

PacifiCorp
Oregon General Rate Case - December 2025
Confidential New Wind Generation Capital Additions
CONFIDENTIAL

Note: Please see Confidential Exhibit PAC/1708_CONF for redacted information.

Project	Date	Project Capital Amount	Ref
New Wind			
WBUILD - RMP Rock Creek I 190 MW 2024	Dec-2024	[redacted]	**8.17.3**
Rock River I	Dec-2024		**8.17.3**
		517,208,412	**8.17.1**

Project	2025 O&M	
WBUILD - RMP Rock Creek I 190 MW 2024	2,992,590	
Rock River I	771,773	
Foote Creek II-IV Repower	737,148	
	4,501,511	**8.17**

PacifiCorp
Oregon General Rate Case - December 2025
Wildfire Restoration Costs Deferral Amortization

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Wildfire Restoration Capital	407	3	18,271,016	OR	Situs	18,271,016	8.18.1
Damaged Asset NBV	407	3	609,626	OR	Situs	609,626	8.18.2
Adjustment to Rate Base:							
Damaged Asset NBV	182M	3	(1,878,302)	OR	Situs	(1,878,302)	8.18.2
Adjustment to Tax:							
Damaged Asset - Schedule M	SCHMAT	3	746,424	OR	Situs	746,424	
Damaged Asset - Def. Inc. Tax Exp.	41110	3	(183,520)	OR	Situs	(183,520)	
Damaged Asset - ADIT	283	3	461,811	OR	Situs	461,811	
Wildfire Restoration - Schedule M	SCHMAT	3	18,271,016	OR	Situs	18,271,016	
Wildfire Restoration - Def. Inc. Tax Exp.	41110	3	(4,492,222)	OR	Situs	(4,492,222)	

Description of Adjustment:

This adjustment adds into test period results the amortization deferred revenue requirement associated with damage restoration from the 2020 Labor Day wildfires, net of deferred revenue requirement amounts associated with plant no longer used and useful. (Docket No. UM 2116).

This adjustment proposes/requests to begin amortization of the deferred revenue requirement for the wildfire damage net book value and capital additions over a three year period, starting 1/1/2025.

PacifiCorp
Oregon General Rate Case - December 2025
Wildfire Restoration Costs Deferral Amortization
Restoration Costs Deferral Summary

	Amortization
Base Period Amount (below)	-
Pro Forma Amount (below)	18,271,016
Adjustment:	**18,271,016**
	Ref. 8.18

			Accrual							
		Opening Bal.	**Capital[1]**	**O&M[1]**	**Amortization**	**Interest[2,3]**	**Ending Bal.**	**SCHMAT**	**41110**	**ADIT -190**
2020	September	-	225,956	1,236,820	-	718	1,463,494			
	October		423,667	159,267	-	1,345	584,280			
	November	584,280	423,667	107,431	-	5,056	1,120,434			
	December	1,120,434	423,667	654,107	-	7,924	2,206,133			
2021	January	2,206,133	423,667	99,343	-	14,381	2,743,525			
	February	2,743,525	423,667	11,183	-	17,577	3,195,954			
	March	3,195,954	423,667	(34,900)	-	20,268	3,604,989			
	April	3,604,989	423,667	7,353	-	22,701	4,058,712			
	May	4,058,712	423,667	33,244	-	25,400	4,541,023			
	June	4,541,023	423,667	3,065	-	28,268	4,996,024			
	July	4,996,024	423,667	147	-	30,975	5,450,814			
	August	5,450,814	423,667	-	-	33,680	5,908,161			
	September	5,908,161	945,185	115	-	37,951	6,891,411			
	October	6,891,411	945,185	1,437	-	43,799	7,881,832			
	November	7,881,832	945,185	575	-	49,689	8,877,281			
	December	8,877,281	945,185	(900)	-	55,610	9,877,176			
2022	January	9,877,176	945,185	283	-	61,557	10,884,201			
	February	10,884,201	945,185	397	-	67,546	11,897,329			
	March	11,897,329	945,185	2,193	-	73,572	12,918,279			(3,176,166)
	April	12,918,279	945,185	(577)	-	79,644	13,942,532	-	-	(3,427,994)
	May	13,942,532	945,185	8,495	-	85,736	14,981,947	-	-	(3,683,551)
	June	14,981,947	945,185	6,044	-	91,918	16,025,095	-	-	(3,940,026)
	July	16,025,095	945,185	525	-	98,123	17,068,927	-	-	(4,196,669)
	August	17,068,927	945,185	2,390	-	104,331	18,120,833	-	-	(4,455,297)
	September	18,120,833	961,837	(13)	-	110,637	19,193,294	-	-	(4,718,978)
	October	19,193,294	961,837	970	-	117,016	20,273,117	-	-	(4,984,470)
	November	20,273,117	961,837	(1,910)	-	123,438	21,356,482	-	-	(5,250,833)
	December	21,356,482	961,837	-	-	129,882	22,448,201	-	-	(5,519,249)
2023	January	22,448,201	961,837	58	-	135,830	23,545,926	-	-	(5,789,143)
	February	23,545,926	961,837	70	-	142,333	24,650,166	-	-	(6,060,638)
	March	24,650,166	961,837		-	148,875	25,760,878	-	-	(6,333,724)
	April	25,760,878	961,837		-	155,454	26,878,169	-		(6,608,428)
	May	26,878,169	961,837		-	162,073	28,002,080	-		(6,884,759)
	June	28,002,080	961,837		-	168,731	29,132,648	-		(7,162,728)
	July	29,132,648	961,837		-	175,428	30,269,913	-		(7,442,343)
	August	30,269,913	961,837		-	182,165	31,413,916	-		(7,723,614)
	September	31,413,916	950,908		-	188,910	32,553,734	-		(8,003,856)
	October	32,553,734	950,908		-	195,662	33,700,304	-		(8,285,759)
	November	33,700,304	950,908		-	202,454	34,853,666	-		(8,569,331)
	December	34,853,666	950,908		-	209,287	36,013,860	-		(8,854,584)
2024	January	36,013,860	950,908		-	216,160	37,180,927	-		(9,141,526)
	February	37,180,927	950,908		-	223,073	38,354,908	-		(9,430,168)
	March	38,354,908	950,908		-	230,028	39,535,844	-		(9,720,520)
	April	39,535,844	950,908		-	237,024	40,723,775	-		(10,012,592)
	May	40,723,775	950,908		-	244,061	41,918,744	-		(10,306,394)
	June	41,918,744	950,908		-	251,140	43,120,791	-		(10,601,936)
	July	43,120,791	950,908		-	258,261	44,329,960	-		(10,899,230)
	August	44,329,960	950,908		-	265,424	45,546,291	-		(11,198,284)
	September	45,546,291	926,506		-	272,557	46,745,353	-		(11,493,093)
	October	46,745,353	926,506		-	279,660	47,951,519	-		(11,789,648)
	November	47,951,519	926,506		-	286,805	49,164,829	-		(12,087,960)
	December	49,164,829	926,506		-	293,993	50,385,328	-		(12,388,039)
2025	January	50,385,328			1,522,585	230,160	49,092,903	1,522,585	(374,351.80)	(12,070,276)
	February	49,092,903			1,522,585	224,344	47,794,662	1,522,585	(374,351.80)	(11,751,082)
	March	47,794,662			1,522,585	218,502	46,490,579	1,522,585	(374,351.80)	(11,430,453)
	April	46,490,579			1,522,585	212,633	45,180,628	1,522,585	(374,351.80)	(11,108,380)
	May	45,180,628			1,522,585	206,739	43,864,782	1,522,585	(374,351.80)	(10,784,858)
	June	43,864,782			1,522,585	200,817	42,543,014	1,522,585	(374,351.80)	(10,459,881)
	July	42,543,014			1,522,585	194,869	41,215,299	1,522,585	(374,351.80)	(10,133,441)
	August	41,215,299			1,522,585	188,895	39,881,609	1,522,585	(374,351.80)	(9,805,532)
	September	39,881,609			1,522,585	182,893	38,541,918	1,522,585	(374,351.80)	(9,476,147)
	October	38,541,918			1,522,585	176,864	37,196,197	1,522,585	(374,351.80)	(9,145,280)
	November	37,196,197			1,522,585	170,809	35,844,421	1,522,585	(374,351.80)	(8,812,924)
	December	35,844,421			1,522,585	164,726	34,486,562	1,522,585	(374,351.80)	(8,479,073)
			Pro Forma Amort =		18,271,016			18,271,016	(4,492,222)	

Note:
1. See annual revenue requirement calculation and summary of deferred O&M costs in following supporting pages.
2. Interest rate in deferral period per approved WACC per general rate case order most currently approved prior to deferral application and each subsequent annual renewal application.
3. Interest rate in amortization period per UM-1147, MBT rate, approved January 12, 2024 of 5.400%

PacifiCorp
Oregon General Rate Case - December 2025
Wildfire Restoration Costs Deferral Amortization
Wildfire Damaged Asset NBV

	Amortization	Rate Base		ADIT
Base Period Amount (below)	-	1,878,302	**Ref B-16**	(461,811)
Pro Forma Amount (below)	609,626	-		-
Adjustment:	**609,626**	**(1,878,302)**		**461,811**
	Ref. 8.18	**Ref. 8.18**		**Ref. 8.18**

Year	Month	Opening Bal.	Deferral	Amortization	Interest[1]	Ending Bal.		SCHMAT	41110	ADIT -283
2022	June	-	1,888,682	-		1,888,682				
	July	1,888,682	-	-		1,888,682				
	August	1,888,682	-	-		1,888,682				
	September	1,888,682	(180,088)	-		1,708,594				
	October	1,708,594	-	-		1,708,594				
	November	1,708,594	-	-		1,708,594				
	December	1,708,594	32,910	-		1,741,504				
2023	January	1,741,504	-	-		1,741,504				
	February	1,741,504	-	-		1,741,504				
	March	1,741,504	940	-		1,742,443				
	April	1,742,443	-	-		1,742,443				
	May	1,742,443	-	-		1,742,443				
	June	1,742,443	(80)	-		1,742,364				
			Base Period Amort =	**-**						
2023	July	1,742,364	-	-		1,742,364				
	August	1,742,364	-	-		1,742,364				
	September	1,742,364	1,361	-		1,743,725				
	October	1,743,725	-	-		1,743,725				
	November	1,743,725	-	-		1,743,725				
	December	1,743,725	-	-		1,743,725				
2024	January	1,743,725	-	-		1,743,725				
	February	1,743,725	-	-		1,743,725				
	March	1,743,725	-	-		1,743,725				
	April	1,743,725	-	-		1,743,725				
	May	1,743,725	-	-		1,743,725				
	June	1,743,725	-	-		1,743,725				
	July	1,743,725	-	-		1,743,725				
	August	1,743,725	-	-		1,743,725				
	September	1,743,725	-	-		1,743,725				
	October	1,743,725	-	-		1,743,725				
	November	1,743,725	-	-		1,743,725				
	December	1,743,725	-	-		1,743,725		-	-	(428,723)
2025	January	1,743,725	-	50,802	7,732	1,700,655		50,802	(12,491)	(416,232)
	February	1,700,655	-	50,802	7,539	1,657,391		50,802	(12,491)	(403,742)
	March	1,657,391	-	50,802	7,344	1,613,933		50,802	(12,491)	(391,251)
	April	1,613,933	-	50,802	7,148	1,570,280		50,802	(12,491)	(378,761)
	May	1,570,280	-	50,802	6,952	1,526,429		50,802	(12,491)	(366,270)
	June	1,526,429	-	50,802	6,755	1,482,382		50,802	(12,491)	(353,780)
	July	1,482,382	-	50,802	6,556	1,438,136		50,802	(12,491)	(341,289)
	August	1,438,136	-	50,802	6,357	1,393,691		50,802	(12,491)	(328,799)
	September	1,393,691	-	50,802	6,157	1,349,046		50,802	(12,491)	(316,308)
	October	1,349,046	-	50,802	5,956	1,304,201		50,802	(12,491)	(303,818)
	November	1,304,201	-	50,802	5,755	1,259,153		50,802	(12,491)	(291,327)
	December	1,259,153	-	50,802	5,552	1,213,903		50,802	(12,491)	(278,837)
			Pro Forma Amort =	**609,626**				**609,626**	**(149,886)**	**-**
				13 MA 2025 Balance		**1,480,994**	Base pd.	(136,798)	33,634	(461,811)
						Above	Adj.	746,424	(183,520)	461,811
								Ref 8.18	**Ref 8.18**	**Above**

Note:
1. Wildfire Damaged NBV balance assumed to remain in rate base until new rate case takes effect 1/1/2025. With new base rates effective with this case, this balance will be removed from rate base to accrue interest at the Modified Blended Treasury Rate (MBTR) as approved in UM-1147, on January 12, 2024

PacifiCorp
Oregon General Rate Case - December 2025
Wildfire Restoration Costs Deferral Amortization
Revenue Requirement Summary

		Wildfire Restoration Deferral - Year 1		
		Total Company	Approved Allocation %	Oregon Allocated
Revenue Requirement	**Factor**			
Capital Investment				
Distribution	OR	28,514,695	100.000%	28,514,695
Transmission	SG	64,453,425	26.053%	16,792,052
Depreciation Reserve				
Distribution	OR	(262,121)	100.000%	(262,121)
Transmission	SG	(339,692)	26.053%	(88,500)
Accumulated DIT Balance	OR	(353,158)	100.000%	(353,158)
Accumulated DIT Balance	SG	(773,618)	26.053%	(201,551)
Net Rate Base		91,239,532		44,401,417
Pre-Tax Rate of Return		9.291%		9.291%
Pre-Tax Return on Rate Base		8,477,068		4,125,337
Depreciation				
Distribution	OR	675,561	100.000%	675,561
Transmission	SG	1,086,676	26.053%	283,112
Deferred Income Tax Expense	SG	-	26.053%	-
Annual Rev. Reqt. Before Gross-up		10,239,305		5,084,010
Monthly Rev. Reqt. Before Gross-up				423,667

		Wildfire Restoration Deferral - Year 2		
		Total Company	Approved Allocation %	Oregon Allocated
Revenue Requirement	**Factor**			
Capital Investment				
Distribution	OR	63,388,334	100.000%	63,388,334
Transmission	SG	151,315,884	26.023%	39,376,377
Depreciation Reserve				
Distribution	OR	(1,346,236)	100.000%	(1,346,236)
Transmission	SG	(2,447,813)	26.023%	(636,985)
Accumulated DIT Balance	OR	(1,143,054)	100.000%	(1,143,054)
Accumulated DIT Balance	SG	(2,400,381)	26.023%	(624,642)
Net Rate Base		207,366,735		99,013,793
Pre-Tax Rate of Return		9.291%		9.291%
Pre-Tax Return on Rate Base		19,266,451		9,199,375
Depreciation				
Distribution	OR	1,464,155	100.000%	1,464,155
Transmission	SG	2,608,070	26.023%	678,689
Deferred Income Tax Expense	SG	-	26.023%	-
Annual Rev. Reqt. Before Gross-up		23,338,677		11,342,219
Monthly Rev. Reqt. Before Gross-up				945,185

PacifiCorp
Oregon General Rate Case - December 2025
Wildfire Restoration Costs Deferral Amortization
Revenue Requirement Summary

		Wildfire Restoration Deferral - Year 3		
		Total Company	Approved Allocation %	Oregon Allocated
Revenue Requirement	**Factor**			
Capital Investment				
Distribution	OR	75,898,180	100.000%	75,898,180
Transmission	SG	142,044,704	26.023%	36,963,772
Depreciation Reserve				
Distribution	OR	(3,001,066)	100.000%	(3,001,066)
Transmission	SG	(4,918,336)	26.023%	(1,279,880)
Accumulated DIT Balance	OR	(2,015,497)	100.000%	(2,015,497)
Accumulated DIT Balance	SG	(4,105,194)	26.023%	(1,068,280)
Net Rate Base		203,902,791		105,497,228
Pre-Tax Rate of Return		8.686%		8.686%
Pre-Tax Return on Rate Base		17,711,132		9,163,559
Depreciation				
Distribution	OR	1,740,739	100.000%	1,740,739
Transmission	SG	2,450,744	26.023%	637,748
Deferred Income Tax Expense	SG	-	26.023%	-
Annual Rev. Reqt. Before Gross-up		21,902,615		11,542,047
Monthly Rev. Reqt. Before Gross-up				961,837

		Wildfire Restoration Deferral - Year 4		
		Total Company	Approved Allocation %	Oregon Allocated
Revenue Requirement	**Factor**			
Capital Investment				
Distribution	OR	77,680,070	100.000%	77,680,070
Transmission	SG	142,848,779	26.002%	37,143,198
Depreciation Reserve				
Distribution	OR	(4,770,157)	100.000%	(4,770,157)
Transmission	SG	(7,377,255)	26.002%	(1,918,216)
Accumulated DIT Balance	OR	(2,800,240)	100.000%	(2,800,240)
Accumulated DIT Balance	SG	(5,730,595)	26.002%	(1,490,056)
Net Rate Base		199,850,602		103,844,600
Pre-Tax Rate of Return		8.658%		8.658%
Pre-Tax Return on Rate Base		17,302,143		8,990,386
Depreciation				
Distribution	OR	1,779,813	100.000%	1,779,813
Transmission	SG	2,464,031	26.002%	640,691
Deferred Income Tax Expense	SG	-	26.002%	-
Annual Rev. Reqt. Before Gross-up		21,545,988		11,410,891
Monthly Rev. Reqt. Before Gross-up				950,908

PacifiCorp
Oregon General Rate Case - December 2025
Wildfire Restoration Costs Deferral Amortization
Revenue Requirement Summary

		Wildfire Restoration Deferral - Year 5		
		Total Company	**Approved Allocation %**	**Oregon Allocated**
Revenue Requirement	**Factor**			
Capital Investment				
Distribution	OR	77,713,756	100.000%	77,713,756
Transmission	SG	142,895,852	26.002%	37,155,438
Depreciation Reserve				
Distribution	OR	(6,550,444)	100.000%	(6,550,444)
Transmission	SG	(9,841,884)	26.002%	(2,559,063)
Accumulated DIT Balance	OR	(3,457,249)	100.000%	(3,457,249)
Accumulated DIT Balance	SG	(7,108,932)	26.002%	(1,848,448)
Net Rate Base		193,651,098		100,453,990
Pre-Tax Rate of Return		8.658%		8.658%
Pre-Tax Return on Rate Base		16,765,419		8,696,843
Depreciation				
Distribution	OR	1,780,351	100.000%	1,780,351
Transmission	SG	2,464,726	26.002%	640,872
Deferred Income Tax Expense	SG	-	26.002%	-
Annual Rev. Reqt. Before Gross-up		21,010,496		11,118,066
Monthly Rev. Reqt. Before Gross-up				926,506

PacifiCorp
Oregon General Rate Case - December 2025
Wildfire Restoration Costs Deferral Amortization
Restoration Capital Cost Details

Deferral Year 1

	Gross Plant In Service		Accumulated Depreciation			Depreciation Expense	
	Distribution	Transmission	Distribution	Transmission		Distribution	Transmission
Aug-20	-	-	-	-	Aug-20	-	-
Sep-20	2,776,913	-	(2,925)	-	Sep-20	2,925	-
Oct-20	4,565,309	68,219	(10,660)	(50)	Oct-20	7,734	50
Nov-20	14,424,732	74,050	(30,664)	(153)	Nov-20	20,005	104
Dec-20	36,099,056	70,263,275	(83,887)	(51,440)	Dec-20	53,223	51,286
Jan-21	37,286,876	69,324,408	(153,937)	(151,759)	Jan-21	70,050	100,319
Feb-21	37,564,721	69,524,073	(225,386)	(251,547)	Feb-21	71,449	99,788
Mar-21	37,974,366	69,638,672	(297,492)	(351,561)	Mar-21	72,105	100,014
Apr-21	38,067,509	70,032,834	(370,077)	(451,941)	Apr-21	72,585	100,380
May-21	38,173,064	70,235,868	(442,852)	(552,749)	May-21	72,775	100,809
Jun-21	40,549,906	89,852,182	(517,997)	(667,802)	Jun-21	75,145	115,053
Jul-21	41,308,375	164,101,331	(596,134)	(850,314)	Jul-21	78,137	182,512
Aug-21	41,900,208	164,779,611	(675,561)	(1,086,676)	Aug-21	79,426	236,361
13-mo average	**28,514,695**	**64,453,425**	**(262,121)**	**(339,692)**	**12-mo ending**	**675,561**	**1,086,676**

Deferral Year 2

	Gross Plant In Service		Accumulated Depreciation			Depreciation Expense	
Wind Generation	Distribution	Transmission	Distribution	Transmission		Distribution	Transmission
Aug-21	41,900,208	164,779,611	(675,561)	(1,086,676)	Jul-22	79,426	236,361
Sep-21	43,705,576	165,213,393	(757,275)	(1,323,836)	Aug-22	81,715	237,161
Oct-21	44,796,266	186,889,738	(841,754)	(1,576,887)	Sep-22	84,479	253,051
Nov-21	45,884,548	186,929,980	(928,313)	(1,845,545)	Oct-22	86,559	268,658
Dec-21	71,038,012	140,329,131	(1,039,921)	(2,080,741)	Nov-22	111,608	235,196
Jan-22	71,520,557	140,341,619	(1,176,000)	(2,282,454)	Dec-22	136,079	201,713
Feb-22	71,756,491	140,341,705	(1,312,764)	(2,484,177)	Jan-23	136,764	201,723
Mar-22	72,225,328	140,315,904	(1,450,201)	(2,685,881)	Feb-23	137,437	201,704
Apr-22	72,181,457	140,315,904	(1,588,044)	(2,887,566)	Mar-23	137,843	201,685
May-22	72,273,430	140,315,904	(1,725,933)	(3,089,252)	Apr-23	137,889	201,685
Jun-22	72,213,181	140,376,558	(1,863,852)	(3,290,981)	May-23	137,919	201,729
Jul-22	72,233,859	140,478,525	(2,001,733)	(3,492,827)	Jun-23	137,881	201,846
Aug-22	72,319,433	140,478,525	(2,139,716)	(3,694,746)	Jul-23	137,983	201,919
13-mo average	**63,388,334**	**151,315,884**	**(1,346,236)**	**(2,447,813)**	**12-mo ending**	**1,464,155**	**2,608,070**

Depreciation Rate	*2.528%*	*1.750%*
Depreciation Rate	*2.291%*	*1.725%*

PacifiCorp
Oregon General Rate Case - December 2025
Wildfire Restoration Costs Deferral Amortization
Restoration Capital Cost Details

Deferral Year 3

	Gross Plant In Service		Accumulated Depreciation			Depreciation Expense	
	Distribution	**Transmission**	**Distribution**	**Transmission**		**Distribution**	**Transmission**
Aug-22	72,319,433	140,478,525	(2,139,716)	(3,694,746)	Aug-22	137,983	201,919
Sep-22	72,345,071	140,478,525	(2,277,805)	(3,896,665)	Sep-22	138,089	201,919
Oct-22	73,861,156	142,471,166	(2,417,365)	(4,100,017)	Oct-22	139,560	203,351
Nov-22	75,055,967	142,843,950	(2,559,513)	(4,305,068)	Nov-22	142,148	205,051
Dec-22	76,389,613	141,839,497	(2,704,075)	(4,509,665)	Dec-22	144,562	204,597
Jan-23	76,658,296	141,928,351	(2,850,166)	(4,713,604)	Jan-23	146,091	203,939
Feb-23	76,678,259	142,021,033	(2,996,533)	(4,917,674)	Feb-23	146,367	204,070
Mar-23	76,781,055	142,103,478	(3,143,017)	(5,121,870)	Mar-23	146,484	204,196
Apr-23	77,201,056	142,399,767	(3,290,000)	(5,326,338)	Apr-23	146,983	204,468
May-23	77,273,392	142,366,857	(3,437,452)	(5,530,995)	May-23	147,453	204,657
Jun-23	77,343,830	142,466,854	(3,585,042)	(5,735,700)	Jun-23	147,589	204,705
Jul-23	77,367,947	142,544,664	(3,732,721)	(5,940,533)	Jul-23	147,679	204,833
Aug-23	77,401,262	142,638,492	(3,880,455)	(6,145,490)	Aug-23	147,734	204,956
13-mo average	**75,898,180**	**142,044,704**	**(3,001,066)**	**(4,918,336)**	**12-mo ending**	**1,740,739**	**2,450,744**

Deferral Year 4

	Gross Plant In Service		Accumulated Depreciation			Depreciation Expense	
Wind Generation	**Distribution**	**Transmission**	**Distribution**	**Transmission**		**Distribution**	**Transmission**
Aug-23	77,401,262	142,638,492	(3,880,455)	(6,145,490)	Aug-23	147,734	204,956
Sep-23	77,650,166	142,716,843	(4,028,459)	(6,350,570)	Sep-23	148,004	205,080
Oct-23	77,677,534	142,765,790	(4,176,726)	(6,555,742)	Oct-23	148,267	205,172
Nov-23	77,688,143	142,850,331	(4,325,030)	(6,761,009)	Nov-23	148,304	205,268
Dec-23	77,713,756	142,895,852	(4,473,368)	(6,966,370)	Dec-23	148,338	205,361
Jan-24	77,713,756	142,895,852	(4,621,730)	(7,171,764)	Jan-24	148,363	205,394
Feb-24	77,713,756	142,895,852	(4,770,093)	(7,377,158)	Feb-24	148,363	205,394
Mar-24	77,713,756	142,895,852	(4,918,456)	(7,582,552)	Mar-24	148,363	205,394
Apr-24	77,713,756	142,895,852	(5,066,818)	(7,787,946)	Apr-24	148,363	205,394
May-24	77,713,756	142,895,852	(5,215,181)	(7,993,339)	May-24	148,363	205,394
Jun-24	77,713,756	142,895,852	(5,363,543)	(8,198,733)	Jun-24	148,363	205,394
Jul-24	77,713,756	142,895,852	(5,511,906)	(8,404,127)	Jul-24	148,363	205,394
Aug-24	77,713,756	142,895,852	(5,660,269)	(8,609,521)	Aug-24	148,363	205,394
13-mo average	**77,680,070**	**142,848,779**	**(4,770,157)**	**(7,377,255)**	**12-mo ending**	**1,779,813**	**2,464,031**
					Depreciation Rate	*2.291%*	*1.725%*

PacifiCorp
Oregon General Rate Case - December 2025
Wildfire Restoration Costs Deferral Amortization
Restoration Capital Cost Details

Deferral Year 5

	Gross Plant In Service		Accumulated Depreciation			Depreciation Expense	
	Distribution	Transmission	Distribution	Transmission		Distribution	Transmission
Aug-24	77,713,756	142,895,852	(5,660,269)	(8,609,521)	Aug-22	148,363	205,394
Sep-24	77,713,756	142,895,852	(5,808,631)	(8,814,915)	Sep-22	148,363	205,394
Oct-24	77,713,756	142,895,852	(5,956,994)	(9,020,308)	Oct-22	148,363	205,394
Nov-24	77,713,756	142,895,852	(6,105,356)	(9,225,702)	Nov-22	148,363	205,394
Dec-24	77,713,756	142,895,852	(6,253,719)	(9,431,096)	Dec-22	148,363	205,394
Jan-25	77,713,756	142,895,852	(6,402,082)	(9,636,490)	Jan-23	148,363	205,394
Feb-25	77,713,756	142,895,852	(6,550,444)	(9,841,884)	Feb-23	148,363	205,394
Mar-25	77,713,756	142,895,852	(6,698,807)	(10,047,277)	Mar-23	148,363	205,394
Apr-25	77,713,756	142,895,852	(6,847,169)	(10,252,671)	Apr-23	148,363	205,394
May-25	77,713,756	142,895,852	(6,995,532)	(10,458,065)	May-23	148,363	205,394
Jun-25	77,713,756	142,895,852	(7,143,895)	(10,663,459)	Jun-23	148,363	205,394
Jul-25	77,713,756	142,895,852	(7,292,257)	(10,868,853)	Jul-23	148,363	205,394
Aug-25	77,713,756	142,895,852	(7,440,620)	(11,074,247)	Aug-23	148,363	205,394
13-mo average	**77,713,756**	**142,895,852**	**(6,550,444)**	**(9,841,884)**	**12-mo ending**	**1,780,351**	**2,464,726**
					Depreciation Rate	*2.291%*	*1.725%*

PacifiCorp
Oregon General Rate Case - December 2025
Wildfire Restoration Costs Deferral Amortization
Restoration Capital Cost Details
Tax Balances Summary

Deferral Year 1

	Distribution ADIT	Transmission ADIT	Total ADIT
Aug-20	(12,802)	0	(12,802)
Sep-20	(18,484)	0	(18,484)
Oct-20	(121,126)	(215,930)	(337,056)
Nov-20	(220,751)	(431,846)	(652,597)
Dec-20	(312,209)	(635,178)	(947,387)
Jan-21	(349,821)	(713,959)	(1,063,780)
Feb-21	(387,089)	(792,871)	(1,179,960)
Mar-21	(424,196)	(871,727)	(1,295,923)
Apr-21	(465,143)	(981,555)	(1,446,698)
May-21	(506,043)	(1,091,277)	(1,597,320)
Jun-21	(546,360)	(1,197,497)	(1,743,857)
Jul-21	(591,236)	(1,445,307)	(2,036,543)
Aug-21	(635,796)	(1,679,878)	(2,315,674)
13-mo average	**(353,158)**	**(773,618)**	**(1,126,775)**

Deferral Year 2

	Distribution ADIT	Transmission ADIT	Total ADIT
Aug-21	(635,796)	(1,679,878)	(2,315,674)
Sep-21	(679,793)	(1,914,252)	(2,594,045)
Oct-21	(802,262)	(1,952,437)	(2,754,699)
Nov-21	(924,220)	(1,986,785)	(2,911,005)
Dec-21	(1,040,019)	(2,029,360)	(3,069,379)
Jan-22	(1,108,537)	(2,179,512)	(3,288,049)
Feb-22	(1,176,886)	(2,329,661)	(3,506,547)
Mar-22	(1,245,070)	(2,479,815)	(3,724,885)
Apr-22	(1,313,136)	(2,630,067)	(3,943,203)
May-22	(1,381,190)	(2,780,319)	(4,161,509)
Jun-22	(1,449,237)	(2,930,560)	(4,379,797)
Jul-22	(1,517,606)	(3,080,961)	(4,598,567)
Aug-22	(1,585,951)	(3,231,344)	(4,817,295)
13-mo average	**(1,143,054)**	**(2,400,381)**	**(3,543,435)**

PacifiCorp
Oregon General Rate Case - December 2025
Wildfire Restoration Costs Deferral Amortization
Restoration Capital Cost Details
Tax Balances Summary

Deferral Year 3

	Distribution ADIT	Transmission ADIT	Total ADIT
Aug-22	(1,585,951)	(3,231,344)	(4,817,295)
Sep-22	(1,654,269)	(3,381,727)	(5,035,996)
Oct-22	(1,734,453)	(3,535,784)	(5,270,237)
Nov-22	(1,814,001)	(3,689,423)	(5,503,424)
Dec-22	(1,892,955)	(3,843,174)	(5,736,128)
Jan-23	(1,958,738)	(3,980,247)	(5,938,984)
Feb-23	(2,024,453)	(4,117,288)	(6,141,740)
Mar-23	(2,090,139)	(4,254,298)	(6,344,436)
Apr-23	(2,156,567)	(4,391,800)	(6,548,366)
May-23	(2,222,880)	(4,529,255)	(6,752,134)
Jun-23	(2,289,159)	(4,666,698)	(6,955,856)
Jul-23	(2,355,690)	(4,804,407)	(7,160,096)
Aug-23	(2,422,207)	(4,942,085)	(7,364,291)
13-mo average	**(2,015,497)**	**(4,105,194)**	**(6,120,691)**

Deferral Year 4

	Distribution ADIT	Transmission ADIT	Total ADIT
Aug-23	(2,422,207)	(4,942,085)	(7,364,291)
Sep-23	(2,488,658)	(5,079,733)	(7,568,390)
Oct-23	(2,554,769)	(5,217,525)	(7,772,293)
Nov-23	(2,620,871)	(5,355,293)	(7,976,163)
Dec-23	(2,686,964)	(5,493,037)	(8,180,001)
Jan-24	(2,746,240)	(5,617,086)	(8,363,326)
Feb-24	(2,805,516)	(5,741,135)	(8,546,651)
Mar-24	(2,864,792)	(5,865,184)	(8,729,976)
Apr-24	(2,924,068)	(5,989,233)	(8,913,301)
May-24	(2,983,344)	(6,113,282)	(9,096,626)
Jun-24	(3,042,620)	(6,237,331)	(9,279,951)
Jul-24	(3,101,896)	(6,361,380)	(9,463,276)
Aug-24	(3,161,172)	(6,485,429)	(9,646,601)
13-mo average	**(2,800,240)**	**(5,730,595)**	**(8,530,834)**

PacifiCorp Page 8.18.11
Oregon General Rate Case - December 2025
Wildfire Restoration Costs Deferral Amortization
Restoration Capital Cost Details
Tax Balances Summary

Deferral Year 5

	Distribution ADIT	Transmission ADIT	Total ADIT
Aug-24	(3,161,172)	(6,485,429)	(9,646,601)
Sep-24	(3,220,448)	(6,609,479)	(9,829,926)
Oct-24	(3,279,724)	(6,733,528)	(10,013,252)
Nov-24	(3,338,999)	(6,857,577)	(10,196,577)
Dec-24	(3,398,275)	(6,981,627)	(10,379,902)
Jan-25	(3,445,944)	(7,083,158)	(10,529,102)
Feb-25	(3,489,617)	(7,176,178)	(10,665,795)
Mar-25	(3,528,865)	(7,259,774)	(10,788,639)
Apr-25	(3,563,832)	(7,334,251)	(10,898,083)
May-25	(3,594,374)	(7,399,304)	(10,993,678)
Jun-25	(3,620,635)	(7,455,237)	(11,075,872)
Jul-25	(3,642,471)	(7,501,747)	(11,144,218)
Aug-25	(3,659,883)	(7,538,833)	(11,198,716)
13-mo average	**(3,457,249)**	**(7,108,932)**	**(10,566,182)**

PacifiCorp
Oregon General Rate Case - December 2025
Wildfire Restoration Costs Deferral Amortization
Restoration O&M Costs Summary

	Distribution - OREGON						
	Almeda Fire Damage Repair	Archie Creek Fire Damage Repair	Beachie Creek Fire Damage Repair	Echo Mountain Fire Damage Repair	Slater Fire (Happy Camp) Fire Damage	Two Four Two Fire Damage Repair	Total
Sep-20	315,376	189,081	316,260	163,751	116,792	65,876	1,167,136
Oct-20	21,828	(69,742)	62,436	130,898	(38,582)	35,508	142,346
Nov-20	(60,220)	200,443	(48,242)	(62,854)	70,302	(55,867)	43,562
Dec-20	33,977	415,012	(86,079)	92,698	(5,713)	162,402	612,297
Jan-21	35,018	11,303	5,041	2,719	-	29,086	83,167
Feb-21	100	9,973	300	710	26	-	11,109
Mar-21	(33,085)	(354)	(1,340)	(368)	-	-	(35,148)
Apr-21	2,482	5,111	(253)	13	-	-	7,353
May-21	1,595	328	-	31,322	-	-	33,244
Jun-21	-	3,065	-	-	-	-	3,065
Jul-21	-	147	-	-	-	-	147
Aug-21	-	-	-	-	-	-	-
Sep-21	-	115	-	-	-	-	115
Oct-21	-	1,437	-	-	-	-	1,437
Nov-21	-	-	575	-	-	-	575
Dec-21	-	(900)	-	-	-	-	(900)
Jan-22	-	-	-	-	-	-	-
Feb-22	-	-	-	-	-	-	-
Mar-22	-	268	1,925	-	-	-	2,193
Apr-22	-	-	(600)	-	-	-	(600)
May-22	-	-	-	-	-	-	-
Jun-22	-	-	823	-	-	-	823
	317,071	765,288	250,846	358,890	142,826	237,004	**2,071,925**

	Transmission - System						
	Archie Creek Fire Damage Repair	Slater Fire (Happy Camp) Fire Damage	Echo Mountain Fire Damage Repair	Two Four Two Fire Damage Repair	Total	SG Allocation	Oregon Allocated Total
Sep-20	154,261	-	94,435	18,772	267,469	26.053%	69,684
Oct-20	96,846	-	(51,157)	19,259	64,948	26.053%	16,921
Nov-20	209,247	32,653	5,400	(2,150)	245,149	26.053%	63,869
Dec-20	(70,108)	185,318	76,987	(31,717)	160,480	26.053%	41,810
Jan-21	-	-	33,075	29,086	62,161	26.023%	16,176
Feb-21	285	-	-	-	285	26.023%	74
Mar-21	951	-	-	-	951	26.023%	248
Apr-21	-	-	-	-	-	26.023%	-
May-21	-	-	-	-	-	26.023%	-
Jun-21	-	-	-	-	-	26.023%	-
Jul-21	-	-	-	-	-	26.023%	-
Aug-21	-	-	-	-	-	26.023%	-
Sep-21	-	-	-	-	-	26.023%	-
Oct-21	-	-	-	-	-	26.023%	-
Nov-21	-	-	-	-	-	26.023%	-
Dec-21	-	-	-	-	-	26.023%	-
Jan-22	1,088	-	-	-	1,088	26.023%	283
Feb-22	1,526	-	-	-	1,526	26.023%	397
Mar-22	-	-	-	-	-	26.023%	-
Apr-22	89	-	-	-	89	26.023%	23
May-22	32,643	-	-	-	32,643	26.023%	8,495
Jun-22	20,063	-	-	-	20,063	26.023%	5,221
Jul-22	2,018	-	-	-	2,018	26.023%	525
Aug-22	9,183	-	-	-	9,183	26.023%	2,390
Sep-22	(50)	-	-	-	(50)	26.023%	(13)
Oct-22	3,727	-	-	-	3,727	26.023%	970
Nov-22	(7,340)	-	-	-	(7,340)	26.023%	(1,910)
Dec-22	-	-	-	-	-	26.023%	-
Jan-23	223	-	-	-	223	26.002%	58
Feb-23	268	-	-	-	268	26.002%	70
	454,919	217,970	158,740	33,250	864,880		**225,289**

Total O&M Deferred	**2,297,213**

PacifiCorp
Oregon General Rate Case - December 2025
Wildfire Restoration Costs Deferral Amortization
Revenue Requirement Variables

Capital Cost and Structure Ordered from Oregon 2014 General Rate Case
Reference UE-263, Compliance Filing

	Capital Structure	Embedded Cost	Weighted Cost	Pre-Tax Bump-up	Pre-Tax Revenue Requirement
Debt	47.60%	5.25%	2.499%		2.499%
Preferred	0.30%	5.43%	0.016%	132.60%	0.022%
Common	52.10%	9.80%	5.106%	132.60%	6.770%
Total	100.00%		7.621%		9.291%

Merged Effective Tax Rate	24.587%
Pre-Tax Bump-up Factor	132.60%

2010 Protocol Allocation Factors

Forecast 2014 SG Factor [1]	26.0530%
Oregon GPS Factor [2]	27.3843%

Property Tax Calculation

Total Company	116,729,123
Oregon GPS Factor [2]	27.3843%
Oregon Property Taxes	31,965,402
Oregon Gross EPIS	6,675,127,527
Oregon Accum. Depr.	(2,359,864,735)
Oregon Accum. Amort.	(152,115,135)
Oregon Net EPIS	4,163,147,657
Estimated Oregon Property Tax Rate	0.768%

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 =	132.60%

2020 Protocol Allocation Factors

Approved 2021 SG Factor [3]	26.0226%
Oregon GPS Factor [3]	27.1871%

Property Tax Calculation as filed in Oregon General Rate Case Docket No. UE 374

Total Company	179,328,000
Oregon GPS Factor [3]	27.1871%
Oregon Property Taxes	48,754,134
Oregon Gross EPIS	8,094,635,058
Oregon Accum. Depr.	(3,179,075,480)
Oregon Accum. Amort.	(190,424,115)
Oregon Net EPIS	4,725,135,463
Estimated Oregon Property Tax Rate	1.032%

Capital Cost and Structure Ordered from Oregon 2023 General Rate Case
Reference UE-399, Compliance Filing

	Capital Structure	Embedded Cost	Weighted Cost	Pre-Tax Bump-up	Pre-Tax Revenue Requirement
Debt	49.99%	4.72%	2.358%		2.358%
Preferred	0.01%	6.75%	0.001%	132.60%	0.001%
Common	50.00%	9.50%	4.750%	132.60%	6.299%
Total	100.00%		7.109%		8.658%

Merged Effective Tax Rate	24.587%
Pre-Tax Bump-up Factor	132.60%

2020 Protocol Allocation Factors

Forecast 2023 SG Factor [4]	26.0018%
Oregon GPS Factor [4]	27.0866%

Property Tax Calculation

Total Company	185,977,000
Oregon GPS Factor [4]	27.0866%
Oregon Property Taxes	50,374,880
Oregon Gross EPIS	8,800,629,820
Oregon Accum. Depr.	(3,558,696,312)
Oregon Accum. Amort.	(217,647,490)
Oregon Net EPIS	5,024,286,018
Estimated Oregon Property Tax Rate	1.003%

Footnotes:
1 SG Factor from OR 2014 GRC
2 GPS Factor from OR 2014 GRC
3 Oregon General Rate Case Docket No. UE 374 Compliance Filing Jurisdictional Allocation Model (JAM)
4 Oregon General Rate Case Docket No. UE 399 Compliance Filing Jurisdictional Allocation Model (JAM)

PacifiCorp
Oregon General Rate Case - December 2025
Aeolus Substation Settlement

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Reserves:							
Aeolus Substation Settlement	108TP	1	(6,000,000)	SG	26.884%	(1,613,049)	8.19.1
Adjustment to Tax:							
ADIT Balance	282	1	1,475,196	SG	26.884%	396,594	

Description of Adjustment:

In the Settlement Stipulation from Company's most recently concluded rate case, docket UE 399, the Company affirmed that none of the plant repairs that resulted from the transformer outage at the Aeolus Substation on September 30, 2021 had been included in the docket UE 399 rate case. Stipulating Parties agreed that any funds recovered from third parties related to such repairs, not related to reimbursement of power costs, will be used to credit rate base to offset, in part, or in full, the plant repair costs in the event the Company includes such costs in any future rate filing. The referenced settlement payment was received in September 30, 2023, which is beyond the Company's base period data from 12 months ended June 2023 used as the starting point to build the current general rate case. This adjustment adds into results the settlement amount received from a contractor with regards to these repairs.

PacifiCorp
Oregon General Rate Case - December 2025
Aeolus Substation Settlement

		Amount	
Aeolus Substation Settlement	$	6,000,000	**Ref 8.19**

PacifiCorp
Oregon General Rate Case - December 2025
Klamath Regulatory Asset

	ACCOUNT	Type	TOTAL COMPANY	FACTOR	FACTOR %	OREGON ALLOCATED	REF#
Adjustment to Expense:							
Base Period O&M Expense Adjustment	535	1	(2,095,842)	SG	26.884%	(563,449)	8.20.1
Amortization Expense Adjustment	407	3	1,276,279	SG	26.884%	343,117	8.20.2
			(819,563)			(220,332)	
Adjustment to Rate Base:							
Klamath Regulatory Asset	182M	3	(5,177,820)	SG	26.884%	(1,392,013)	8.20.2
Adjustment to Tax:							
Remove base period tax:							
Schedule M Addition	SCHMDT	3	(622,467)	SG	26.884%	(167,345)	
Deferred Income Tax Expense	41010	3	(153,043)	SG	26.884%	(41,144)	
Accum Def Inc Tax Bal	283	3	1,273,050	SG	26.884%	342,249	

Description of Adjustment:

The Lower Klamath hydroelectric generation assets were transferred to KRRC for final decommissioning in December 2022. Accordingly, the remaining net plant balance was initially reclassified from Hydro Plant to Intangible Plant, and the Company continued to assume depreciation on the intangible plant assets using a 20% rate (i.e. 5 years depreciable life) consistent with the rate requested and approved in Docket UE 374 for Klamath assets. A subsequent determination from FERC denied the Company's inclusion of the balance as Intangible, and the balance was then reclassified as a regulatory asset. The Company continues to amortize this balance, now classified as a regulatory asset, assuming the 5 years' amortization life previously established for Klamath assets. In this case, the Company is proposing to continue this amortization through 2027, for the regulatory asset to be fully amortized five years after the balance was reclassified out of electric plant in-service (EPIS) balance at the end of 2022. The Company is also removing the regulatory asset balance from Test Period rate base, as these assets no longer meet the used and useful statute for Oregon customers.

PacifiCorp
Oregon General Rate Case - December 2025
Klamath Regulatory Asset
Remove Base Period O&M Expense

	FACTOR	TOTAL COMPANY
Expense Accounts		
Remove base period O&M expense[1]	SG	$ 2,095,842
Adjustment to Expense Accounts		**$ 2,095,842**

[1] The FERC Location Codes included in this line item include the following:
18000
610000
611000
612000

PacifiCorp
Oregon General Rate Case - December 2025
Klamath Regulatory Asset
Regulatory Asset Balance and Amortization

Regulatory Assets	June 2023 EOP Balance	December 2025 13 MA Balance[1]	Difference
Klamath Regulatory Asset	$ 5,177,820	$ -	$ (5,177,820)

Amortization Expense	12 ME June 2023	12 ME December 2025	Difference
Klamath Amortization Expense	$ -	$ 1,276,279	$ 1,276,279

Date	Beg Bal	Adjustment	Amortization	Interest	End Bal
Apr-23	$ 5,807,842	$ (425,795)			$ 5,382,046
May-23	$ 5,382,046	$ (107,445)			$ 5,274,601
Jun-23	$ 5,274,601	$ (96,782)			$ 5,177,820
Jul-23	$ 5,177,820	$ (96,782)			$ 5,081,038
Aug-23	$ 5,081,038	$ (104,676)			$ 4,976,362
Sep-23	$ 4,976,362	$ (96,628)			$ 4,879,734
Oct-23	$ 4,879,734	$ 49,882			$ 4,929,616
Nov-23	$ 4,929,616	$ (99,588)			$ 4,830,028
Dec-23	$ 4,830,028	$ (99,533)			$ 4,730,495
Jan-24	$ 4,730,495	$ (99,589)	$ -		$ 4,630,906
Feb-24	$ 4,630,906	$ (99,589)	$ -		$ 4,531,316
Mar-24	$ 4,531,316	$ (99,589)	$ -		$ 4,431,727
Apr-24	$ 4,431,727	$ (99,589)	$ -		$ 4,332,138
May-24	$ 4,332,138	$ (99,589)	$ -		$ 4,232,548
Jun-24	$ 4,232,548	$ (99,589)	$ -		$ 4,132,959
Jul-24	$ 4,132,959	$ (99,589)	$ -		$ 4,033,370
Aug-24	$ 4,033,370	$ (99,589)	$ -		$ 3,933,780
Sep-24	$ 3,933,780	$ (99,589)	$ -		$ 3,834,191
Oct-24	$ 3,834,191	$ (99,589)	$ -		$ 3,734,601
Nov-24	$ 3,734,601	$ (99,589)	$ -		$ 3,635,012
Dec-24	$ 3,635,012	$ (99,589)	$ -		$ 3,535,423
Annual Total			$ -		
Date	**Beg Bal**	**Adjustment**	**Amortization**	**Interest**	**End Bal**
Jan-25	$ 3,535,423		$ (106,357)	15,670	$ 3,444,736
Feb-25	$ 3,444,736		$ (106,357)	15,262	$ 3,353,642
Mar-25	$ 3,353,642		$ (106,357)	14,852	$ 3,262,137
Apr-25	$ 3,262,137		$ (106,357)	14,440	$ 3,170,221
May-25	$ 3,170,221		$ (106,357)	14,027	$ 3,077,891
Jun-25	$ 3,077,891		$ (106,357)	13,611	$ 2,985,146
Jul-25	$ 2,985,146		$ (106,357)	13,194	$ 2,891,983
Aug-25	$ 2,891,983		$ (106,357)	12,775	$ 2,798,401
Sep-25	$ 2,798,401		$ (106,357)	12,354	$ 2,704,398
Oct-25	$ 2,704,398		$ (106,357)	11,930	$ 2,609,972
Nov-25	$ 2,609,972		$ (106,357)	11,506	$ 2,515,121
Dec-25	$ 2,515,121		$ (106,357)	11,079	$ 2,419,843
Annual Total			**$ (1,276,279)**		

1. Regulatory asset balance no longer to be included in Test Period rate base in accordance with Oregon's used and useful statute.
2. Interest accrual at Modified Blended Treasury Rate as of date of the Commission's approval of the amortization (i.e. Dec 2024).

	2024	
MBTR	5.400%	Ref UM-1147

Tab 7 - Bwl_kga CAB

OREGON
ANNUAL EMBEDDED COSTS
Twelve Months Ending December 31, 2025
YEAR END BALANCE

Company Owned Hydro - West

Account	Description	Amount	Mwh	$/Mwh	Differential
535 - 545	Hydro Operation & Maintenance Expense	38,795,901			
403HP	Hydro Depreciation Expense	36,003,829			
404IP / 404HP	Hydro Relicensing Amortization	3,073,055			
	Total West Hydro Operating Expense	**77,872,785**			
330 - 336	Hydro Electric Plant in Service	962,616,236			
302 & 182M	Hydro Relicensing	103,371,094			
108HP	Hydro Accumulated Depreciation Reserve	(368,746,085)			
111IP	Hydro Relicensing Accumulated Reserve	(49,765,034)			
154	Materials and Supplies	33,938			
	West Hydro Net Rate Base	**647,510,149**			
	Pre-tax Return	9.42%			
	Rate Base Revenue Requirement	**60,991,585**			
	Annual Embedded Cost				
	West Hydro-Electric Resources	**138,864,370**	2,590,238	53.61	(59,968,100)

Mid C Contracts

Account	Description	Amount	Mwh	$/Mwh	Differential
555	Annual Mid-C Contracts Costs	124,786,376	1,017,600	122.63	46,673,151
	Grant Reasonable Portion	(15,474,138)			(15,474,138)
		109,312,238			31,199,013

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	887,904,216		
535 - 545	East Hydro Operation & Maintenance Expense	13,983,045		
546 - 554	Other Generation Operation & Maintenance Expense	62,838,482		
555	Other Purchased Power Contracts	0		
40910	Production Tax Credit	0		
4118	SO2 Emission Allowances	(91)		
456	James River / Little Mountain Offset	0		
456	REC Revenues	0		
403SP	Steam Depreciation Expense	422,670,138		
403HP	East Hydro Depreciation Expense	10,682,066		
403OP	Other Generation Depreciation Expense	13,358,583		
403MP	Mining Depreciation Expense	0		
404IP	East Hydro Relicensing Amortization	327,097		
406	Amortization of Plant Acquisition Costs	0		
	Total All Other Operating Expenses	**1,411,763,537**		
310 - 316	Steam Electric Plant in Service	7,088,173,533		
330 - 336	East Hydro Electric Plant in Service	235,767,710		
302 & 186M	East Hydro Relicensing	10,233,245		
340 - 346	Other Electric Plant in Service	275,041,077		
399	Mining	44,290,377		
108SP	Steam Accumulated Depreciation Reserve	(5,308,691,113)		
108OP	Other Generation Accumulated Depreciation Reserve	(161,117,831)		
108MP	Other Accumulated Depreciation Reserve	0		
108HP	East Hydro Accumulated Depreciation Reserve	(120,391,549)		
111IP	East Hydro Relicensing Accumulated Reserve	(7,032,879)		
114	Electric Plant Acquisition Adjustment	141,186,242		
115	Accumulated Provision Acquisition Adjustment	(141,186,242)		
151	Fuel Stock	136,992,309		
253.16 - 253.19	Joint Owner WC Deposit	(4,222,210)		
253.98	SO2 Emission Allowances	0		
154	Materials & Supplies	93,576,155		
154	East Hydro Materials & Supplies			
	Total Net Rate Base	**2,282,618,825**		
	Pre-tax Return	9.42%		
	Rate Base Revenue Requirement	**215,009,047**		
	Annual Embedded Cost			
	All Other Generation Resources	**1,626,772,584**	21,192,356	76.76
	Total Annual Embedded Costs	**1,874,949,192**	**24,800,193**	**75.60**

Tab 10 - 2020 Protocol Factors

Oregon General Rate Case
Pro Forma Factors December 2025
2020 Protocol Factors

OREGON GENERAL RATE CASE
Pro Forma Factors December 31, 2025

DESCRIPTION	2020 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
Situs	S		-	-	-	-	-	-	-	-	-	Situs
System Generation	SG		1.3769%	26.8842%	7.4882%	44.8803%	5.5943%	13.7762%	0.0000%	0.0000%	0.0000%	Pg 10.13
System Generation (Pac. Power Costs on SG)	SG-P		1.3769%	26.8842%	7.4882%	44.8803%	5.5943%	13.7762%	0.0000%	0.0000%	0.0000%	Pg 10.13
System Generation (R.M.P. Costs on SG)	SG-U		1.3769%	26.8842%	7.4882%	44.8803%	5.5943%	13.7762%	0.0000%	0.0000%	0.0000%	Pg 10.13
System Generation (Wind Plant on SG)	SG-W		1.3769%	26.8842%	7.4882%	44.8803%	5.5943%	13.7762%	0.0000%	0.0000%	0.0000%	Pg 10.13
Divisional Generation - Pac. Power	DGP		2.8793%	56.2204%	15.6595%	0.0000%	0.0000%	25.2408%	0.0000%	0.0000%	0.0000%	Pg 10.13
Divisional Generation - R.M.P.	DGU		0.0000%	0.0000%	0.0000%	86.0093%	10.7209%	3.2698%	0.0000%	0.0000%	0.0000%	Pg 10.13
System Capacity	SC		1.4122%	27.0658%	7.7109%	44.9415%	5.4541%	13.4155%	0.0000%	0.0000%	0.0000%	Pg 10.13
System Energy	SE		1.2710%	26.3391%	6.8201%	44.6968%	6.0148%	14.8582%	0.0000%	0.0000%	0.0000%	Pg 10.13
System Overhead	SO		2.6234%	27.4255%	7.3164%	44.4648%	5.4524%	12.7175%	0.0000%	0.0000%	0.0000%	Pg 10.7
Gross Plant-System	GPS		2.6234%	27.4255%	7.3164%	44.4648%	5.4524%	12.7175%	0.0000%	0.0000%	0.0000%	Pg 10.6
System Net Plant	SNP		2.8403%	26.1357%	7.0293%	45.9446%	5.5041%	12.5460%	0.0000%	0.0000%	0.0000%	Pg 10.7
Division Net Plant Distribution	SNPD		6.7499%	24.9984%	5.7929%	48.8998%	4.9603%	8.5987%	0.0000%	0.0000%	0.0000%	Pg 10.5
Customer - System	CN		2.2647%	30.7055%	6.6914%	48.9947%	4.2449%	7.0987%	0.0000%	0.0000%	0.0000%	Pg 10.8
CIAC	CIAC		6.7499%	24.9984%	5.7929%	48.8998%	4.9603%	8.5987%	0.0000%	0.0000%	0.0000%	Pg 10.8
Bad Debt Expense	BADDEBT		2.9719%	38.9386%	27.0279%	24.1353%	1.8332%	5.0931%	0.0000%	0.0000%	0.0000%	Pg 10.7
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		1.4385%	28.0873%	7.2168%	43.9912%	5.6441%	13.6221%	0.0000%	0.0000%	0.0000%	Pg 10.3
System Net Transmission Plant	SNPT		1.3769%	26.8842%	7.4882%	44.8803%	5.5943%	13.7762%	0.0000%	0.0000%	0.0000%	Pg 10.4
System Net Production Plant	SNPP		1.4228%	25.3626%	7.6129%	45.7852%	5.7396%	14.0768%	0.0000%	0.0000%	0.0000%	Pg 10.4
System Net Hydro Plant	SNPPH		1.3769%	26.8842%	7.4882%	44.8803%	5.5943%	13.7762%	0.0000%	0.0000%	0.0000%	Pg 10.3
System Net Other Production Plant	SNPPO		1.4247%	24.3384%	7.7481%	46.4460%	5.7884%	14.2544%	0.0000%	0.0000%	0.0000%	Pg 10.4
System Net General Plant	SNPG		2.5725%	31.4166%	6.1391%	39.5253%	6.1111%	14.2354%	0.0000%	0.0000%	0.0000%	Pg 10.5
System Net Intangible Plant	SNPI		2.1826%	27.0492%	7.4224%	44.2227%	5.8924%	13.2307%	0.0000%	0.0000%	0.0000%	Pg 10.6
Trojan Plant Allocator	TROJP		1.3608%	26.8014%	7.3867%	44.8524%	5.6581%	13.9405%	0.0000%	0.0000%	0.0000%	Pg 10.9
Trojan Decommissioning Allocator	TROJD		1.3579%	26.7867%	7.3688%	44.8475%	5.6694%	13.9696%	0.0000%	0.0000%	0.0000%	Pg 10.9
DIT Balance	DITBAL		1.9553%	24.9505%	7.0484%	46.9306%	5.6230%	13.5168%	0.0000%	-0.0247%	0.0000%	Pg 10.7
Tax Depreciation	TAXDEPR		2.7478%	26.2950%	7.2629%	45.5499%	5.6590%	12.4771%	0.0000%	0.0083%	0.0000%	Pg 10.10
SCHMAT Depreciation Expense	SCHMDEXP		2.4705%	26.8124%	7.4062%	44.7448%	5.4869%	13.0792%	0.0000%	0.0000%	0.0000%	Pg 10.10
System Generation Cholla Transaction	SGCT		1.3769%	26.8842%	7.4882%	44.8803%	5.5943%	13.7762%	0.0000%	0.0000%	0.0000%	Pg 10.2

OREGON GENERAL RATE CASE
Pro Forma Factors December 31, 2025

DESCRIPTION	2020 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
CALCULATION OF INTERNAL FACTORS												
Pro Forma Factors December 31, 2025												
DESCRIPTION OF FACTOR		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**OTHER**	**NUTIL**	
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	7,128,586,264	98,151,167	1,916,460,328	533,804,773	3,199,331,834	398,791,018	982,047,142	1	0	0	
	SSGCH	0	0	0	0	0	0	0	0	0	0	
		7,128,586,264	98,151,167	1,916,460,328	533,804,773	3,199,331,834	398,791,018	982,047,142	1	0	0	
LESS ACCUMULATED DEPRECIATION												
	S	(65,845,207)	0	0	(8,924,040)	(42,634,073)	(2,949,415)	(11,337,680)	0	0	0	
	DGP	(824,873,009)	(11,357,406)	(221,760,155)	(61,768,369)	(370,205,589)	(46,145,468)	(113,636,021)	(0)	0	0	
	DGU	(769,219,505)	(10,591,131)	(206,798,180)	(57,600,908)	(345,228,122)	(43,032,071)	(105,969,092)	(0)	0	0	
	SG	(3,997,300,692)	(55,037,523)	(1,074,640,597)	(299,326,979)	(1,794,001,066)	(223,619,039)	(550,675,488)	(1)	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	
		(5,657,238,413)	(76,986,060)	(1,503,198,932)	(427,620,296)	(2,552,068,850)	(315,745,993)	(781,618,282)	(1)	0	0	
TOTAL NET STEAM PLANT		1,471,347,851	21,165,107	413,261,396	106,184,477	647,262,985	83,045,025	200,428,860	0	0	0	
SNPPS												
SYSTEM NET PLANT PRODUCTION STEAM		100.0000%	1.4385%	28.0873%	7.2168%	43.9912%	5.6441%	13.6221%	0.0000%	0.0000%	0.0000%	
HYDRO:		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**OTHER**	**NUTIL**	
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	1,197,062,350	16,481,959	321,820,122	89,638,755	537,245,331	66,966,674	164,909,509	0	0	0	
		1,197,062,350	16,481,959	321,820,122	89,638,755	537,245,331	66,966,674	164,909,509	0	0	0	
LESS ACCUMULATED DEPRECIATION (incl hydro amortization)												
	S	-	-	-	-	-	-	0	0	0	0	
	DGP	(145,923,755)	(2,009,176)	(39,230,371)	(10,927,103)	(65,491,038)	(8,163,341)	(20,102,725)	0	0	0	
	DGU	(32,553,755)	(448,222)	(8,751,803)	(2,437,699)	(14,610,227)	(1,821,139)	(4,484,665)	(0)	0	0	
	SG	(314,895,690)	(4,335,696)	(84,657,052)	(23,580,106)	(141,326,171)	(17,616,056)	(43,380,609)	(0)	0	0	
		(493,373,199)	(6,793,094)	(132,639,226)	(36,944,909)	(221,427,436)	(27,600,536)	(67,967,998)	(0)	0	0	
TOTAL NET HYDRO PRODUCTION PLANT		703,689,151	9,688,865	189,180,897	52,693,846	315,817,894	39,366,138	96,941,510	(0)	0	0	
SNPPH												
SYSTEM NET PLANT PRODUCTION HYDRO		100.0000%	1.3769%	26.8842%	7.4882%	44.8803%	5.5943%	13.7762%	0.0000%	0.0000%	0.0000%	

OREGON GENERAL RATE CASE
Pro Forma Factors December 31, 2025

DESCRIPTION	2020 PROTOCOL FACTOR	TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL FERC	OTHER	NON-UTILITY NUTIL	Page Ref.
OTHER:												
OTHER PRODUCTION PLANT (EXCLUDES EXPERIMENTAL)												
	S	1,400,215	0	965,360	0	434,855	0	0	0	0	0	
	DGU	0	0	0	0	0	0	0	0	0	0	
	SG	5,904,487,236	81,296,949	1,587,371,623	442,141,450	2,649,952,358	330,311,844	813,413,011	1	0	0	
	SSGCT	0	0	0	0	0	0	0	0	0	0	
		5,905,887,451	81,296,949	1,588,336,982	442,141,450	2,650,387,213	330,311,844	813,413,011	1	0	0	
LESS ACCUMULATED DEPRECIATION												
	S	(173,198,503)	-	(173,154,068)	-	(44,436)	-	0	0	0	0	
	DGP	(91,457,351)	(1,259,246)	(24,587,538)	(6,848,535)	(41,046,345)	(5,116,354)	(12,599,333)	0	0	0	
	DGU	-	-	-	-	-	-	0	(0)	0	0	
	SG	(641,654,082)	(8,834,725)	(172,503,291)	(48,048,519)	(287,976,361)	(35,895,741)	(88,395,445)	0	0	0	
	SSGCT	(50,136,554)	(690,314)	(13,478,790)	(3,754,339)	(22,501,443)	(2,804,765)	(6,906,904)	(0)	0	0	
		(956,446,490)	(10,784,285)	(383,723,687)	(58,651,393)	(351,568,585)	(43,816,859)	(107,901,682)	(0)	0	0	
TOTAL NET OTHER PRODUCTION PLANT		4,949,440,960	70,512,664	1,204,613,295	383,490,057	2,298,818,629	286,494,985	705,511,329	1	0	0	
SNPPO												
SYSTEM NET PLANT PRODUCTION OTHER		100.0000%	1.4247%	24.3384%	7.7481%	46.4460%	5.7884%	14.2544%	0.0000%	0.0000%	0.0000%	
PRODUCTION:		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**OTHER**	**NUTIL**	
TOTAL PRODUCTION PLANT												
	S	1,400,215	0	965,360	0	434,855	0	0	0	0	0	
	DGP & DGU	0	0	0	0	0	0	0	0	0	0	
	SG	14,230,135,850	195,930,076	3,825,652,073	1,065,584,978	6,386,529,523	796,069,536	1,960,369,662	2	0	0	
	SSGCH	0	0	0	0	0	0	0	0	0	0	
	SSGCT	0	0	0	0	0	0	0	0	0	0	
		14,231,536,065	195,930,076	3,826,617,433	1,065,584,978	6,386,964,379	796,069,536	1,960,369,662	2	0	0	
LESS ACCUMULATED DEPRECIATION												
	S	(239,043,711)	-	(173,154,068)	(8,924,040)	(42,678,508)	(2,949,415)	(11,337,680)	0	0	0	
	DGP	-	-	-	-	-	-	0	0	0	0	
	DGU	-	-	-	-	-	-	0	0	0	0	
	SG-P	(6,874,634,008)	(94,654,582)	(1,848,187,404)	(514,788,250)	(3,085,357,267)	(384,584,291)	(947,062,213)	(1)	0	0	
	SSGCH	-	-	-	-	-	-	0	0	0	0	
	SSGCT	-	-	-	-	-	-	0	0	0	0	
		(7,113,677,718)	(94,654,582)	(2,021,341,472)	(523,712,289)	(3,128,035,775)	(387,533,706)	(958,399,893)	(1)	0	0	
TOTAL NET PRODUCTION PLANT		7,117,858,347	101,275,494	1,805,275,960	541,872,688	3,258,928,604	408,535,830	1,001,969,769	1	0	0	
SNPP												
SYSTEM NET PRODUCTION PLANT		100.0000%	1.4228%	25.3626%	7.6129%	45.7852%	5.7396%	14.0768%	0.0000%	0.0000%	0.0000%	
TRANSMISSION:		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**			
TRANSMISSION PLANT												
	DGP	0	0	0	0	0	0	0	0			
	DGU	0	0	0	0	0	0	0	0			
	SG	11,258,437,370	155,013,733	3,026,735,986	843,057,428	5,052,821,941	629,825,260	1,550,983,019	2			
		11,258,437,370	155,013,733	3,026,735,986	843,057,428	5,052,821,941	629,825,260	1,550,983,019	2			
LESS ACCUMULATED DEPRECIATION												
	DGP	(349,536,968)	(4,812,660)	(93,970,067)	(26,174,124)	(156,873,285)	(19,553,976)	(48,152,855)	0			
	DGU	(420,976,303)	(5,796,285)	(113,175,930)	(31,523,664)	(188,935,483)	(23,550,472)	(57,994,469)	(0)			
	SG	(1,654,652,610)	(22,782,369)	(444,839,407)	(123,904,155)	(742,613,272)	(92,565,422)	(227,947,984)	(0)			
		(2,425,165,880)	(33,391,314)	(651,985,404)	(181,601,944)	(1,088,422,040)	(135,669,870)	(334,095,308)	(0)			
TOTAL NET TRANSMISSION PLANT		8,833,271,490	121,622,419	2,374,750,582	661,455,484	3,964,399,901	494,155,391	1,216,887,711	2			
SNPT												
SYSTEM NET PLANT TRANSMISSION		100.0000%	1.3769%	26.8842%	7.4882%	44.8803%	5.5943%	13.7762%	0.0000%			

OREGON GENERAL RATE CASE
Pro Forma Factors December 31, 2025

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	4,719,133,289	576,351,800	2,705,369,051	662,561,779	0	0	774,850,658	0			
LESS ACCUMULATED DEPRECIATION	S	(2,011,645,188)	(167,750,424)	(1,192,111,426)	(311,895,255)	0	0	(339,888,083)	0			
		2,707,488,100	408,601,375	1,513,257,625	350,666,525	0	0	434,962,575	0			
DNPDP **DIVISION NET PLANT DISTRIBUTION PACIFIC POWER**		100.0000%	15.0915%	55.8916%	12.9517%	0.0000%	0.0000%	16.0652%	0.0000%			
DISTRIBUTION PLANT - ROCKY MOUNTAIN POWER	S	4,828,485,852	0	0	0	4,206,065,758	469,339,885	153,080,209	0			
LESS ACCUMULATED DEPRECIATION	S	(1,482,557,665)	0	0	0	(1,245,956,733)	(169,071,974)	(67,528,959)	0			
		3,345,928,187	0	0	0	2,960,109,025	300,267,912	85,551,250	0			
DNPDU **DIVISION NET PLANT DISTRIBUTION R.M.P.**		100.0000%	0.0000%	0.0000%	0.0000%	88.4690%	8.9741%	2.5569%	0.0000%			
TOTAL NET DISTRIBUTION PLANT		6,053,416,287	408,601,375	1,513,257,625	350,666,525	2,960,109,025	300,267,912	520,513,825	0			
DNPD & SNPD **SYSTEM NET PLANT DISTRIBUTION**		100.0000%	6.7499%	24.9984%	5.7929%	48.8998%	4.9603%	8.5987%	0.0000%			
GENERAL:		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**			
GENERAL PLANT	S	866,636,774	24,401,398	286,795,556	56,023,197	308,036,456	61,088,897	130,291,269	0			
	DGP	0	0	0	0	0	0	0	0			
	DGU	0	0	0	0	0	0	0	0			
	SE	3,149,128	40,024	829,453	214,774	1,407,560	189,414	467,902	0			
	SG	334,957,591	4,611,921	90,050,525	25,082,387	150,330,016	18,738,369	46,144,373	0			
	SO	447,971,449	11,752,119	122,858,256	32,775,260	199,189,790	24,425,252	56,970,772	0			
	CN	13,821,444	313,020	4,243,948	924,845	6,771,776	586,712	981,143	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	(8,749,266)	(110,950)	(2,857,500)	(603,411)	(3,616,511)	(450,792)	(1,110,102)	0			
		1,657,787,121	41,007,533	501,920,238	114,417,053	662,119,087	104,577,852	233,745,357	0			
LESS ACCUMULATED DEPRECIATION	S	(344,108,168)	(9,081,357)	(102,015,010)	(29,968,490)	(126,986,492)	(26,126,611)	(49,930,208)	0			
	DGP	(473,066)	(6,513)	(127,180)	(35,424)	(212,313)	(26,464)	(65,170)	0			
	DGU	(2,092,186)	(28,807)	(562,467)	(156,668)	(938,980)	(117,042)	(288,223)	(0)			
	SE	(1,912,546)	(24,308)	(503,748)	(130,438)	(854,847)	(115,036)	(284,169)	(0)			
	SG	(155,924,142)	(2,146,868)	(41,918,891)	(11,675,955)	(69,979,243)	(8,722,788)	(21,480,396)	(0)			
	SO	(137,334,690)	(3,602,849)	(37,664,678)	(10,047,917)	(61,065,651)	(7,488,054)	(17,465,540)	(0)			
	CN	(5,485,751)	(124,238)	(1,684,429)	(367,072)	(2,687,728)	(232,867)	(389,417)	(0)			
	SSGCT	(149,363)	(2,057)	(40,155)	(11,185)	(67,034)	(8,356)	(20,576)	0			
	SSGCH	0	0	0	0	0	0	0	(0)			
		(647,479,912)	(15,016,997)	(184,516,558)	(52,393,149)	(262,792,288)	(42,837,219)	(89,923,701)	(0)			
TOTAL NET GENERAL PLANT		1,010,307,208	25,990,535	317,403,680	62,023,904	399,326,799	61,740,634	143,821,656	0			
SNPG **SYSTEM NET GENERAL PLANT**		100.0000%	2.5725%	31.4166%	6.1391%	39.5253%	6.1111%	14.2354%	0.0000%			

OREGON GENERAL RATE CASE
Pro Forma Factors December 31, 2025

DESCRIPTION	2020 PROTOCOL FACTOR	TOTAL	California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL FERC	OTHER	NON-UTILITY	Page Ref.
MINING:												
GENERAL MINING PLANT												
	SE	44,290,377	562,913	11,665,695	3,020,658	19,796,393	2,663,985	6,580,733	0			
LESS ACCUMULATED DEPRECIATION												
	SE	0	0	0	0	0	0	0	0			
		44,290,377	562,913	11,665,695	3,020,658	19,796,393	2,663,985	6,580,733	0			
SNPM												
SYSTEM NET PLANT MINING		100.0000%	1.2710%	26.3391%	6.8201%	44.6968%	6.0148%	14.8582%	0.0000%			
INTANGIBLE:		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**			
INTANGIBLE PLANT												
	S	24,279,307	472,167	4,606,407	2,021,868	7,520,237	4,356,073	5,302,554	0			
	DGP	0	0	0	0	0	0	0	0			
	DGU	0	0	0	0	0	0	0	0			
	SE	4,710	60	1,241	321	2,105	283	700	0			
	CN	229,473,811	5,196,989	70,461,152	15,354,965	112,430,024	9,741,028	16,289,653	0			
	SG	324,637,101	4,469,822	87,275,948	24,309,565	145,698,147	18,161,015	44,722,604	0			
	SO	696,998,520	18,285,115	191,155,091	50,995,007	309,919,280	38,003,236	88,640,791	0			
	SSGCT	0	0	0	0	0	0	0	0			
	SSGCH	0	0	0	0	0	0	0	0			
		1,275,393,448	28,424,152	353,499,838	92,681,728	575,569,793	70,261,635	154,956,302	0			
LESS ACCUMULATED AMORTIZATION												
	S	(1,871,328)	174	(159,409)	(545)	(350,268)	(999,482)	(361,798)	0			
	DGP	0	0	0	0	0	0	0	0			
	DGU	(421,999)	(5,810)	(113,451)	(31,600)	(189,395)	(23,608)	(58,135)	0			
	SE	(2,923)	(37)	(770)	(199)	(1,307)	(176)	(434)	(0)			
	CN	(206,894,836)	(4,685,633)	(63,528,158)	(13,844,120)	(101,367,521)	(8,782,564)	(14,686,840)	(0)			
	SG	(173,094,907)	(2,383,287)	(46,535,107)	(12,961,741)	(77,685,536)	(9,683,364)	(23,845,872)	0			
	SO	(421,136,121)	(11,048,119)	(115,498,543)	(30,811,887)	(187,257,505)	(22,962,079)	(53,557,989)	(0)			
	SSGCT	0	0	0	0	0	0	0	(0)			
	SSGCH	0	0	0	0	0	0	0	0			
		(803,422,114)	(18,122,713)	(225,835,437)	(57,650,093)	(366,851,530)	(42,451,273)	(92,511,068)	(0)			
TOTAL NET INTANGIBLE PLANT		471,971,334	10,301,440	127,664,401	35,031,635	208,718,263	27,810,362	62,445,233	0			
SNPI												
SYSTEM NET INTANGIBLE PLANT		100.0000%	2.1826%	27.0492%	7.4224%	44.2227%	5.8924%	13.2307%	0.0000%			
GROSS PLANT:		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**OTHER**	**NUTIL**	
PRODUCTION PLANT		14,231,536,065	195,930,076	3,826,617,433	1,065,584,978	6,386,964,379	796,069,536	2	2	0	0	
TRANSMISSION PLANT		11,258,437,370	155,013,733	3,026,735,986	843,057,428	5,052,821,941	629,825,260	1,550,983,019	2	0	0	
DISTRIBUTION PLANT		9,547,619,141	576,351,800	2,705,369,051	662,561,779	4,206,065,758	469,339,885	927,930,867	0	0	0	
GENERAL PLANT		1,702,077,498	41,570,446	513,585,933	117,437,711	681,915,481	107,241,838	240,326,089	0	0	0	
INTANGIBLE PLANT		1,275,393,448	28,424,152	353,499,838	92,681,728	575,569,793	70,261,635	154,956,302	0	0	0	
TOTAL GROSS PLANT		38,015,063,522	997,290,207	10,425,808,241	2,781,323,624	16,903,337,351	2,072,738,155	2,874,196,280	4	0	0	
GPS												
GROSS PLANT-SYSTEM FACTOR		100.0000%	2.6234%	27.4255%	7.3164%	44.4648%	5.4524%	12.7175%	0.0000%	0.0000%	0.0000%	
ACCUMULATED DEPRECIATION AND AMORTIZATION												
PRODUCTION PLANT		(7,113,677,718)	(94,654,582)	(2,021,341,472)	(523,712,289)	(3,128,035,775)	(387,533,706)	(958,399,893)	(1)	0	0	
TRANSMISSION PLANT		(2,425,165,880)	(33,391,314)	(651,985,404)	(181,601,944)	(1,088,422,040)	(135,669,870)	(334,095,308)	(0)	0	0	
DISTRIBUTION PLANT		(3,494,202,854)	(167,750,424)	(1,192,111,426)	(311,895,255)	(1,245,956,733)	(169,071,974)	(407,417,042)	0	0	0	
GENERAL PLANT		(647,479,912)	(15,016,997)	(184,516,558)	(52,393,149)	(262,792,288)	(42,837,219)	(89,923,701)	(0)	0	0	
INTANGIBLE PLANT		(803,422,114)	(18,122,713)	(225,835,437)	(57,650,093)	(366,851,530)	(42,451,273)	(92,511,068)	(0)	0	0	
		(14,483,948,479)	(328,936,030)	(4,275,790,298)	(1,127,252,730)	(6,092,058,366)	(777,564,041)	(1,882,347,011)	(2)	0	0	
NET PLANT		23,531,115,043	668,354,177	6,150,017,943	1,654,070,894	10,811,278,985	1,295,174,114	991,849,268	3	0	0	

OREGON GENERAL RATE CASE
Pro Forma Factors December 31, 2025

DESCRIPTION	2020 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
SNP												
SYSTEM NET PLANT FACTOR (SNP)		100.0000%	2.8403%	26.1357%	7.0293%	45.9446%	5.5041%	12.5460%	0.0000%	0.0000%	0.0000%	
NON-UTILITY RELATED INTEREST PERCENTAGE		0.0000%										
INT												
INTEREST FACTOR SNP - NON-UTILITY		100.0000%	2.8403%	26.1357%	7.0293%	45.9446%	5.5041%	12.5460%	0.0000%	0.0000%	0.0000%	
TOTAL GROSS PLANT (LESS SO FACTOR)		36,870,093,553	967,252,973	10,111,794,894	2,697,553,357	16,394,228,281	2,010,309,667	4,688,954,376	4	0	0	
SO												
SYSTEM OVERHEAD FACTOR (SO)		100.0000%	2.6234%	27.4255%	7.3164%	44.4648%	5.4524%	12.7175%	0.0000%	0.0000%	0.0000%	
IBT												
INCOME BEFORE TAXES		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**OTHER**	**NON-UTILITY**	
INCOME BEFORE STATE TAXES		628,110,617	(12,472,523)	112,071,272	7,008,121	(146,529,528)	2,778,823	(114,568,089)	14,356,746	765,465,795	0	
Interest Synchronization		(20,588,110)	-	-	-	-	-	-	0	(20,588,110)	0	
		607,522,507	(12,472,523)	112,071,272	7,008,121	(146,529,528)	2,778,823	(114,568,089)	14,356,746	744,877,685	0	
INCOME BEFORE TAXES (FACTOR)		100.0000%	-2.0530%	18.4473%	1.1536%	-24.1192%	0.4574%	-18.8582%	2.3632%	122.6091%	0.0000%	
See Calculation of EXCTAX												
DITBAL:		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**OTHER**	**NON-UTILITY**	
Case #1004, Report #120 (2024 OR GRC)		0	0	0	0	0	0	0	0	0	0	
Jurisdictional ADIT - 12/31/2025 - CA	S	24,390,028	24,390,028	0	0	0	0					
Jurisdictional ADIT - 12/31/2025 - ID	S	32,165,404	0	0	0	0	32,165,404	0	0	0	0	
Jurisdictional ADIT - 12/31/2025 - OTHER	S	(806,517)	0	0	0	0	0	0	0	(806,517)	0	
Jurisdictional ADIT - 12/31/2025 - OR	S	84,780,815	0	84,780,815	0	0	0	0	0	0	0	
Jurisdictional ADIT - 12/31/2025 - SG	SG	1,831,299,704	25,214,565	492,329,489	137,131,892	821,893,041	102,447,504	252,283,212	0	0	0	
Jurisdictional ADIT - 12/31/2025 - SG-CAGE	SG	540,262,976	7,438,704	145,245,147	40,456,122	242,471,715	30,223,668	74,427,620	0	0	0	
Jurisdictional ADIT - 12/31/2025 - SG-CAGW	SG	170,852,537	2,352,413	45,932,265	12,793,827	76,679,154	9,557,920	23,536,959	0	0	0	
Jurisdictional ADIT - 12/31/2025 - SO	SO	171,405,033	4,496,653	47,008,629	12,540,631	76,214,974	9,345,710	21,798,436	0	0	0	
Jurisdictional ADIT - 12/31/2025 - UT	UT	316,270,519	0	0	0	316,270,519	0	0	0	0	0	
Jurisdictional ADIT - 12/31/2025 - WA	WA	27,393,616	0	0	27,393,616	0	0	0	0	0	0	
Jurisdictional ADIT - 12/31/2025 - WY	WY	69,636,180	0	0	0	0	0	69,636,180	0	0	0	
Jurisdictional ADIT - 12/31/2025 - TOTAL		3,267,650,296	63,892,363	815,296,345	230,316,088	1,533,529,403	183,740,206	441,682,408	0	(806,517)	0	
Total PacifiCorp		3,267,650,296	63,892,363	815,296,345	230,316,088	1,533,529,403	183,740,206	441,682,408	0	(806,517)	0	
Percentage of Total (DITBAL)		100.0000%	1.9553%	24.9505%	7.0484%	46.9306%	5.6230%	13.5168%	0.0000%	-0.0247%	0.0000%	
BADDEBT												
		TOTAL	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**OTHER**	**NUTIL**	
Account 904 Balance		26,272,252	780,784	10,230,048	7,100,840	6,340,882	481,634	1,338,064	0	0	0	
Bad Debts Expense Allocation Factor - BADDEBT		100.0000%	2.9719%	38.9386%	27.0279%	24.1353%	1.8332%	5.0931%	0.0000%	0.0000%	0.0000%	

OREGON GENERAL RATE CASE
Pro Forma Factors December 31, 2025

DESCRIPTION	2020 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
Customer Factors		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**OTHER**	**NON-UTILITY**	
Total Electric Customers		2,111,374	47,817	648,309	141,280	1,034,462	89,627	149,880	0	0	0	
CN												
Customer System factor - CN		100.0000%	2.2647%	30.7055%	6.6914%	48.9947%	4.2449%	7.0987%	0.0000%	0.0000%	0.0000%	
Pacific Power Customers		970,339	47,817	648,309	141,280	0	0	132,934	0	0	0	
CNP												
Customer Service Pacific Power factor - CNP		100.0000%	4.9279%	66.8126%	14.5599%	0.0000%	0.0000%	13.6997%	0.0000%	0.0000%	0.0000%	
Rocky Mountain Power Customers		1,141,035	0	0	0	1,034,462	89,627	16,947	0	0	0	
CNU												
Customer Service R.M.P. factor - CNU		100.0000%	0.0000%	0.0000%	0.0000%	90.6600%	7.8549%	1.4852%	0.0000%	0.0000%	0.0000%	
CIAC		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**OTHER**	**NON-UTILITY**	
TOTAL NET DISTRIBUTION PLANT		6,053,416,287	408,601,375	1,513,257,625	350,666,525	2,960,109,025	300,267,912	520,513,825	0	0	0	
CIAC FACTOR: Same as (SNPD Factor)		100.0000%	6.7499%	24.9984%	5.7929%	48.8998%	4.9603%	8.5987%	0.0000%	0.0000%	0.0000%	
EXCTAX												
Excise Tax (Superfund)		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**OTHER**	**NON-UTILITY**	
Total Taxable Income		592,766,195	(11,906,271)	106,764,142	6,689,952	(139,877,087)	2,652,664	(109,366,698)	13,704,950	724,104,542	0	
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		592,766,195	(11,906,271)	106,764,142	6,689,952	(139,877,087)	2,652,664	(109,366,698)	13,704,950	724,104,542	0	
Excise Tax (Superfund) Factor - EXCTAX		100.0000%	-2.0086%	18.0112%	1.1286%	-23.5973%	0.4475%	-18.4502%	2.3120%	122.1569%	0.0000%	
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	234,158	4,572,078	1,273,492	7,632,610	951,391	2,342,859	0	0	0	
Dec 1991 Reserve		(7,851,432)										
Dec 1992 Reserve		(8,434,030)										
Average	SG	(8,142,731)	(112,115)	(2,189,105)	(609,746)	(3,654,483)	(455,525)	(1,121,758)	(0)	0	0	
Postmerger												
Dec 1991 Plant		4,284,960										
Dec 1992 Plant		3,485,613										
Average	SG	3,885,287	53,495	1,044,527	290,939	1,743,729	217,353	535,244	0	0	0	
Dec 1991 Reserve		(129,394)										
Dec 1992 Reserve		(240,609)										
Average	SG	(185,002)	(2,547)	(49,736)	(13,853)	(83,029)	(10,349)	(25,486)	0	0	0	
Net Plant		12,564,143	172,992	3,377,764	940,832	5,638,827	702,870	1,730,859	0	0	0	

OREGON GENERAL RATE CASE
Pro Forma Factors December 31, 2025

DESCRIPTION		2020 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
Division Net Plant Nuclear Pacific Power		**DNPPNP**	100.0000%	1.3769%	26.8842%	7.4882%	44.8803%	5.5943%	13.7762%	0.0000%	0.0000%	0.0000%	
Division Net Plant Nuclear Rocky Mountain Power		**DNPPNP**	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.00%	0.00%	0.00%	0.00%	
System Net Nuclear Plant		**SNNP**	100.0000%	1.3769%	26.8842%	7.4882%	44.8803%	5.5943%	13.7762%	0.0000%	0.0000%	0.0000%	

Account 182.22			**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**OTHER**	**NON-UTILITY**
Pre-merger	(101)	SG	17,094,202	235,364	4,595,632	1,280,053	7,671,931	956,293	2,354,929	0	0	0
		(108) SG	(8,434,030)	(116,125)	(2,267,418)	(631,559)	(3,785,219)	(471,821)	(1,161,887)	(0)	0	0
Post-merger	(101)	SG	3,485,613	47,992	937,078	261,011	1,564,354	194,994	480,184	0	0	0
		(108) SG	(240,609)	(3,313)	(64,686)	(18,017)	(107,986)	(13,460)	(33,147)	(0)	0	0
		(107) SG	1,778,549	24,488	478,148	133,182	798,218	99,496	245,016	0	0	0
		(120) SE	1,975,759	25,111	520,398	134,749	883,102	118,838	293,561	0	0	0
		(228) SG	7,220,849	99,422	1,941,264	540,714	3,240,740	403,952	994,757	0	0	0
		(228) SG	1,472,376	20,273	395,836	110,255	660,807	82,368	202,837	0	0	0
		(228) SNNP	3,531,000	48,617	949,280	264,409	1,584,724	197,533	486,437	0	0	0
		(228) SE	1,743,025	22,153	459,097	118,876	779,077	104,840	258,981	0	0	0
Total Acct 182.22			29,626,734	403,982	7,944,629	2,193,672	13,289,748	1,673,034	4,121,669	0	0	0
Revised Study	(228)	SNNP	112,680	1,551	30,293	8,438	50,571	6,304	15,523	0	0	0
		(228) SE	941,950	11,972	248,101	64,242	421,022	56,657	139,956	0	0	0
December 1993 Adj.			1,054,630	13,523	278,394	72,680	471,593	62,960	155,479	0	0	0
Adjusted Acct 182.22			30,681,364	417,506	8,223,023	2,266,352	13,761,340	1,735,994	4,277,149	0	0	0
TROJP Trojan Plant Allocator			100.0000%	1.3608%	26.8014%	7.3867%	44.8524%	5.6581%	13.9405%	0	0	0

Account 228.42		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**OTHER**	**NON-UTILITY**
Plant - Premerger	SG	7,220,849	99,422	1,941,264	540,714	3,240,740	403,952	994,757	0	0	0
- Postmerger	SG	1,472,376	20,273	395,836	110,255	660,807	82,368	202,837	0	0	0
Storage Facility	SE	1,743,025	22,153	459,097	118,876	779,077	104,840	258,981	0	0	0
Transition Costs	SNNP	3,531,000	48,617	949,280	264,409	1,584,724	197,533	486,437	0	0	0
Total Acct 228.42		13,967,250	190,465	3,745,477	1,034,254	6,265,347	788,694	1,943,013	0	0	0
Transition Costs	SNNP	112,680	1,551	30,293	8,438	50,571	6,304	15,523	0	0	0
Storage Facility	SE	941,950	11,972	248,101	64,242	421,022	56,657	139,956	0	0	0
December 1993 Adj.		1,054,630	13,523	278,394	72,680	471,593	62,960	155,479	0	0	0
Adjusted Acct 228.42		15,021,880	203,988	4,023,872	1,106,934	6,736,940	851,654	2,098,492	0	0	0
TROJD Trojan Decommissioning Allocator		100.0000%	1.3579%	26.7867%	7.3688%	44.8475%	5.6694%	13.9696%	0.0000%	0.0000%	0.0000%

SCHMA		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**OTHER**	**NON-UTILITY**
Amortization Expense :											
Amortization of Limited Term Plant	Acct 404	76,605,976	1,821,672	21,509,117	5,582,308	34,607,559	3,965,329	9,119,991	0	0	0
Amortization of Other Electric Plant	Acct 405	0	0	0	0	0	0	0	0	0	0
Amortization of Plant Acquisitions	Acct 406	376,987	1,037	20,258	5,642	335,453	4,215	10,381	0	0	0
Amort of Prop. Losses, Unrecovered Plant, etc.	Acct 407	23,508,908	26,619	9,375,468	144,772	3,625,422	173,934	5,013,541	0	5,149,152	0
Total Amortization Expense :		100,491,871	1,849,329	30,904,843	5,732,723	38,568,435	4,143,478	14,143,912	0	5,149,152	0
Schedule M Amortization Factor		100.0000%	1.8403%	30.7536%	5.7047%	38.3797%	4.1232%	14.0747%	0.0000%	5.1239%	0.0000%

OREGON GENERAL RATE CASE
Pro Forma Factors December 31, 2025

DESCRIPTION	2020 PROTOCOL FACTOR		California	Oregon	Washington	Utah	Idaho	Wyoming	FERC-UPL	OTHER	NON-UTILITY	Page Ref.
SCHMD		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**OTHER**	**NON-UTILITY**	
Depreciation Expense :												
Steam	Acct 403.1	421,349,103	5,801,418	113,276,155	31,551,580	189,102,797	23,571,327	58,045,827	0	0	0	
Nuclear	Acct 403.2	0	0	0	0	0	0	0	0	0	0	
Hydro	Acct 403.3	35,307,079	486,132	9,492,011	2,643,875	15,845,928	1,975,167	4,863,968	0	0	0	
Other	Acct 403.4	235,301,861	3,238,949	63,303,795	17,615,343	105,576,667	13,159,944	32,407,162	0	0	0	
Transmission	Acct 403.5	193,750,789	2,667,691	52,088,266	14,508,500	86,955,961	10,838,906	26,691,465	0	0	0	
Distribution	Acct 403.6	238,034,265	15,618,897	61,570,633	17,099,473	107,174,945	11,921,466	24,648,850	0	0	0	
General	Acct 403.7&8	58,834,749	1,402,359	17,346,823	4,164,929	24,485,803	3,419,812	8,015,023	0	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	
Postmerger Hydro Step I Adjustment		0	0	0	0	0	0	0	0	0	0	
Total Depreciation Expense :		1,182,577,845	29,215,445	317,077,683	87,583,701	529,142,101	64,886,621	154,672,295	0	0	0	
Schedule M Depreciation Factor		100.0000%	2.4705%	26.8124%	7.4062%	44.7448%	5.4869%	13.0792%	0.0000%	0.0000%	0.0000%	
TAXDEPR		**TOTAL**	**California**	**Oregon**	**Washington**	**Utah**	**Idaho**	**Wyoming**	**FERC**	**OTHER**	**NON-UTILITY**	
Jurisdictional Tax Depreciation - 12/31/2024		0	0	0	0	0	0	0	0	0	0	
									0	0	0	
Jurisdictional Tax Depreciation - 12/31/2025 - CA	S	20,925,289	20,925,289	0	0	0	0	0	0	0	0	
Jurisdictional Tax Depreciation - 12/31/2025 - ID	S	16,899,285	0	0	0	0	16,899,285	0	0	0	0	
Jurisdictional Tax Depreciation - 12/31/2025 - OTHER	S	116,245	0	0	0	0	0	0	0	116,245	0	
Jurisdictional Tax Depreciation - 12/31/2025 - OR	S	66,398,008	0	66,398,008	0	0	0	0	0	0	0	
Jurisdictional Tax Depreciation - 12/31/2025 - SG	SG	817,883,519	11,261,170	219,881,090	61,244,980	367,068,684	45,754,458	112,673,136	0	0	0	
Jurisdictional Tax Depreciation - 12/31/2025 - SG-CAGE	SG	96,044,337	1,322,403	25,820,710	7,192,019	43,104,999	5,372,961	13,231,244	0	0	0	
Jurisdictional Tax Depreciation - 12/31/2025 - SG-CAGW	SG	32,497,425	447,446	8,736,659	2,433,481	14,584,946	1,817,988	4,476,905	0	0	0	
Jurisdictional Tax Depreciation - 12/31/2025 - SO	SO	177,039,484	4,644,468	48,553,903	12,952,868	78,720,324	9,652,923	22,514,997	0	0	0	
Jurisdictional Tax Depreciation - 12/31/2025 - UT	S	136,402,474	0	0	0	136,402,474	0	0	0	0	0	
Jurisdictional Tax Depreciation - 12/31/2025 - WA	S	18,205,662	0	0	18,205,662	0	0	0	0	0	0	
Jurisdictional Tax Depreciation - 12/31/2025 - WY	S	22,381,096	0	0	0	0	0	22,381,096	0	0	0	
Jurisdictional Tax Depreciation - 12/31/2025 - TOTAL		1,404,792,824	38,600,776	369,390,370	102,029,010	639,881,427	79,497,615	175,277,379	0	116,245	0	
Current Total M Difference		1,404,792,824	38,600,776	369,390,370	102,029,010	639,881,427	79,497,615	175,277,379	0	116,245	0	
Tax Depr factor		100.0000%	2.7478%	26.2950%	7.2629%	45.5499%	5.6590%	12.4771%	0.0000%	0.0083%	0.0000%	

Pro Forma Factors December 31, 2025
Oregon General Rate Case - December 2025
COINCIDENTAL PEAKS

FORECAST LOADS (CP)

			Non-FERC						FERC	
Month	Day	Hour	CA	OR	WA	UT	ID	WY	UT	Total
Jan-25	14	8	148	2,814	848	3,773	487	1,255	30	9,355
Feb-25	24	8	137	2,631	751	3,745	451	1,258	27	8,999
Mar-25	4	7	128	2,502	671	3,640	464	1,233	27	8,664
Apr-25	15	7	125	2,365	545	3,321	408	1,149	28	7,942
May-25	30	16	109	1,993	612	4,069	594	1,120	27	8,524
Jun-25	27	16	130	2,319	682	5,112	772	1,245	28	10,289
Jul-25	21	16	143	2,745	799	5,579	781	1,256	27	11,330
Aug-25	18	16	133	2,591	796	5,418	604	1,246	29	10,816
Sep-25	9	16	111	2,093	596	4,940	550	1,194	29	9,513
Oct-25	28	18	102	2,190	602	3,611	426	1,187	28	8,147
Nov-25	20	8	137	2,580	738	3,835	430	1,215	28	8,963
Dec-25	23	18	135	2,634	752	4,180	512	1,241	30	9,485
			1,537	29,457	8,392	51,225	6,477	14,601	339	112,028

- (less)

Adjustments for Curtailments, Buy-Throughs and Load No Longer Served (Reductions to Load)

			Non-FERC						FERC	
Month	Day	Hour	CA	OR	WA	UT	ID	WY	UT	Total
Jan-25	14	8	-	-	-	0	-	-	30	30
Feb-25	24	8	-	-	-	15	-	-	27	43
Mar-25	4	7	-	-	-	3	-	-	27	30
Apr-25	15	7	-	-	-	80	-	-	28	108
May-25	30	16	-	-	-	456	-	-	27	482
Jun-25	27	16	-	-	-	505	180	-	28	714
Jul-25	21	16	-	-	-	523	180	-	27	730
Aug-25	18	16	-	-	-	526	180	-	29	735
Sep-25	9	16	-	-	-	451	-	-	29	480
Oct-25	28	18	-	-	-	59	-	-	28	87
Nov-25	20	8	-	-	-	34	-	-	28	63
Dec-25	23	18	-	-	-	-	-	-	30	30
			-	-	-	2,653	541	-	339	3,533

= equals

COINCIDENTAL PEAK SERVED FROM COMPANY RESOURCES

			Non-FERC						FERC	
Month	Day	Hour	CA	OR	WA	UT	ID	WY	UT	Total
Jan-25	14	8	148	2,814	848	3,773	487	1,255	-	9,325
Feb-25	24	8	137	2,631	751	3,730	451	1,258	-	8,957
Mar-25	4	7	128	2,502	671	3,637	464	1,233	-	8,634
Apr-25	15	7	125	2,365	545	3,242	408	1,149	-	7,834
May-25	30	16	109	1,993	612	3,613	594	1,120	-	8,041
Jun-25	27	16	130	2,319	682	4,607	592	1,245	-	9,576
Jul-25	21	16	143	2,745	799	5,056	600	1,256	-	10,600
Aug-25	18	16	133	2,591	796	4,892	423	1,246	-	10,081
Sep-25	9	16	111	2,093	596	4,489	550	1,194	-	9,033
Oct-25	28	18	102	2,190	602	3,552	426	1,187	-	8,060
Nov-25	20	8	137	2,580	738	3,801	430	1,215	-	8,900
Dec-25	23	18	135	2,634	752	4,180	512	1,241	-	9,454
			1,537	29,457	8,392	48,573	5,936	14,601	-	108,495

+ plus

Adjustments for Ancillary Services Contracts including Reserves and Direct Access (Additions to Load)

			Non-FERC						FERC	
Month	Day	Hour	CA	OR	WA	UT	ID	WY	UT	Total
Jan-25	14	8	-	-	-	30	-	-	-	30
Feb-25	24	8	-	-	-	27	-	-	-	27
Mar-25	4	7	-	-	-	27	-	-	-	27
Apr-25	15	7	-	-	-	28	-	-	-	28
May-25	30	16	-	-	-	27	-	-	-	27
Jun-25	27	16	-	-	-	28	-	-	-	28
Jul-25	21	16	-	-	-	27	-	-	-	27
Aug-25	18	16	-	-	-	29	-	-	-	29
Sep-25	9	16	-	-	-	29	-	-	-	29
Oct-25	28	18	-	-	-	28	-	-	-	28
Nov-25	20	8	-	-	-	28	-	-	-	28
Dec-25	23	18	-	-	-	30	-	-	-	30
			-	-	-	339	-	-	-	339

= equals

LOADS FOR JURISDICTIONAL ALLOCATION (CP)

			Non-FERC						FERC	
Month	Day	Hour	CA	OR	WA	UT	ID	WY	UT	Total
Jan-25	14	8	148	2,814	848	3,803	487	1,255	-	9,355
Feb-25	24	8	137	2,631	751	3,757	451	1,258	-	8,984
Mar-25	4	7	128	2,502	671	3,664	464	1,233	-	8,661
Apr-25	15	7	125	2,365	545	3,270	408	1,149	-	7,862
May-25	30	16	109	1,993	612	3,640	594	1,120	-	8,068
Jun-25	27	16	130	2,319	682	4,636	592	1,245	-	9,604
Jul-25	21	16	143	2,745	799	5,084	600	1,256	-	10,627
Aug-25	18	16	133	2,591	796	4,921	423	1,246	-	10,110
Sep-25	9	16	111	2,093	596	4,517	550	1,194	-	9,062
Oct-25	28	18	102	2,190	602	3,580	426	1,187	-	8,088
Nov-25	20	8	137	2,580	738	3,829	430	1,215	-	8,929
Dec-25	23	18	135	2,634	752	4,210	512	1,241	-	9,485
			1,537	29,457	8,392	48,912	5,936	14,601	-	108,834

Pro Forma Factors December 31, 2025
Oregon General Rate Case - December 2025
ENERGY

FORECAST LOADS (MWH)

		Non-FERC						FERC	
Year	Month	CA	OR	WA	UT	ID	WY	UT	Total
2025	1	74,830	1,517,220	431,930	2,498,000	311,320	855,540.00	20,241	5,709,081
2025	2	64,410	1,349,420	364,080	2,235,170	269,360	776,660.00	17,734	5,076,834
2025	3	65,280	1,402,540	353,420	2,306,090	278,220	815,670.00	20,863	5,242,083
2025	4	63,210	1,307,610	320,140	2,213,190	255,340	777,260.00	20,436	4,957,186
2025	5	69,640	1,331,390	330,050	2,338,820	341,540	793,380.00	20,292	5,225,112
2025	6	73,470	1,366,990	341,550	2,640,160	422,390	801,240.00	19,568	5,665,368
2025	7	81,060	1,564,170	405,410	3,107,940	501,170	842,610.00	20,442	6,522,802
2025	8	76,720	1,546,530	396,650	3,001,120	399,100	829,940.00	20,937	6,270,997
2025	9	64,670	1,378,810	345,730	2,521,920	315,580	776,320.00	20,235	5,423,265
2025	10	59,430	1,368,830	351,610	2,366,850	275,820	798,100.00	20,890	5,241,530
2025	11	63,450	1,452,050	379,490	2,384,380	253,260	794,890.00	20,513	5,348,033
2025	12	73,950	1,617,670	434,460	2,567,740	305,440	842,900.00	22,141	5,864,301
		830,120	17,203,230	4,454,520	30,181,380	3,928,540	9,704,510	244,292	66,546,592

- (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	UT	Total
2023	1	-	-	-	85,588	-	-	20,241	105,829
2023	2	-	-	-	94,259	-	-	17,734	111,993
2023	3	-	-	-	111,213	-	-	20,863	132,075
2023	4	-	-	-	108,305	-	-	20,436	128,741
2023	5	-	-	-	112,266	-	-	20,292	132,558
2023	6	-	-	-	112,130	-	-	19,568	131,698
2022	7	-	-	-	116,551	-	-	20,442	136,992
2022	8	-	-	-	117,121	-	-	20,937	138,058
2022	9	-	-	-	105,513	-	-	20,235	125,748
2022	10	-	-	-	104,943	-	-	20,890	125,834
2022	11	-	-	-	90,059	-	-	20,513	110,572
2022	12	-	-	-	74,274	-	-	22,141	96,415
		-	-	-	1,232,220	-	-	244,292	1,476,513

= equals

LOADS SERVED FROM COMPANY RESOURCES (NPC)

		Non-FERC						FERC	
Year	Month	CA	OR	WA	UT	ID	WY	UT	Total
2023	1	74,830	1,517,220	431,930	2,412,412	311,320	855,540	0	5,603,252
2023	2	64,410	1,349,420	364,080	2,140,911	269,360	776,660	(0)	4,964,841
2023	3	65,280	1,402,540	353,420	2,194,877	278,220	815,670	0	5,110,007
2023	4	63,210	1,307,610	320,140	2,104,885	255,340	777,260	(0)	4,828,445
2023	5	69,640	1,331,390	330,050	2,226,554	341,540	793,380	0	5,092,554
2023	6	73,470	1,366,990	341,550	2,528,030	422,390	801,240	0	5,533,670
2022	7	81,060	1,564,170	405,410	2,991,389	501,170	842,610	0	6,385,809
2022	8	76,720	1,546,530	396,650	2,883,999	399,100	829,940	0	6,132,939
2022	9	64,670	1,378,810	345,730	2,416,407	315,580	776,320	0	5,297,517
2022	10	59,430	1,368,830	351,610	2,261,907	275,820	798,100	0	5,115,697
2022	11	63,450	1,452,050	379,490	2,294,321	253,260	794,890	(0)	5,237,461
2022	12	73,950	1,617,670	434,460	2,493,466	305,440	842,900	0	5,767,886
		830,120	17,203,230	4,454,520	28,949,160	3,928,540	9,704,510	0	65,070,080

+ plus

Add: Resolute NTUA (UT) - Grossed up for Line Losses

		Non-FERC						FERC	
Year	Month	CA	OR	WA	UT	ID	WY	UT	Total
2023	1	-	-	-	20,241	-	-	-	20,241
2023	2	-	-	-	17,734	-	-	-	17,734
2023	3	-	-	-	20,863	-	-	-	20,863
2023	4	-	-	-	20,436	-	-	-	20,436
2023	5	-	-	-	20,292	-	-	-	20,292
2023	6	-	-	-	19,568	-	-	-	19,568
2022	7	-	-	-	20,442	-	-	-	20,442
2022	8	-	-	-	20,937	-	-	-	20,937
2022	9	-	-	-	20,235	-	-	-	20,235
2022	10	-	-	-	20,890	-	-	-	20,890
2022	11	-	-	-	20,513	-	-	-	20,513
2022	12	-	-	-	22,141	-	-	-	22,141
		-	-	-	244,292	-	-	-	244,292

= equals

LOADS FOR JURISDICTIONAL ALLOCATION (MWh)

		Non-FERC						FERC	
Year	Month	CA	OR	WA	UT	ID	WY	UT	Total
2023	1	74,830	1,517,220	431,930	2,432,653	311,320	855,540	0	5,623,493
2023	2	64,410	1,349,420	364,080	2,158,645	269,360	776,660	(0)	4,982,575
2023	3	65,280	1,402,540	353,420	2,215,740	278,220	815,670	0	5,130,870
2023	4	63,210	1,307,610	320,140	2,125,322	255,340	777,260	(0)	4,848,882
2023	5	69,640	1,331,390	330,050	2,246,847	341,540	793,380	0	5,112,847
2023	6	73,470	1,366,990	341,550	2,547,597	422,390	801,240	0	5,553,237
2022	7	81,060	1,564,170	405,410	3,011,831	501,170	842,610	0	6,406,251
2022	8	76,720	1,546,530	396,650	2,904,936	399,100	829,940	0	6,153,876
2022	9	64,670	1,378,810	345,730	2,436,642	315,580	776,320	0	5,317,752
2022	10	59,430	1,368,830	351,610	2,282,797	275,820	798,100	0	5,136,587
2022	11	63,450	1,452,050	379,490	2,314,834	253,260	794,890	(0)	5,257,974
2022	12	73,950	1,617,670	434,460	2,515,607	305,440	842,900	0	5,790,027
		830,120	17,203,230	4,454,520	29,193,452	3,928,540	9,704,510	0	65,314,372

Pro Forma Factors December 31, 2025
Oregon General Rate Case - December 2025

	CALIFORNIA	OREGON	WASHINGTON	UTAH	IDAHO	WYOMING	FERC		
Subtotal	830,120	17,203,230	4,454,520	29,193,452	3,928,540	9,704,510	0	**65,314,372**	**Ref Page 10.12**
System Energy Factor	1.271%	26.339%	6.820%	44.697%	6.015%	14.8582%	0.000%	100.00%	
Divisional Energy - Pacific	2.681%	55.564%	14.387%	0.000%	0.000%	27.3679%	0.000%	100.00%	
Divisional Energy - Utah	0.000%	0.000%	0.000%	84.981%	11.436%	3.5835%	0.000%	100.00%	
System Generation Factor	1.377%	26.884%	7.488%	44.880%	5.594%	13.7762%	0.000%	100.00%	
Divisional Generation - Pacific	2.879%	56.220%	15.659%	0.000%	0.000%	25.2408%	0.000%	100.00%	
Divisional Generation - Utah	0.000%	0.000%	0.000%	86.009%	10.721%	3.2698%	0.000%	100.00%	
System Capacity (kw)									
Accord	1,537	29,457	8,392	48,912	5,936	14,600.7	0	**108,834**	**Ref Page 10.11**
Modified Accord	1,537	29,457	8,392	48,912	5,936	14,600.7	0	**108,834**	**Ref Page 10.11**
Rolled-In	1,537	29,457	8,392	48,912	5,936	14,600.7	0	**108,834**	**Ref Page 10.11**
Rolled-In with Hydro Adj.	1,537	29,457	8,392	48,912	5,936	14,600.7	0	**108,834**	**Ref Page 10.11**
Rolled-In with Off-Sys Adj.	1,537	29,457	8,392	48,912	5,936	14,600.7	0	**108,834**	**Ref Page 10.11**
System Capacity Factor									
Accord	1.412%	27.066%	7.711%	44.941%	5.454%	13.4155%	0.000%	100.00%	
Modified Accord	1.412%	27.066%	7.711%	44.941%	5.454%	13.4155%	0.000%	100.00%	
Rolled-In	1.412%	27.066%	7.711%	44.941%	5.454%	13.4155%	0.000%	100.00%	
Rolled-In with Hydro Adj.	1.412%	27.066%	7.711%	44.941%	5.454%	13.4155%	0.000%	100.00%	
Rolled-In with Off-Sys Adj.	1.412%	27.066%	7.711%	44.941%	5.454%	13.4155%	0.000%	100.00%	
System Energy (kwh)									
Accord	830,120	17,203,230	4,454,520	29,193,452	3,928,540	9,704,510	0	65,314,372	
Modified Accord	830,120	17,203,230	4,454,520	29,193,452	3,928,540	9,704,510	0	65,314,372	
Rolled-In	830,120	17,203,230	4,454,520	29,193,452	3,928,540	9,704,510	0	65,314,372	
Rolled-In with Hydro Adj.	830,120	17,203,230	4,454,520	29,193,452	3,928,540	9,704,510	0	65,314,372	
Rolled-In with Off-Sys Adj.	830,120	17,203,230	4,454,520	29,193,452	3,928,540	9,704,510	0	65,314,372	
System Energy Factor									
Accord	1.271%	26.339%	6.820%	44.697%	6.015%	14.8582%	0.000%	100.00%	
Modified Accord	1.271%	26.339%	6.820%	44.697%	6.015%	14.8582%	0.000%	100.00%	
Rolled-In	1.271%	26.339%	6.820%	44.697%	6.015%	14.8582%	0.000%	100.00%	
Rolled-In with Hydro Adj.	1.271%	26.339%	6.820%	44.697%	6.015%	14.8582%	0.000%	100.00%	
Rolled-In with Off-Sys Adj.	1.271%	26.339%	6.820%	44.697%	6.015%	14.8582%	0.000%	100.00%	
System Generation Factor									
Accord	1.377%	26.884%	7.488%	44.880%	5.594%	13.7762%	0.000%	100.00%	
Modified Accord	1.377%	26.884%	7.488%	44.880%	5.594%	13.7762%	0.000%	100.00%	
Rolled-In	1.377%	26.884%	7.488%	44.880%	5.594%	13.7762%	0.000%	100.00%	
Rolled-In with Hydro Adj.	1.377%	26.884%	7.488%	44.880%	5.594%	13.7762%	0.000%	100.00%	
Rolled-In with Off-Sys Adj.	1.377%	26.884%	7.488%	44.880%	5.594%	13.7762%	0.000%	100.00%	

B1. REVENUE

PACIFICORP

Electric Operations Revenue (Actuals)
Sum of Range: 07/2022 - 06/2023
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Balance	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4118000	GAINS-DISP OF ALLOW	0	SO2 ALLOWANCE	SE	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	-
4118000 Total					**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**0**
4211000	GAIN DISPOS PROP	554000	GAIN ON DISPOSITION OF PROPERTY	OR	81	-	81	-	-	-	-	-	-
4211000	GAIN DISPOS PROP	554000	GAIN ON DISPOSITION OF PROPERTY	SO	(477)	(13)	(131)	(35)	(61)	(212)	(26)	(0)	-
4211000 Total					**(396)**	**(13)**	**(50)**	**(35)**	**(61)**	**(212)**	**(26)**	**(0)**	**0**
4212000	LOSS DISPOS PROP	554100	LOSS - SALE OF ASSETS	WYP	0	-	-	-	0	-	-	-	-
4212000 Total					**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
4401000	RESIDENTIAL SALES	301100	RESIDENTIAL SALES	CA	54,245	54,245	-	-	-	-	-	-	-
4401000	RESIDENTIAL SALES	301100	RESIDENTIAL SALES	IDU	97,093	-	-	-	-	-	97,093	-	-
4401000	RESIDENTIAL SALES	301100	RESIDENTIAL SALES	OR	726,987	-	726,987	-	-	-	-	-	-
4401000	RESIDENTIAL SALES	301100	RESIDENTIAL SALES	UT	919,551	-	-	-	-	919,551	-	-	-
4401000	RESIDENTIAL SALES	301100	RESIDENTIAL SALES	WA	194,540	-	-	194,540	-	-	-	-	-
4401000	RESIDENTIAL SALES	301100	RESIDENTIAL SALES	WYP	105,187	-	-	-	105,187	-	-	-	-
4401000	RESIDENTIAL SALES	301100	RESIDENTIAL SALES	WYU	13,613	-	-	-	13,613	-	-	-	-
4401000	RESIDENTIAL SALES	301106	Residential-Alt Revenue Program Adjs	WA	13,113	-	-	13,113	-	-	-	-	-
4401000	RESIDENTIAL SALES	301107	Residential Revenue Acctg Adjustments	CA	(750)	(750)	-	-	-	-	-	-	-
4401000	RESIDENTIAL SALES	301107	Residential Revenue Acctg Adjustments	IDU	573	-	-	-	-	-	573	-	-
4401000	RESIDENTIAL SALES	301107	Residential Revenue Acctg Adjustments	OR	(1,056)	-	(1,056)	-	-	-	-	-	-
4401000	RESIDENTIAL SALES	301107	Residential Revenue Acctg Adjustments	UT	473	-	-	-	-	473	-	-	-
4401000	RESIDENTIAL SALES	301107	Residential Revenue Acctg Adjustments	WA	(6,574)	-	-	(6,574)	-	-	-	-	-
4401000	RESIDENTIAL SALES	301107	Residential Revenue Acctg Adjustments	WYP	15	-	-	-	15	-	-	-	-
4401000	RESIDENTIAL SALES	301108	Residential Revenue Adj - Deferred NPC M	UT	24,767	-	-	-	-	24,767	-	-	-
4401000	RESIDENTIAL SALES	301108	Residential Revenue Adj - Deferred NPC M	WA	486	-	-	486	-	-	-	-	-
4401000	RESIDENTIAL SALES	301108	Residential Revenue Adj - Deferred NPC M	WYP	(301)	-	-	-	(301)	-	-	-	-
4401000	RESIDENTIAL SALES	301109	UNBILLED REVENUE - RESIDENTIAL	CA	(13)	(13)	-	-	-	-	-	-	-
4401000	RESIDENTIAL SALES	301109	UNBILLED REVENUE - RESIDENTIAL	IDU	(1,385)	-	-	-	-	-	(1,385)	-	-
4401000	RESIDENTIAL SALES	301109	UNBILLED REVENUE - RESIDENTIAL	OR	504	-	504	-	-	-	-	-	-
4401000	RESIDENTIAL SALES	301109	UNBILLED REVENUE - RESIDENTIAL	UT	(6,100)	-	-	-	-	(6,100)	-	-	-
4401000	RESIDENTIAL SALES	301109	UNBILLED REVENUE - RESIDENTIAL	WA	2,688	-	-	2,688	-	-	-	-	-
4401000	RESIDENTIAL SALES	301109	UNBILLED REVENUE - RESIDENTIAL	WYP	(1,184)	-	-	-	(1,184)	-	-	-	-
4401000	RESIDENTIAL SALES	301109	UNBILLED REVENUE - RESIDENTIAL	WYU	(116)	-	-	-	(116)	-	-	-	-
4401000	RESIDENTIAL SALES	301110	Residential - Income Tax Deferral Adjs	CA	775	775	-	-	-	-	-	-	-
4401000	RESIDENTIAL SALES	301110	Residential - Income Tax Deferral Adjs	OR	1,495	-	1,495	-	-	-	-	-	-
4401000	RESIDENTIAL SALES	301110	Residential - Income Tax Deferral Adjs	WA	811	-	-	811	-	-	-	-	-
4401000	RESIDENTIAL SALES	301110	Residential - Income Tax Deferral Adjs	WYP	247	-	-	-	247	-	-	-	-
4401000	RESIDENTIAL SALES	301111	Residential-OR Corp Act Tax Rev Adj	OTHER	1,899	-	-	-	-	-	-	-	1,899
4401000	RESIDENTIAL SALES	301112	Residential - Customer Bill Credits	IDU	(234)	-	-	-	-	-	(234)	-	-
4401000	RESIDENTIAL SALES	301112	Residential - Customer Bill Credits	OR	(1,624)	-	(1,624)	-	-	-	-	-	-
4401000	RESIDENTIAL SALES	301112	Residential - Customer Bill Credits	UT	(3,293)	-	-	-	-	(3,293)	-	-	-
4401000	RESIDENTIAL SALES	301112	Residential - Customer Bill Credits	WA	(675)	-	-	(675)	-	-	-	-	-
4401000	RESIDENTIAL SALES	301165	Solar Feed-In Revenue - Residential	OTHER	2,027	-	-	-	-	-	-	-	2,027
4401000	RESIDENTIAL SALES	301168	Community Solar Revenue-Residential	OTHER	249	-	-	-	-	-	-	-	249
4401000	RESIDENTIAL SALES	301170	DSM Revenue - Residential	OTHER	49,501	-	-	-	-	-	-	-	49,501
4401000	RESIDENTIAL SALES	301171	DSM Revenue - Residential Cat 2 Gen Svc	OTHER	46	-	-	-	-	-	-	-	46
4401000	RESIDENTIAL SALES	301180	Blue Sky Revenue Residential	OTHER	4,054	-	-	-	-	-	-	-	4,054
4401000	RESIDENTIAL SALES	301190	Other Cust Retail Revenue-Residential	OTHER	875	-	-	-	-	-	-	-	875
4401000 Total					**2,192,507**	**54,257**	**726,306**	**204,388**	**117,460**	**935,398**	**96,047**	**0**	**58,651**
4421000	COMMERCIAL SALES	301200	COMMERCIAL SALES	CA	34,081	34,081	-	-	-	-	-	-	-
4421000	COMMERCIAL SALES	301200	COMMERCIAL SALES	IDU	49,917	-	-	-	-	-	49,917	-	-
4421000	COMMERCIAL SALES	301200	COMMERCIAL SALES	OR	518,131	-	518,131	-	-	-	-	-	-
4421000	COMMERCIAL SALES	301200	COMMERCIAL SALES	UT	811,650	-	-	-	-	811,650	-	-	-
4421000	COMMERCIAL SALES	301200	COMMERCIAL SALES	WA	150,434	-	-	150,434	-	-	-	-	-
4421000	COMMERCIAL SALES	301200	COMMERCIAL SALES	WYP	112,411	-	-	-	112,411	-	-	-	-
4421000	COMMERCIAL SALES	301200	COMMERCIAL SALES	WYU	11,270	-	-	-	11,270	-	-	-	-
4421000	COMMERCIAL SALES	301206	Commercial-Alt Revenue Program Adjs	WA	(17,048)	-	-	(17,048)	-	-	-	-	-
4421000	COMMERCIAL SALES	301207	Commercial Revenue Acctg Adjustments	CA	(404)	(404)	-	-	-	-	-	-	-
4421000	COMMERCIAL SALES	301207	Commercial Revenue Acctg Adjustments	IDU	337	-	-	-	-	-	337	-	-
4421000	COMMERCIAL SALES	301207	Commercial Revenue Acctg Adjustments	OR	858	-	858	-	-	-	-	-	-

PACIFICORP

Electric Operations Revenue (Actuals)
Sum of Range: 07/2022 - 06/2023
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Balance	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4421000	COMMERCIAL SALES	301207	Commercial Revenue Acctg Adjustments	UT	1,270	-	-	-	-	1,270	-	-	-
4421000	COMMERCIAL SALES	301207	Commercial Revenue Acctg Adjustments	WA	(2,155)	-	-	(2,155)	-	-	-	-	-
4421000	COMMERCIAL SALES	301207	Commercial Revenue Acctg Adjustments	WYP	20	-	-	-	20	-	-	-	-
4421000	COMMERCIAL SALES	301208	Commercial Revenue Adj - Deferred NPC Me	UT	30,405	-	-	-	-	30,405	-	-	-
4421000	COMMERCIAL SALES	301208	Commercial Revenue Adj - Deferred NPC Me	WA	446	-	-	446	-	-	-	-	-
4421000	COMMERCIAL SALES	301208	Commercial Revenue Adj - Deferred NPC Me	WYP	(399)	-	-	-	(399)	-	-	-	-
4421000	COMMERCIAL SALES	301209	UNBILLED REVENUE - COMMERCIAL	CA	(201)	(201)	-	-	-	-	-	-	-
4421000	COMMERCIAL SALES	301209	UNBILLED REVENUE - COMMERCIAL	IDU	(676)	-	-	-	-	-	(676)	-	-
4421000	COMMERCIAL SALES	301209	UNBILLED REVENUE - COMMERCIAL	OR	12,011	-	12,011	-	-	-	-	-	-
4421000	COMMERCIAL SALES	301209	UNBILLED REVENUE - COMMERCIAL	UT	4,200	-	-	-	-	4,200	-	-	-
4421000	COMMERCIAL SALES	301209	UNBILLED REVENUE - COMMERCIAL	WA	801	-	-	801	-	-	-	-	-
4421000	COMMERCIAL SALES	301209	UNBILLED REVENUE - COMMERCIAL	WYP	(763)	-	-	-	(763)	-	-	-	-
4421000	COMMERCIAL SALES	301209	UNBILLED REVENUE - COMMERCIAL	WYU	(259)	-	-	-	(259)	-	-	-	-
4421000	COMMERCIAL SALES	301210	Commercial - Income Tax Deferral Adjs	CA	470	470	-	-	-	-	-	-	-
4421000	COMMERCIAL SALES	301210	Commercial - Income Tax Deferral Adjs	OR	1,402	-	1,402	-	-	-	-	-	-
4421000	COMMERCIAL SALES	301210	Commercial - Income Tax Deferral Adjs	WA	749	-	-	749	-	-	-	-	-
4421000	COMMERCIAL SALES	301210	Commercial - Income Tax Deferral Adjs	WYP	327	-	-	-	327	-	-	-	-
4421000	COMMERCIAL SALES	301211	Commercial-OR Corp Act Tax Alt Rev Adj	OTHER	1,425	-	-	-	-	-	-	-	1,425
4421000	COMMERCIAL SALES	301212	Commercial - Customer Bill Credits	IDU	(24)	-	-	-	-	-	(24)	-	-
4421000	COMMERCIAL SALES	301212	Commercial - Customer Bill Credits	OR	(198)	-	(198)	-	-	-	-	-	-
4421000	COMMERCIAL SALES	301212	Commercial - Customer Bill Credits	UT	(283)	-	-	-	-	(283)	-	-	-
4421000	COMMERCIAL SALES	301212	Commercial - Customer Bill Credits	WA	(67)	-	-	(67)	-	-	-	-	-
4421000	COMMERCIAL SALES	301265	Solar Feed-In Revenue - Commercial	OTHER	1,852	-	-	-	-	-	-	-	1,852
4421000	COMMERCIAL SALES	301268	Community Solar Revenue-Commercial	OTHER	181	-	-	-	-	-	-	-	181
4421000	COMMERCIAL SALES	301270	DSM Revenue - Commercial	OTHER	46,428	-	-	-	-	-	-	-	46,428
4421000	COMMERCIAL SALES	301271	DSM Revenue - Small Commercial	OTHER	3,331	-	-	-	-	-	-	-	3,331
4421000	COMMERCIAL SALES	301272	DSM Revenue - Large Commercial	OTHER	136	-	-	-	-	-	-	-	136
4421000	COMMERCIAL SALES	301280	Blue Sky Revenue - Commercial	OTHER	2,136	-	-	-	-	-	-	-	2,136
4421000	COMMERCIAL SALES	301290	Other Cust Retail Revenue-Commercial	OTHER	936	-	-	-	-	-	-	-	936
4421000 Total					**1,775,138**	**33,945**	**532,204**	**133,159**	**122,607**	**847,242**	**49,554**	**0**	**56,425**
4422000	IND SLS/EXCL IRRIG	301300	INDUSTRIAL SALES (EXCLUDING IRRIGATION)	CA	6,650	6,650	-	-	-	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301300	INDUSTRIAL SALES (EXCLUDING IRRIGATION)	IDU	19,664	-	-	-	-	-	19,664	-	-
4422000	IND SLS/EXCL IRRIG	301300	INDUSTRIAL SALES (EXCLUDING IRRIGATION)	OR	111,774	-	111,774	-	-	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301300	INDUSTRIAL SALES (EXCLUDING IRRIGATION)	UT	331,877	-	-	-	-	331,877	-	-	-
4422000	IND SLS/EXCL IRRIG	301300	INDUSTRIAL SALES (EXCLUDING IRRIGATION)	WA	54,890	-	-	54,890	-	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301300	INDUSTRIAL SALES (EXCLUDING IRRIGATION)	WYP	316,541	-	-	-	316,541	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301300	INDUSTRIAL SALES (EXCLUDING IRRIGATION)	WYU	63,655	-	-	-	63,655	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301304	SPECIAL CONTRACTS-SITUS	IDU	90,257	-	-	-	-	-	90,257	-	-
4422000	IND SLS/EXCL IRRIG	301304	SPECIAL CONTRACTS-SITUS	UT	162,495	-	-	-	-	162,495	-	-	-
4422000	IND SLS/EXCL IRRIG	301306	Industrial-Alt Revenue Program Adjs	WA	(798)	-	-	(798)	-	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301307	Industrial Revenue Acctg Adjustments	CA	(60)	(60)	-	-	-	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301307	Industrial Revenue Acctg Adjustments	IDU	119	-	-	-	-	-	119	-	-
4422000	IND SLS/EXCL IRRIG	301307	Industrial Revenue Acctg Adjustments	OR	354	-	354	-	-	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301307	Industrial Revenue Acctg Adjustments	UT	449	-	-	-	-	449	-	-	-
4422000	IND SLS/EXCL IRRIG	301307	Industrial Revenue Acctg Adjustments	WA	791	-	-	791	-	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301307	Industrial Revenue Acctg Adjustments	WYP	89	-	-	-	89	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301308	Industrial Revenue Adj - Deferred NPC Me	UT	24,160	-	-	-	-	24,160	-	-	-
4422000	IND SLS/EXCL IRRIG	301308	Industrial Revenue Adj - Deferred NPC Me	WA	222	-	-	222	-	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301308	Industrial Revenue Adj - Deferred NPC Me	WYP	(1,779)	-	-	-	(1,779)	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301309	UNBILLED REVENUE - INDUSTRIAL	CA	(104)	(104)	-	-	-	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301309	UNBILLED REVENUE - INDUSTRIAL	IDU	229	-	-	-	-	-	229	-	-
4422000	IND SLS/EXCL IRRIG	301309	UNBILLED REVENUE - INDUSTRIAL	OR	(403)	-	(403)	-	-	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301309	UNBILLED REVENUE - INDUSTRIAL	UT	(10,000)	-	-	-	-	(10,000)	-	-	-
4422000	IND SLS/EXCL IRRIG	301309	UNBILLED REVENUE - INDUSTRIAL	WA	668	-	-	668	-	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301309	UNBILLED REVENUE - INDUSTRIAL	WYP	(4,136)	-	-	-	(4,136)	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301309	UNBILLED REVENUE - INDUSTRIAL	WYU	642	-	-	-	642	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301310	Industrial - Income Tax Deferral Adjs	CA	119	119	-	-	-	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301310	Industrial - Income Tax Deferral Adjs	OR	379	-	379	-	-	-	-	-	-

PACIFICORP

Electric Operations Revenue (Actuals)
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(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Balance	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4422000	IND SLS/EXCL IRRIG	301310	Industrial - Income Tax Deferral Adjs	WA	393	-	-	393	-	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301310	Industrial - Income Tax Deferral Adjs	WYP	1,457	-	-	-	1,457	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301311	Industrial-OR Corp Act Tax Rev Adj	OTHER	308	-	-	-	-	-	-	-	308
4422000	IND SLS/EXCL IRRIG	301312	Industrial - Customer Bill Credits	IDU	(1)	-	-	-	-	-	(1)	-	-
4422000	IND SLS/EXCL IRRIG	301312	Industrial - Customer Bill Credits	OR	(3)	-	(3)	-	-	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301312	Industrial - Customer Bill Credits	UT	(11)	-	-	-	-	(11)	-	-	-
4422000	IND SLS/EXCL IRRIG	301312	Industrial - Customer Bill Credits	WA	(1)	-	-	(1)	-	-	-	-	-
4422000	IND SLS/EXCL IRRIG	301365	Solar Feed-In Revenue - Industrial	OTHER	543	-	-	-	-	-	-	-	543
4422000	IND SLS/EXCL IRRIG	301368	Community Solar Revenue-Industrial	OTHER	47	-	-	-	-	-	-	-	47
4422000	IND SLS/EXCL IRRIG	301370	DSM Revenue - Industrial	OTHER	19,372	-	-	-	-	-	-	-	19,372
4422000	IND SLS/EXCL IRRIG	301371	DSM Revenue - Small Industrial	OTHER	729	-	-	-	-	-	-	-	729
4422000	IND SLS/EXCL IRRIG	301372	DSM Revenue - Large Industrial	OTHER	2,726	-	-	-	-	-	-	-	2,726
4422000	IND SLS/EXCL IRRIG	301380	Blue Sky Revenue - Industrial	OTHER	642	-	-	-	-	-	-	-	642
4422000	IND SLS/EXCL IRRIG	301390	Other Cust Retail Revenue-Industrial	OTHER	747	-	-	-	-	-	-	-	747
4422000 Total					**1,195,691**	**6,605**	**112,100**	**56,165**	**376,470**	**508,971**	**110,267**	**0**	**25,114**
4423000	INDUST SALES-IRRIG	301450	INDUSTRIAL SALES - IRRIGATION	CA	12,536	12,536	-	-	-	-	-	-	-
4423000	INDUST SALES-IRRIG	301450	INDUSTRIAL SALES - IRRIGATION	IDU	58,616	-	-	-	-	-	58,616	-	-
4423000	INDUST SALES-IRRIG	301450	INDUSTRIAL SALES - IRRIGATION	OR	21,229	-	21,229	-	-	-	-	-	-
4423000	INDUST SALES-IRRIG	301450	INDUSTRIAL SALES - IRRIGATION	UT	17,504	-	-	-	-	17,504	-	-	-
4423000	INDUST SALES-IRRIG	301450	INDUSTRIAL SALES - IRRIGATION	WA	16,160	-	-	16,160	-	-	-	-	-
4423000	INDUST SALES-IRRIG	301450	INDUSTRIAL SALES - IRRIGATION	WYP	2,118	-	-	-	2,118	-	-	-	-
4423000	INDUST SALES-IRRIG	301450	INDUSTRIAL SALES - IRRIGATION	WYU	597	-	-	-	597	-	-	-	-
4423000	INDUST SALES-IRRIG	301453	Irrigation - Customer Bill Credits	IDU	(4)	-	-	-	-	-	(4)	-	-
4423000	INDUST SALES-IRRIG	301453	Irrigation - Customer Bill Credits	OR	(11)	-	(11)	-	-	-	-	-	-
4423000	INDUST SALES-IRRIG	301453	Irrigation - Customer Bill Credits	UT	(3)	-	-	-	-	(3)	-	-	-
4423000	INDUST SALES-IRRIG	301453	Irrigation - Customer Bill Credits	WA	(15)	-	-	(15)	-	-	-	-	-
4423000	INDUST SALES-IRRIG	301454	Irrigation-OR Corp Act Tax Rev Adj	OTHER	85	-	-	-	-	-	-	-	85
4423000	INDUST SALES-IRRIG	301455	Irrigation - Income Tax Deferral Adjs	CA	206	206	-	-	-	-	-	-	-
4423000	INDUST SALES-IRRIG	301455	Irrigation - Income Tax Deferral Adjs	OR	57	-	57	-	-	-	-	-	-
4423000	INDUST SALES-IRRIG	301455	Irrigation - Income Tax Deferral Adjs	WA	80	-	-	80	-	-	-	-	-
4423000	INDUST SALES-IRRIG	301455	Irrigation - Income Tax Deferral Adjs	WYP	8	-	-	-	8	-	-	-	-
4423000	INDUST SALES-IRRIG	301456	Irrigation-Alt Revenue Program Adjs	WA	5	-	-	5	-	-	-	-	-
4423000	INDUST SALES-IRRIG	301457	Irrigation Revenue Acctg Adjustments	CA	(115)	(115)	-	-	-	-	-	-	-
4423000	INDUST SALES-IRRIG	301457	Irrigation Revenue Acctg Adjustments	IDU	412	-	-	-	-	-	412	-	-
4423000	INDUST SALES-IRRIG	301457	Irrigation Revenue Acctg Adjustments	OR	(5)	-	(5)	-	-	-	-	-	-
4423000	INDUST SALES-IRRIG	301457	Irrigation Revenue Acctg Adjustments	UT	14	-	-	-	-	14	-	-	-
4423000	INDUST SALES-IRRIG	301457	Irrigation Revenue Acctg Adjustments	WA	272	-	-	272	-	-	-	-	-
4423000	INDUST SALES-IRRIG	301457	Irrigation Revenue Acctg Adjustments	WYP	0	-	-	-	0	-	-	-	-
4423000	INDUST SALES-IRRIG	301458	Irrigation Revenue Adj - Deferred NPC Me	UT	799	-	-	-	-	799	-	-	-
4423000	INDUST SALES-IRRIG	301458	Irrigation Revenue Adj - Deferred NPC Me	WA	(84)	-	-	(84)	-	-	-	-	-
4423000	INDUST SALES-IRRIG	301458	Irrigation Revenue Adj - Deferred NPC Me	WYP	(9)	-	-	-	(9)	-	-	-	-
4423000	INDUST SALES-IRRIG	301459	UNBILLED REVENUE - IRRIGATION/FARM	CA	542	542	-	-	-	-	-	-	-
4423000	INDUST SALES-IRRIG	301459	UNBILLED REVENUE - IRRIGATION/FARM	IDU	232	-	-	-	-	-	232	-	-
4423000	INDUST SALES-IRRIG	301459	UNBILLED REVENUE - IRRIGATION/FARM	OR	2,066	-	2,066	-	-	-	-	-	-
4423000	INDUST SALES-IRRIG	301459	UNBILLED REVENUE - IRRIGATION/FARM	UT	(16)	-	-	-	-	(16)	-	-	-
4423000	INDUST SALES-IRRIG	301459	UNBILLED REVENUE - IRRIGATION/FARM	WA	(196)	-	-	(196)	-	-	-	-	-
4423000	INDUST SALES-IRRIG	301459	UNBILLED REVENUE - IRRIGATION/FARM	WYP	(53)	-	-	-	(53)	-	-	-	-
4423000	INDUST SALES-IRRIG	301459	UNBILLED REVENUE - IRRIGATION/FARM	WYU	(18)	-	-	-	(18)	-	-	-	-
4423000	INDUST SALES-IRRIG	301461	Unbilled Revenue-Irrigation Demand Charg	CA	(48)	(48)	-	-	-	-	-	-	-
4423000	INDUST SALES-IRRIG	301461	Unbilled Revenue-Irrigation Demand Charg	OR	151	-	151	-	-	-	-	-	-
4423000	INDUST SALES-IRRIG	301461	Unbilled Revenue-Irrigation Demand Charg	WA	(321)	-	-	(321)	-	-	-	-	-
4423000	INDUST SALES-IRRIG	301465	Solar Feed-In Revenue - Irrigation	OTHER	58	-	-	-	-	-	-	-	58
4423000	INDUST SALES-IRRIG	301468	Community Solar Revenue-Irrigation	OTHER	6	-	-	-	-	-	-	-	6
4423000	INDUST SALES-IRRIG	301470	DSM Revenue - Irrigation	OTHER	3,260	-	-	-	-	-	-	-	3,260
4423000	INDUST SALES-IRRIG	301480	Blue Sky Revenue - Irrigation	OTHER	4	-	-	-	-	-	-	-	4
4423000	INDUST SALES-IRRIG	301490	Other Cust Retail Revenue-Irrigation	OTHER	51	-	-	-	-	-	-	-	51
4423000 Total					**136,169**	**13,121**	**23,486**	**15,901**	**2,644**	**18,298**	**59,256**	**0**	**3,464**
4441000	PUB ST/HWY LIGHT	301600	PUBLIC STREET AND HIGHWAY LIGHTING	CA	388	388	-	-	-	-	-	-	-

PACIFICORP

Electric Operations Revenue (Actuals)
Sum of Range: 07/2022 - 06/2023
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Balance	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4441000	PUB ST/HWY LIGHT	301600	PUBLIC STREET AND HIGHWAY LIGHTING	IDU	473	-	-	-	-	-	473	-	-
4441000	PUB ST/HWY LIGHT	301600	PUBLIC STREET AND HIGHWAY LIGHTING	OR	4,998	-	4,998	-	-	-	-	-	-
4441000	PUB ST/HWY LIGHT	301600	PUBLIC STREET AND HIGHWAY LIGHTING	UT	6,067	-	-	-	-	6,067	-	-	-
4441000	PUB ST/HWY LIGHT	301600	PUBLIC STREET AND HIGHWAY LIGHTING	WA	653	-	-	653	-	-	-	-	-
4441000	PUB ST/HWY LIGHT	301600	PUBLIC STREET AND HIGHWAY LIGHTING	WYP	1,563	-	-	-	1,563	-	-	-	-
4441000	PUB ST/HWY LIGHT	301600	PUBLIC STREET AND HIGHWAY LIGHTING	WYU	271	-	-	-	271	-	-	-	-
4441000	PUB ST/HWY LIGHT	301607	Public St/Hwy Lights Rev Acctg Adjustmen	CA	(5)	(5)	-	-	-	-	-	-	-
4441000	PUB ST/HWY LIGHT	301607	Public St/Hwy Lights Rev Acctg Adjustmen	IDU	6	-	-	-	-	-	6	-	-
4441000	PUB ST/HWY LIGHT	301607	Public St/Hwy Lights Rev Acctg Adjustmen	OR	8	-	8	-	-	-	-	-	-
4441000	PUB ST/HWY LIGHT	301607	Public St/Hwy Lights Rev Acctg Adjustmen	UT	3	-	-	-	-	3	-	-	-
4441000	PUB ST/HWY LIGHT	301607	Public St/Hwy Lights Rev Acctg Adjustmen	WA	(23)	-	-	(23)	-	-	-	-	-
4441000	PUB ST/HWY LIGHT	301607	Public St/Hwy Lights Rev Acctg Adjustmen	WYU	0	-	-	-	0	-	-	-	-
4441000	PUB ST/HWY LIGHT	301608	Public St/Hwy Lgt Rev Adj-Def NPC Mech	UT	181	-	-	-	-	181	-	-	-
4441000	PUB ST/HWY LIGHT	301608	Public St/Hwy Lgt Rev Adj-Def NPC Mech	WA	1	-	-	1	-	-	-	-	-
4441000	PUB ST/HWY LIGHT	301608	Public St/Hwy Lgt Rev Adj-Def NPC Mech	WYP	(4)	-	-	-	(4)	-	-	-	-
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	(3)	-	-	-	-	-	(3)	-	-
4441000	PUB ST/HWY LIGHT	301609	UNBILLED REV - PUBLIC ST/HWY LIGHTING	OR	(85)	-	(85)	-	-	-	-	-	-
4441000	PUB ST/HWY LIGHT	301609	UNBILLED REV - PUBLIC ST/HWY LIGHTING	UT	(52)	-	-	-	-	(52)	-	-	-
4441000	PUB ST/HWY LIGHT	301609	UNBILLED REV - PUBLIC ST/HWY LIGHTING	WA	30	-	-	30	-	-	-	-	-
4441000	PUB ST/HWY LIGHT	301609	UNBILLED REV - PUBLIC ST/HWY LIGHTING	WYP	28	-	-	-	28	-	-	-	-
4441000	PUB ST/HWY LIGHT	301609	UNBILLED REV - PUBLIC ST/HWY LIGHTING	WYU	(10)	-	-	-	(10)	-	-	-	-
4441000	PUB ST/HWY LIGHT	301610	St&Hwy Light - Income Tax Deferral Adjs	CA	3	3	-	-	-	-	-	-	-
4441000	PUB ST/HWY LIGHT	301610	St&Hwy Light - Income Tax Deferral Adjs	OR	9	-	9	-	-	-	-	-	-
4441000	PUB ST/HWY LIGHT	301610	St&Hwy Light - Income Tax Deferral Adjs	WA	2	-	-	2	-	-	-	-	-
4441000	PUB ST/HWY LIGHT	301610	St&Hwy Light - Income Tax Deferral Adjs	WYP	3	-	-	-	3	-	-	-	-
4441000	PUB ST/HWY LIGHT	301611	St&Hwy Light-OR Corp Act Tax Rev Adj	OTHER	14	-	-	-	-	-	-	-	14
4441000	PUB ST/HWY LIGHT	301612	St&Hwy Light - Customer Bill Credits	IDU	(0)	-	-	-	-	-	(0)	-	-
4441000	PUB ST/HWY LIGHT	301612	St&Hwy Light - Customer Bill Credits	OR	(2)	-	(2)	-	-	-	-	-	-
4441000	PUB ST/HWY LIGHT	301612	St&Hwy Light - Customer Bill Credits	UT	(1)	-	-	-	-	(1)	-	-	-
4441000	PUB ST/HWY LIGHT	301665	Solar Feed-In Revenue - St/Hwy Lighting	OTHER	2	-	-	-	-	-	-	-	2
4441000	PUB ST/HWY LIGHT	301668	Community Solar Revenue-St/Hwy Lightg	OTHER	0	-	-	-	-	-	-	-	0
4441000	PUB ST/HWY LIGHT	301670	DSM Revenue - Street/Hwy Lighting	OTHER	336	-	-	-	-	-	-	-	336
4441000	PUB ST/HWY LIGHT	301690	Other Cust Retail Revenue-St/Hwy Lightg	OTHER	5	-	-	-	-	-	-	-	5
4441000 Total					**14,863**	**389**	**4,928**	**663**	**1,851**	**6,198**	**476**	**0**	**358**
4471000	ON-SYS WHOLE-FIRM	301443	ON SYS FIRM-UTAH FERC CUSTOMERS	FERC	14,258	-	-	-	-	-	-	14,258	-
4471000	ON-SYS WHOLE-FIRM	301445	On Sys Firm-Utah W/S Customers-Deferral	UT	(40)	-	-	-	-	(40)	-	-	-
4471000 Total					**14,219**	**0**	**0**	**0**	**0**	**(40)**	**0**	**14,258**	**0**
4471300	POST MERGER FIRM	301405	POST MERGER FIRM	SG	14,035	193	3,773	1,051	1,933	6,299	785	0	-
4471300 Total					**14,035**	**193**	**3,773**	**1,051**	**1,933**	**6,299**	**785**	**0**	**0**
4471400	S/T FIRM WHOLESALE	301406	SHORT-TERM FIRM WHOLESALE SALES	SG	318,409	4,384	85,602	23,843	43,865	142,903	17,813	0	-
4471400	S/T FIRM WHOLESALE	301409	TRADING SALES NETTED-EST.	SG	11	0	3	1	2	5	1	0	-
4471400	S/T FIRM WHOLESALE	301410	TRADING SALES NETTED	SG	(2,262)	(31)	(608)	(169)	(312)	(1,015)	(127)	(0)	-
4471400	S/T FIRM WHOLESALE	301411	BOOKOUT SALES NETTED	SG	(84,459)	(1,163)	(22,706)	(6,324)	(11,635)	(37,905)	(4,725)	(0)	-
4471400	S/T FIRM WHOLESALE	301412	BOOKOUT SALES NETTED-ESTIMATE	SG	7,356	101	1,978	551	1,013	3,301	412	0	-
4471400	S/T FIRM WHOLESALE	302751	I/C S-T Firm Wholesale Sales-Sierra Pac	SG	8	0	2	1	1	4	0	0	-
4471400	S/T FIRM WHOLESALE	302752	I/C S-T Firm Wholesale Sales-Nevada Pwr	SG	59	1	16	4	8	26	3	0	-
4471400	S/T FIRM WHOLESALE	302772	I/C Line Loss Trading Revenue-Nevada Pwr	SG	0	0	0	0	0	0	0	0	-
4471400	S/T FIRM WHOLESALE	303028	LINE LOSS W/S TRADING REVENUES	SG	31,329	431	8,422	2,346	4,316	14,060	1,753	0	-
4471400 Total					**270,451**	**3,724**	**72,708**	**20,252**	**37,258**	**121,379**	**15,130**	**0**	**0**
4472000	SLS FOR RESL-SURP	301419	ESTIMATED SALES FOR RESALE REVENUE	SG	(22,930)	(316)	(6,164)	(1,717)	(3,159)	(10,291)	(1,283)	(0)	-
4472000	SLS FOR RESL-SURP	303198	Non-ASC 606-WS NPC Rev-Derivativ (Disc)	SG	40,789	562	10,966	3,054	5,619	18,306	2,282	0	-
4472000	SLS FOR RESL-SURP	303199	Non-ASC 606-WS NPC Rev-Derivativ (Recl)	SG	(40,789)	(562)	(10,966)	(3,054)	(5,619)	(18,306)	(2,282)	(0)	-
4472000 Total					**(22,930)**	**(316)**	**(6,164)**	**(1,717)**	**(3,159)**	**(10,291)**	**(1,283)**	**(0)**	**0**
4476100	BOOKOUTS NETTED-GAIN	304101	BOOKOUTS NETTED-GAIN	SG	1,082	15	291	81	149	486	61	0	-
4476100	BOOKOUTS NETTED-GAIN	304102	BOOKOUTS NETTED-EST GAIN	SG	(107)	(1)	(29)	(8)	(15)	(48)	(6)	(0)	-
4476100 Total					**975**	**13**	**262**	**73**	**134**	**437**	**55**	**0**	**0**
4476200	TRADING NETTED-GAINS	304201	TRADING NETTED-GAINS	SG	27	0	7	2	4	12	2	0	-

PACIFICORP

Electric Operations Revenue (Actuals)
Sum of Range: 07/2022 - 06/2023
Allocation Method - Factor 2020 Protocol
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4476200 Total					**27**	**0**	**7**	**2**	**4**	**12**	**2**	**0**	**0**
4479000	TRANS SRVC	301428	TRANS SERV-UTAH FERC CUSTOMERS	FERC	99	-	-	-	-	-	-	99	-
4479000 Total					**99**	**0**	**0**	**0**	**0**	**0**	**0**	**99**	**0**
4501000	FORF DISC/INT-RES	301820	FORFEITED DISCOUNT REVENUE-RESIDENTIAL	CA	268	268	-	-	-	-	-	-	-
4501000	FORF DISC/INT-RES	301820	FORFEITED DISCOUNT REVENUE-RESIDENTIAL	IDU	302	-	-	-	-	-	302	-	-
4501000	FORF DISC/INT-RES	301820	FORFEITED DISCOUNT REVENUE-RESIDENTIAL	OR	4,146	-	4,146	-	-	-	-	-	-
4501000	FORF DISC/INT-RES	301820	FORFEITED DISCOUNT REVENUE-RESIDENTIAL	UT	3,850	-	-	-	-	3,850	-	-	-
4501000	FORF DISC/INT-RES	301820	FORFEITED DISCOUNT REVENUE-RESIDENTIAL	WA	16	-	-	16	-	-	-	-	-
4501000	FORF DISC/INT-RES	301820	FORFEITED DISCOUNT REVENUE-RESIDENTIAL	WYP	688	-	-	-	688	-	-	-	-
4501000	FORF DISC/INT-RES	301820	FORFEITED DISCOUNT REVENUE-RESIDENTIAL	WYU	74	-	-	-	74	-	-	-	-
4501000 Total					**9,345**	**268**	**4,146**	**16**	**762**	**3,850**	**302**	**0**	**0**
4502000	FORF DISC/INT-COMM	301821	FORFEITED DISCOUNT REVENUE-COMMERCIAL	CA	161	161	-	-	-	-	-	-	-
4502000	FORF DISC/INT-COMM	301821	FORFEITED DISCOUNT REVENUE-COMMERCIAL	IDU	34	-	-	-	-	-	34	-	-
4502000	FORF DISC/INT-COMM	301821	FORFEITED DISCOUNT REVENUE-COMMERCIAL	OR	1,192	-	1,192	-	-	-	-	-	-
4502000	FORF DISC/INT-COMM	301821	FORFEITED DISCOUNT REVENUE-COMMERCIAL	UT	1,112	-	-	-	-	1,112	-	-	-
4502000	FORF DISC/INT-COMM	301821	FORFEITED DISCOUNT REVENUE-COMMERCIAL	WA	1	-	-	1	-	-	-	-	-
4502000	FORF DISC/INT-COMM	301821	FORFEITED DISCOUNT REVENUE-COMMERCIAL	WYP	138	-	-	-	138	-	-	-	-
4502000	FORF DISC/INT-COMM	301821	FORFEITED DISCOUNT REVENUE-COMMERCIAL	WYU	42	-	-	-	42	-	-	-	-
4502000 Total					**2,680**	**161**	**1,192**	**1**	**180**	**1,112**	**34**	**0**	**0**
4503000	FORF DISC/INT-IND	301822	FORFEITED DISCOUNT REVENUE-INDUSTRIAL	CA	43	43	-	-	-	-	-	-	-
4503000	FORF DISC/INT-IND	301822	FORFEITED DISCOUNT REVENUE-INDUSTRIAL	IDU	58	-	-	-	-	-	58	-	-
4503000	FORF DISC/INT-IND	301822	FORFEITED DISCOUNT REVENUE-INDUSTRIAL	OR	234	-	234	-	-	-	-	-	-
4503000	FORF DISC/INT-IND	301822	FORFEITED DISCOUNT REVENUE-INDUSTRIAL	UT	335	-	-	-	-	335	-	-	-
4503000	FORF DISC/INT-IND	301822	FORFEITED DISCOUNT REVENUE-INDUSTRIAL	WA	2	-	-	2	-	-	-	-	-
4503000	FORF DISC/INT-IND	301822	FORFEITED DISCOUNT REVENUE-INDUSTRIAL	WYP	107	-	-	-	107	-	-	-	-
4503000	FORF DISC/INT-IND	301822	FORFEITED DISCOUNT REVENUE-INDUSTRIAL	WYU	9	-	-	-	9	-	-	-	-
4503000 Total					**787**	**43**	**234**	**2**	**115**	**335**	**58**	**0**	**0**
4504000	GOVT MUNI/ALL OTH	301823	FORFEITED DISCOUNT REVENUE-ALL OTHER	CA	0	0	-	-	-	-	-	-	-
4504000	GOVT MUNI/ALL OTH	301823	FORFEITED DISCOUNT REVENUE-ALL OTHER	IDU	(0)	-	-	-	-	-	(0)	-	-
4504000	GOVT MUNI/ALL OTH	301823	FORFEITED DISCOUNT REVENUE-ALL OTHER	OR	12	-	12	-	-	-	-	-	-
4504000	GOVT MUNI/ALL OTH	301823	FORFEITED DISCOUNT REVENUE-ALL OTHER	UT	15	-	-	-	-	15	-	-	-
4504000	GOVT MUNI/ALL OTH	301823	FORFEITED DISCOUNT REVENUE-ALL OTHER	WYP	14	-	-	-	14	-	-	-	-
4504000	GOVT MUNI/ALL OTH	301823	FORFEITED DISCOUNT REVENUE-ALL OTHER	WYU	(0)	-	-	-	(0)	-	-	-	-
4504000 Total					**40**	**0**	**12**	**0**	**13**	**15**	**(0)**	**0**	**0**
4511000	ACCOUNT SERV CHG	301825	MISC SERV REV-ACCT SERVICE CHARGE	CA	374	374	-	-	-	-	-	-	-
4511000	ACCOUNT SERV CHG	301825	MISC SERV REV-ACCT SERVICE CHARGE	IDU	95	-	-	-	-	-	95	-	-
4511000	ACCOUNT SERV CHG	301825	MISC SERV REV-ACCT SERVICE CHARGE	OR	903	-	903	-	-	-	-	-	-
4511000	ACCOUNT SERV CHG	301825	MISC SERV REV-ACCT SERVICE CHARGE	UT	3,025	-	-	-	-	3,025	-	-	-
4511000	ACCOUNT SERV CHG	301825	MISC SERV REV-ACCT SERVICE CHARGE	WA	36	-	-	36	-	-	-	-	-
4511000	ACCOUNT SERV CHG	301825	MISC SERV REV-ACCT SERVICE CHARGE	WYP	58	-	-	-	58	-	-	-	-
4511000	ACCOUNT SERV CHG	301825	MISC SERV REV-ACCT SERVICE CHARGE	WYU	4	-	-	-	4	-	-	-	-
4511000	ACCOUNT SERV CHG	301855	Misc Service Revenue - CSS (Non-FLT)	CA	13	13	-	-	-	-	-	-	-
4511000	ACCOUNT SERV CHG	301855	Misc Service Revenue - CSS (Non-FLT)	IDU	35	-	-	-	-	-	35	-	-
4511000	ACCOUNT SERV CHG	301855	Misc Service Revenue - CSS (Non-FLT)	OR	259	-	259	-	-	-	-	-	-
4511000	ACCOUNT SERV CHG	301855	Misc Service Revenue - CSS (Non-FLT)	UT	488	-	-	-	-	488	-	-	-
4511000	ACCOUNT SERV CHG	301855	Misc Service Revenue - CSS (Non-FLT)	WA	60	-	-	60	-	-	-	-	-
4511000	ACCOUNT SERV CHG	301855	Misc Service Revenue - CSS (Non-FLT)	WYP	49	-	-	-	49	-	-	-	-
4511000	ACCOUNT SERV CHG	301855	Misc Service Revenue - CSS (Non-FLT)	WYU	4	-	-	-	4	-	-	-	-
4511000 Total					**5,401**	**387**	**1,162**	**95**	**115**	**3,513**	**129**	**0**	**0**
4512000	TAMPER/RECONNECT	301826	TAMPERING/UNAUTHORIZED RECONNECTION CHGS	CA	0	0	-	-	-	-	-	-	-
4512000	TAMPER/RECONNECT	301826	TAMPERING/UNAUTHORIZED RECONNECTION CHGS	OR	4	-	4	-	-	-	-	-	-
4512000	TAMPER/RECONNECT	301826	TAMPERING/UNAUTHORIZED RECONNECTION CHGS	UT	0	-	-	-	-	0	-	-	-
4512000	TAMPER/RECONNECT	301826	TAMPERING/UNAUTHORIZED RECONNECTION CHGS	WYP	0	-	-	-	0	-	-	-	-
4512000 Total					**5**	**0**	**4**	**0**	**0**	**0**	**0**	**0**	**0**
4513000	OTHER	301828	OTHER	CA	5	5	-	-	-	-	-	-	-
4513000	OTHER	301828	OTHER	IDU	3	-	-	-	-	-	3	-	-
4513000	OTHER	301828	OTHER	OR	345	-	345	-	-	-	-	-	-
4513000	OTHER	301828	OTHER	UT	415	-	-	-	-	415	-	-	-

PACIFICORP

Electric Operations Revenue (Actuals)
Sum of Range: 07/2022 - 06/2023
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

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4513000	OTHER	301828	OTHER	WA	13	-	-	13	-	-	-	-	-
4513000	OTHER	301828	OTHER	WYP	301	-	-	-	301	-	-	-	-
4513000	OTHER	301828	OTHER	WYU	7	-	-	-	7	-	-	-	-
4513000	OTHER	301840	Miscellaneous Service Revenue	CA	12	12	-	-	-	-	-	-	-
4513000	OTHER	301840	Miscellaneous Service Revenue	IDU	58	-	-	-	-	-	58	-	-
4513000	OTHER	301840	Miscellaneous Service Revenue	OR	10	-	10	-	-	-	-	-	-
4513000	OTHER	301840	Miscellaneous Service Revenue	UT	543	-	-	-	-	543	-	-	-
4513000	OTHER	301840	Miscellaneous Service Revenue	WA	91	-	-	91	-	-	-	-	-
4513000 Total					**1,803**	**17**	**355**	**104**	**308**	**957**	**61**	**0**	**0**
4530000	SLS WATER & W PWR	358900	Sales of Water & Water Power	SG	5	0	1	0	1	2	0	0	-
4530000 Total					**5**	**0**	**1**	**0**	**1**	**2**	**0**	**0**	**0**
4541000	RENTS - COMMON	301860	RENT FROM ELEC PROP	CA	2	2	-	-	-	-	-	-	-
4541000	RENTS - COMMON	301860	RENT FROM ELEC PROP	IDU	1	-	-	-	-	-	1	-	-
4541000	RENTS - COMMON	301860	RENT FROM ELEC PROP	OR	835	-	835	-	-	-	-	-	-
4541000	RENTS - COMMON	301860	RENT FROM ELEC PROP	SG	997	14	268	75	137	448	56	0	-
4541000	RENTS - COMMON	301860	RENT FROM ELEC PROP	SO	3,325	87	912	243	423	1,478	181	0	-
4541000	RENTS - COMMON	301860	RENT FROM ELEC PROP	UT	1,451	-	-	-	-	1,451	-	-	-
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	301864	REVENUE - JOINT USE OF POLES	CA	499	499	-	-	-	-	-	-	-
4541000	RENTS - COMMON	301864	REVENUE - JOINT USE OF POLES	IDU	164	-	-	-	-	-	164	-	-
4541000	RENTS - COMMON	301864	REVENUE - JOINT USE OF POLES	OR	3,711	-	3,711	-	-	-	-	-	-
4541000	RENTS - COMMON	301864	REVENUE - JOINT USE OF POLES	UT	2,426	-	-	-	-	2,426	-	-	-
4541000	RENTS - COMMON	301864	REVENUE - JOINT USE OF POLES	WA	779	-	-	779	-	-	-	-	-
4541000	RENTS - COMMON	301864	REVENUE - JOINT USE OF POLES	WYP	319	-	-	-	319	-	-	-	-
4541000	RENTS - COMMON	301866	JOINT USE SANCTIONS & FINES REVENUE	OR	76	-	76	-	-	-	-	-	-
4541000	RENTS - COMMON	301866	JOINT USE SANCTIONS & FINES REVENUE	SG	0	0	0	0	0	0	0	0	-
4541000	RENTS - COMMON	301866	JOINT USE SANCTIONS & FINES REVENUE	UT	7	-	-	-	-	7	-	-	-
4541000	RENTS - COMMON	301866	JOINT USE SANCTIONS & FINES REVENUE	WYP	2	-	-	-	2	-	-	-	-
4541000	RENTS - COMMON	301867	JOINT USE PROGRAM REIMBURSE REVENUE	CA	2	2	-	-	-	-	-	-	-
4541000	RENTS - COMMON	301867	JOINT USE PROGRAM REIMBURSE REVENUE	IDU	0	-	-	-	-	-	0	-	-
4541000	RENTS - COMMON	301867	JOINT USE PROGRAM REIMBURSE REVENUE	OR	296	-	296	-	-	-	-	-	-
4541000	RENTS - COMMON	301867	JOINT USE PROGRAM REIMBURSE REVENUE	UT	148	-	-	-	-	148	-	-	-
4541000	RENTS - COMMON	301867	JOINT USE PROGRAM REIMBURSE REVENUE	WA	56	-	-	56	-	-	-	-	-
4541000	RENTS - COMMON	301867	JOINT USE PROGRAM REIMBURSE REVENUE	WYP	253	-	-	-	253	-	-	-	-
4541000	RENTS - COMMON	301869	UNCOLLECTIBLE REVENUE JOINT USE	CA	(0)	(0)	-	-	-	-	-	-	-
4541000	RENTS - COMMON	301869	UNCOLLECTIBLE REVENUE JOINT USE	IDU	0	-	-	-	-	-	0	-	-
4541000	RENTS - COMMON	301869	UNCOLLECTIBLE REVENUE JOINT USE	OR	11	-	11	-	-	-	-	-	-
4541000	RENTS - COMMON	301869	UNCOLLECTIBLE REVENUE JOINT USE	UT	64	-	-	-	-	64	-	-	-
4541000	RENTS - COMMON	301869	UNCOLLECTIBLE REVENUE JOINT USE	WA	9	-	-	9	-	-	-	-	-
4541000	RENTS - COMMON	301869	UNCOLLECTIBLE REVENUE JOINT USE	WYP	4	-	-	-	4	-	-	-	-
4541000	RENTS - COMMON	301870	RENT REV - STEAM	SG	17	0	5	1	2	8	1	0	-
4541000	RENTS - COMMON	301871	RENT REV - HYDRO	SG	11	0	3	1	1	5	1	0	-
4541000	RENTS - COMMON	301871	RENT REV - HYDRO	SO	19	0	5	1	2	8	1	0	-
4541000	RENTS - COMMON	301872	RENT REV - TRANS	SG	173	2	47	13	24	78	10	0	-
4541000	RENTS - COMMON	301873	RENT REV - DIST	SO	20	1	6	1	3	9	1	0	-
4541000	RENTS - COMMON	301874	RENT REV - GENERAL	SO	0	0	0	0	0	0	0	0	-
4541000	RENTS - COMMON	301878	JOINT USE BACK RENT	OR	3	-	3	-	-	-	-	-	-
4541000	RENTS - COMMON	301879	Joint Use Contracted Program Reimburseme	CA	17	17	-	-	-	-	-	-	-
4541000	RENTS - COMMON	301879	Joint Use Contracted Program Reimburseme	IDU	2	-	-	-	-	-	2	-	-
4541000	RENTS - COMMON	301879	Joint Use Contracted Program Reimburseme	OR	350	-	350	-	-	-	-	-	-
4541000	RENTS - COMMON	301879	Joint Use Contracted Program Reimburseme	UT	565	-	-	-	-	565	-	-	-
4541000	RENTS - COMMON	301879	Joint Use Contracted Program Reimburseme	WA	415	-	-	415	-	-	-	-	-
4541000	RENTS - COMMON	301879	Joint Use Contracted Program Reimburseme	WYP	161	-	-	-	161	-	-	-	-
4541000 Total					**17,216**	**625**	**6,527**	**1,606**	**1,346**	**6,695**	**417**	**0**	**0**
4543000	MCI FOGWIRE REVENUES	301863	MCI FIBER OPTIC GROUND WIRE REVENUES	SG	2,495	34	671	187	344	1,120	140	0	-
4543000 Total					**2,495**	**34**	**671**	**187**	**344**	**1,120**	**140**	**0**	**0**
4545000	VERT BRIDGE REVENUES	367222	Joint Use - Vertical Bridge Applic Fee	SG	3	0	1	0	0	1	0	0	-

PACIFICORP

Electric Operations Revenue (Actuals)
Sum of Range: 07/2022 - 06/2023
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Balance	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4545000 Total					**3**	**0**	**1**	**0**	**0**	**1**	**0**	**0**	**0**
4561100	Other Wheeling Rev	301953	Ancillary Rev Sch 6-Supp (C&T)	SG	2,707	37	728	203	373	1,215	151	0	-
4561100	Other Wheeling Rev	301963	Ancil Revenue Sch 2-Reactive (C&T)	SG	4,624	64	1,243	346	637	2,075	259	0	-
4561100	Other Wheeling Rev	301966	Primary Delivery and Distribution Sub Ch	SG	411	6	110	31	57	184	23	0	-
4561100	Other Wheeling Rev	301967	Ancillary Revenue Sch 1 - Scheduling	SG	3,038	42	817	227	418	1,363	170	0	-
4561100	Other Wheeling Rev	301969	Ancillary Revenue Sch 3 - Reg&Freq (C&T)	SG	1,977	27	532	148	272	887	111	0	-
4561100	Other Wheeling Rev	301973	Ancillary Revenue Sch 5&6-Spin&Supp (C&T	SG	2,683	37	721	201	370	1,204	150	0	-
4561100	Other Wheeling Rev	301974	Ancil Revenue Sch 3a-Regulation (C&T)	SG	4,723	65	1,270	354	651	2,120	264	0	-
4561100	Other Wheeling Rev	302082	I/C Anc Rev Sch 1-Scheduling-Nevada Pwr	SG	6	0	2	0	1	3	0	0	-
4561100	Other Wheeling Rev	302092	I/C Anc Rev Sch 2-Reactive-Nevada Pwr	SG	8	0	2	1	1	4	0	0	-
4561100	Other Wheeling Rev	302831	I/C Other Wheeling Revenue-Sierra Pac	SG	36	0	10	3	5	16	2	0	-
4561100	Other Wheeling Rev	302901	USE OF FACILITY REVENUE	SG	746	10	201	56	103	335	42	0	-
4561100	Other Wheeling Rev	302981	Transmission Resales to Other Parties	SG	1,050	14	282	79	145	471	59	0	-
4561100	Other Wheeling Rev	302982	Transmission Rev-Unreserved Use Charges	SG	8,502	117	2,286	637	1,171	3,816	476	0	-
4561100 Total					**30,511**	**420**	**8,203**	**2,285**	**4,203**	**13,694**	**1,707**	**0**	**0**
4561910	S/T FIRM WHEEL REV	301926	SHORT TERM FIRM WHEELING	SG	6,146	85	1,652	460	847	2,759	344	0	-
4561910 Total					**6,146**	**85**	**1,652**	**460**	**847**	**2,759**	**344**	**0**	**0**
4561920	L/T FIRM WHEEL REV	301912	POST-MERGER FIRM WHEELING	SG	18,776	259	5,048	1,406	2,587	8,427	1,050	0	-
4561920	L/T FIRM WHEEL REV	301916	PRE-MERGER FIRM WHEELING	SG	7,838	108	2,107	587	1,080	3,518	439	0	-
4561920	L/T FIRM WHEEL REV	301917	PRE-MERGER FIRM WHEELING	SG	30,572	421	8,219	2,289	4,212	13,721	1,710	0	-
4561920	L/T FIRM WHEEL REV	302961	TRANSM CAPACITY RE-ASSIGNMENT REVENUE	SG	619	9	166	46	85	278	35	0	-
4561920	L/T FIRM WHEEL REV	302962	TRANSM CAPACITY RE-ASSIGNMENT CONTRA REV	SG	(619)	(9)	(166)	(46)	(85)	(278)	(35)	(0)	-
4561920	L/T FIRM WHEEL REV	302980	Transmisson Point-to-Point Revenue	SG	59,463	819	15,986	4,453	8,192	26,687	3,327	0	-
4561920 Total					**116,650**	**1,606**	**31,360**	**8,735**	**16,070**	**52,353**	**6,526**	**0**	**0**
4561930	NON-FIRM WHEEL REV	301922	NON-FIRM WHEELING REVENUE	SE	32,562	414	8,577	2,221	4,838	14,554	1,959	0	-
4561930	NON-FIRM WHEEL REV	302822	I/C Non-Firm Wheeling Revenue-Nevada Pwr	SE	316	4	83	22	47	141	19	0	-
4561930 Total					**32,878**	**418**	**8,660**	**2,242**	**4,885**	**14,695**	**1,978**	**0**	**0**
4561990	TRANSMN REV REFUND	301913	Transmission Tariff True-up	SG	(4,445)	(61)	(1,195)	(333)	(612)	(1,995)	(249)	(0)	-
4561990 Total					**(4,445)**	**(61)**	**(1,195)**	**(333)**	**(612)**	**(1,995)**	**(249)**	**(0)**	**0**
4562100	USE OF FACIL REV	301911	"INCOME FROM FISH, WILDLIFE"	SG	12	0	3	1	2	5	1	0	-
4562100 Total					**12**	**0**	**3**	**1**	**2**	**5**	**1**	**0**	**0**
4562300	MISC OTHER REV	301900	ELECTRIC INCOME OTHER	UT	24	-	-	-	-	24	-	-	-
4562300	MISC OTHER REV	301900	ELECTRIC INCOME OTHER	WYU	0	-	-	-	0	-	-	-	-
4562300	MISC OTHER REV	301915	OTHER ELEC REV - MISC	SG	2,025	28	545	152	279	909	113	0	-
4562300	MISC OTHER REV	301939	Estimated Other Electric Revenue	SG	277	4	74	21	38	124	15	0	-
4562300	MISC OTHER REV	301940	FLYASH & BY-PRODUCT SALES	OTHER	(1,360)	-	-	-	-	-	-	-	(1,360)
4562300	MISC OTHER REV	301940	FLYASH & BY-PRODUCT SALES	SG	14,065	194	3,781	1,053	1,938	6,313	787	0	-
4562300	MISC OTHER REV	301949	THIRD PARTY TRN O&M REV	SG	136	2	37	10	19	61	8	0	-
4562300	MISC OTHER REV	301951	NON-WHEELING SYS REV	SG	1,391	19	374	104	192	624	78	0	-
4562300	MISC OTHER REV	301955	OTHER REV WY REG KENNECOTT	WYP	145	-	-	-	145	-	-	-	-
4562300	MISC OTHER REV	302071	I/C Transmission O&M Revenue-Sierra Pac	SG	7	0	2	1	1	3	0	0	-
4562300	MISC OTHER REV	361000	STEAM SALES	SG	1,180	16	317	88	163	530	66	0	-
4562300	MISC OTHER REV	374400	Timber Sales - Utility Property	SG	1,022	14	275	77	141	459	57	0	-
4562300 Total					**18,912**	**277**	**5,405**	**1,505**	**2,915**	**9,047**	**1,125**	**0**	**(1,360)**
4562310	EIM - MISCELLANEOUS	308001	EIM Rev-Forecasting Fee: Pac to TC	SG	16	0	4	1	2	7	1	0	-
4562310 Total					**16**	**0**	**4**	**1**	**2**	**7**	**1**	**0**	**0**
4562400	M&S INVENTORY SALES	362950	M&S INVENTORY SALES	SG	7	0	2	1	1	3	0	0	-
4562400	M&S INVENTORY SALES	362950	M&S INVENTORY SALES	SO	100	3	27	7	13	44	5	0	-
4562400	M&S INVENTORY SALES	362950	M&S INVENTORY SALES	UT	339	-	-	-	-	339	-	-	-
4562400	M&S INVENTORY SALES	362950	M&S INVENTORY SALES	WYP	24	-	-	-	24	-	-	-	-
4562400 Total					**471**	**3**	**29**	**8**	**38**	**387**	**6**	**0**	**0**
4562500	M&S INV COST OF SALE	514950	M&S INVENTORY COST OF SALES	UT	37	-	-	-	-	37	-	-	-
4562500 Total					**37**	**0**	**0**	**0**	**0**	**37**	**0**	**0**	**0**
4562700	RNW ENRGY CRDT SALES	301943	Renewable Energy Credit Sales-Deferral	SG	(3,203)	(44)	(861)	(240)	(441)	(1,438)	(179)	(0)	-
4562700	RNW ENRGY CRDT SALES	301944	Renewable Energy Credit Sales-Estimate	SG	(374)	(5)	(100)	(28)	(51)	(168)	(21)	(0)	-
4562700	RNW ENRGY CRDT SALES	301945	Renewable Energy Credit Sales	SG	10,238	141	2,752	767	1,410	4,595	573	0	-
4562700	RNW ENRGY CRDT SALES	352943	Renwbl En Cr Sls-Amt	OTHER	1,892	-	-	-	-	-	-	-	1,892
4562700	RNW ENRGY CRDT SALES	352950	REC Sales - Wind Wake Loss Indemnity	SG	21	0	6	2	3	10	1	0	-

PACIFICORP

Electric Operations Revenue (Actuals)
Sum of Range: 07/2022 - 06/2023
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Balance	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
4562700	RNW ENRGY CRDT SALES	354943	REC Sales - Pryor Mtn - Deferral	OTHER	606	-	-	-	-	-	-	-	606
4562700	RNW ENRGY CRDT SALES	354945	REC Sales - Blue Sky Program - Actual	OTHER	6,688	-	-	-	-	-	-	-	6,688
4562700 Total					**15,868**	**92**	**1,797**	**500**	**921**	**2,999**	**374**	**0**	**9,185**
4562800	CA GHG Emission Allo	352001	CA GHG Allowance Revenues	OTHER	15,218	-	-	-	-	-	-	-	15,218
4562800	CA GHG Emission Allo	352002	CA GHG Allowance Revenues - Deferral	OTHER	(15,218)	-	-	-	-	-	-	-	(15,218)
4562800	CA GHG Emission Allo	352003	CA GHG Allowance Revenues – Amortz	OTHER	11,871	-	-	-	-	-	-	-	11,871
4562800	CA GHG Emission Allo	352004	CA GHG Allow Revenues - SOMAH Amortz	OTHER	63	-	-	-	-	-	-	-	63
4562800 Total					**11,934**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**11,934**
4563500	Oth Elec Rev-Def Trn	305991	FERC Transmission Refund-Amortz	OR	4,075	-	4,075	-	-	-	-	-	-
4563500 Total					**4,075**	**0**	**4,075**	**0**	**0**	**0**	**0**	**0**	**0**
Grand Total					**5,863,692**	**116,293**	**1,543,857**	**447,320**	**689,598**	**2,545,280**	**343,216**	**14,357**	**163,771**

B2. O&M EXPENSE

PACIFICORP

Operations & Maintenance Expense (Actuals)
Sum of Range: 07/2022 - 06/2023
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Group Code	Secondary Group Code Name	Alloc	Balance	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
5000000	OPER SUPV & ENG	STEX	Steam O&M Expense	SG	13,977	192	3,758	1,047	1,926	6,273	782	0	-
5000000 Total					**13,977**	**192**	**3,758**	**1,047**	**1,926**	**6,273**	**782**	**0**	**-**
5001000	OPER SUPV & ENG	STEX	Steam O&M Expense	SG	655	9	176	49	90	294	37	0	-
5001000 Total					**655**	**9**	**176**	**49**	**90**	**294**	**37**	**0**	**-**
5010000	FUEL CONSUMED	NPCX	Net Power Cost Expense	SE	3,308	42	871	226	491	1,478	199	0	-
5010000 Total					**3,308**	**42**	**871**	**226**	**491**	**1,478**	**199**	**0**	**-**
5011000	FUEL CONSUMED-COAL	NPCX	Net Power Cost Expense	SE	535,837	6,810	141,135	36,545	79,615	239,502	32,230	0	-
5011000 Total					**535,837**	**6,810**	**141,135**	**36,545**	**79,615**	**239,502**	**32,230**	**0**	**-**
5011200	FUEL - OVRBDN AMORT	STEX	Steam O&M Expense	IDU	88	-	-	-	-	-	88	-	-
5011200	FUEL - OVRBDN AMORT	STEX	Steam O&M Expense	WYP	253	-	-	-	253	-	-	-	-
5011200 Total					**341**	**-**	**-**	**-**	**253**	**-**	**88**	**-**	**-**
5011300	FUEL-COAL DC UMWA PE	STEX	Steam O&M Expense	SE	2,845	36	749	194	423	1,271	171	0	-
5011300 Total					**2,845**	**36**	**749**	**194**	**423**	**1,271**	**171**	**0**	**-**
5011500	FUEL REG CST DFRL AM	STEX	Steam O&M Expense	SE	483	6	127	33	72	216	29	0	-
5011500 Total					**483**	**6**	**127**	**33**	**72**	**216**	**29**	**0**	**-**
5012000	FUEL HAND-COAL	STEX	Steam O&M Expense	SE	8,700	111	2,291	593	1,293	3,889	523	0	-
5012000 Total					**8,700**	**111**	**2,291**	**593**	**1,293**	**3,889**	**523**	**0**	**-**
5013000	START UP FUEL - GAS	NPCX	Net Power Cost Expense	SE	1,020	13	269	70	152	456	61	0	-
5013000 Total					**1,020**	**13**	**269**	**70**	**152**	**456**	**61**	**0**	**-**
5013500	FUEL CONSUMED-GAS	NPCX	Net Power Cost Expense	SE	62,876	799	16,561	4,288	9,342	28,103	3,782	0	-
5013500 Total					**62,876**	**799**	**16,561**	**4,288**	**9,342**	**28,103**	**3,782**	**0**	**-**
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	8,588	109	2,262	586	1,276	3,838	517	0	-
5014500 Total					**8,588**	**109**	**2,262**	**586**	**1,276**	**3,838**	**517**	**0**	**-**
5015000	FUEL CONS-RES DISP	NPCX	Net Power Cost Expense	SE	98	1	26	7	15	44	6	0	-
5015000 Total					**98**	**1**	**26**	**7**	**15**	**44**	**6**	**0**	**-**
5015100	ASH & ASH BYPRD SALE	NPCX	Net Power Cost Expense	SE	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	-
5015100 Total					**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**-**
5020000	STEAM EXPENSES	STEX	Steam O&M Expense	SG	43,415	598	11,672	3,251	5,981	19,485	2,429	0	-
5020000 Total					**43,415**	**598**	**11,672**	**3,251**	**5,981**	**19,485**	**2,429**	**0**	**-**
5022000	STM EXP - FLYASH	STEX	Steam O&M Expense	SG	4,045	56	1,087	303	557	1,815	226	0	-
5022000 Total					**4,045**	**56**	**1,087**	**303**	**557**	**1,815**	**226**	**0**	**-**
5023000	STM EXP BOTTOM ASH	STEX	Steam O&M Expense	SG	415	6	112	31	57	186	23	0	-
5023000 Total					**415**	**6**	**112**	**31**	**57**	**186**	**23**	**0**	**-**
5024000	STM EXP SCRUBBER	STEX	Steam O&M Expense	SG	11,270	155	3,030	844	1,553	5,058	630	0	-
5024000 Total					**11,270**	**155**	**3,030**	**844**	**1,553**	**5,058**	**630**	**0**	**-**
5029000	STM EXP - OTHER	STEX	Steam O&M Expense	SG	19,184	264	5,157	1,437	2,643	8,610	1,073	0	-
5029000 Total					**19,184**	**264**	**5,157**	**1,437**	**2,643**	**8,610**	**1,073**	**0**	**-**
5030000	STEAM FRM OTH SRCS	NPCX	Net Power Cost Expense	SE	11,211	142	2,953	765	1,666	5,011	674	0	-
5030000 Total					**11,211**	**142**	**2,953**	**765**	**1,666**	**5,011**	**674**	**0**	**-**
5050000	ELECTRIC EXPENSES	STEX	Steam O&M Expense	SG	691	10	186	52	95	310	39	0	-
5050000 Total					**691**	**10**	**186**	**52**	**95**	**310**	**39**	**0**	**-**
5051000	ELEC EXP GENERAL	STEX	Steam O&M Expense	SG	27	0	7	2	4	12	1	0	-
5051000 Total					**27**	**0**	**7**	**2**	**4**	**12**	**1**	**0**	**-**

PACIFICORP

Operations & Maintenance Expense (Actuals)
Sum of Range: 07/2022 - 06/2023
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Group Code	Secondary Group Code Name	Alloc	Balance	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
5060000	MISC STEAM PWR EXP	STEX	Steam O&M Expense	SG	52,224	719	14,040	3,911	7,194	23,438	2,922	0	-
5060000 Total					**52,224**	**719**	**14,040**	**3,911**	**7,194**	**23,438**	**2,922**	**0**	**-**
5061000	MISC STM EXP - CON	STEX	Steam O&M Expense	SG	943	13	254	71	130	423	53	0	-
5061000 Total					**943**	**13**	**254**	**71**	**130**	**423**	**53**	**0**	**-**
5061100	MISC STM EXP PLCLU	STEX	Steam O&M Expense	SG	1,528	21	411	114	210	686	85	0	-
5061100 Total					**1,528**	**21**	**411**	**114**	**210**	**686**	**85**	**0**	**-**
5061200	MISC STM EXP UNMTG	STEX	Steam O&M Expense	SG	19	0	5	1	3	9	1	0	-
5061200 Total					**19**	**0**	**5**	**1**	**3**	**9**	**1**	**0**	**-**
5061300	MISC STM EXP COMPT	STEX	Steam O&M Expense	SG	557	8	150	42	77	250	31	0	-
5061300 Total					**557**	**8**	**150**	**42**	**77**	**250**	**31**	**0**	**-**
5061400	MISC STM EXP OFFIC	STEX	Steam O&M Expense	SG	1,572	22	423	118	217	706	88	0	-
5061400 Total					**1,572**	**22**	**423**	**118**	**217**	**706**	**88**	**0**	**-**
5061500	MISC STM EXP COMM	STEX	Steam O&M Expense	SG	130	2	35	10	18	58	7	0	-
5061500 Total					**130**	**2**	**35**	**10**	**18**	**58**	**7**	**0**	**-**
5061600	MISC STM EXP FIRE	STEX	Steam O&M Expense	SG	1	0	0	0	0	1	0	0	-
5061600 Total					**1**	**0**	**0**	**0**	**0**	**1**	**0**	**0**	**-**
5062000	MISC STM - ENVRMNT	STEX	Steam O&M Expense	SG	3,775	52	1,015	283	520	1,694	211	0	-
5062000 Total					**3,775**	**52**	**1,015**	**283**	**520**	**1,694**	**211**	**0**	**-**
5063000	MISC STEAM JVA CR	STEX	Steam O&M Expense	SG	(41,436)	(571)	(11,140)	(3,103)	(5,708)	(18,596)	(2,318)	(0)	-
5063000 Total					**(41,436)**	**(571)**	**(11,140)**	**(3,103)**	**(5,708)**	**(18,596)**	**(2,318)**	**(0)**	**-**
5064000	MISC STM EXP RCRT	STEX	Steam O&M Expense	SG	26	0	7	2	4	11	1	0	-
5064000 Total					**26**	**0**	**7**	**2**	**4**	**11**	**1**	**0**	**-**
5065000	MISC STM EXP - SEC	STEX	Steam O&M Expense	SG	682	9	183	51	94	306	38	0	-
5065000 Total					**682**	**9**	**183**	**51**	**94**	**306**	**38**	**0**	**-**
5066000	MISC STM EXP -SFTY	STEX	Steam O&M Expense	SG	1,123	15	302	84	155	504	63	0	-
5066000 Total					**1,123**	**15**	**302**	**84**	**155**	**504**	**63**	**0**	**-**
5067000	MISC STM EXP TRNNG	STEX	Steam O&M Expense	SG	3,577	49	962	268	493	1,605	200	0	-
5067000 Total					**3,577**	**49**	**962**	**268**	**493**	**1,605**	**200**	**0**	**-**
5069000	MISC STM EXP WTSPY	STEX	Steam O&M Expense	SG	6,879	95	1,849	515	948	3,087	385	0	-
5069000 Total					**6,879**	**95**	**1,849**	**515**	**948**	**3,087**	**385**	**0**	**-**
5069900	MISC STM EXP MISC	STEX	Steam O&M Expense	SG	4,042	56	1,087	303	557	1,814	226	0	-
5069900 Total					**4,042**	**56**	**1,087**	**303**	**557**	**1,814**	**226**	**0**	**-**
5070000	RENTS (STEAM GEN)	STEX	Steam O&M Expense	SG	(215)	(3)	(58)	(16)	(30)	(97)	(12)	(0)	-
5070000 Total					**(215)**	**(3)**	**(58)**	**(16)**	**(30)**	**(97)**	**(12)**	**(0)**	**-**
5100000	MNT SUPERV & ENG	STEX	Steam O&M Expense	SG	1,453	20	391	109	200	652	81	0	-
5100000 Total					**1,453**	**20**	**391**	**109**	**200**	**652**	**81**	**0**	**-**
5101000	MNTNCE SUPVSN &ENG	STEX	Steam O&M Expense	SG	3,547	49	954	266	489	1,592	198	0	-
5101000 Total					**3,547**	**49**	**954**	**266**	**489**	**1,592**	**198**	**0**	**-**
5110000	MNT OF STRUCTURES	STEX	Steam O&M Expense	SG	1,999	28	537	150	275	897	112	0	-
5110000 Total					**1,999**	**28**	**537**	**150**	**275**	**897**	**112**	**0**	**-**
5111000	MNT OF STRUCTURES	STEX	Steam O&M Expense	SG	5,960	82	1,602	446	821	2,675	333	0	-
5111000 Total					**5,960**	**82**	**1,602**	**446**	**821**	**2,675**	**333**	**0**	**-**
5111100	MNT STRCT PMP PLNT	STEX	Steam O&M Expense	SG	877	12	236	66	121	394	49	0	-
5111100 Total					**877**	**12**	**236**	**66**	**121**	**394**	**49**	**0**	**-**
5111200	MNT STRCT WASTE WT	STEX	Steam O&M Expense	SG	926	13	249	69	128	415	52	0	-

PACIFICORP

Operations & Maintenance Expense (Actuals)
Sum of Range: 07/2022 - 06/2023
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Group Code	Secondary Group Code Name	Alloc	Balance	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
5111200 Total					**926**	**13**	**249**	**69**	**128**	**415**	**52**	**0**	**-**
5112000	STRUCTURAL SYSTEMS	STEX	Steam O&M Expense	SG	8,035	111	2,160	602	1,107	3,606	449	0	-
5112000 Total					**8,035**	**111**	**2,160**	**602**	**1,107**	**3,606**	**449**	**0**	**-**
5114000	MNT OF STRCT CATH	STEX	Steam O&M Expense	SG	20	0	5	1	3	9	1	0	-
5114000 Total					**20**	**0**	**5**	**1**	**3**	**9**	**1**	**0**	**-**
5116000	MNT STRCT DAM RIVR	STEX	Steam O&M Expense	SG	129	2	35	10	18	58	7	0	-
5116000 Total					**129**	**2**	**35**	**10**	**18**	**58**	**7**	**0**	**-**
5117000	MNT STRCT FIRE PRT	STEX	Steam O&M Expense	SG	1,480	20	398	111	204	664	83	0	-
5117000 Total					**1,480**	**20**	**398**	**111**	**204**	**664**	**83**	**0**	**-**
5118000	MNT STRCT-GROUNDS	STEX	Steam O&M Expense	SG	753	10	202	56	104	338	42	0	-
5118000 Total					**753**	**10**	**202**	**56**	**104**	**338**	**42**	**0**	**-**
5119000	MNT OF STRCT-HVAC	STEX	Steam O&M Expense	SG	1,538	21	413	115	212	690	86	0	-
5119000 Total					**1,538**	**21**	**413**	**115**	**212**	**690**	**86**	**0**	**-**
5119900	MNT OF STRCT-MISC	STEX	Steam O&M Expense	SG	937	13	252	70	129	421	52	0	-
5119900 Total					**937**	**13**	**252**	**70**	**129**	**421**	**52**	**0**	**-**
5120000	MANT OF BOILR PLNT	STEX	Steam O&M Expense	SG	9,849	136	2,648	738	1,357	4,420	551	0	-
5120000 Total					**9,849**	**136**	**2,648**	**738**	**1,357**	**4,420**	**551**	**0**	**-**
5121000	MNT BOILR-AIR HTR	STEX	Steam O&M Expense	SG	6,452	89	1,734	483	889	2,895	361	0	-
5121000 Total					**6,452**	**89**	**1,734**	**483**	**889**	**2,895**	**361**	**0**	**-**
5121100	MNT BOILR-CHEM FD	STEX	Steam O&M Expense	SG	147	2	39	11	20	66	8	0	-
5121100 Total					**147**	**2**	**39**	**11**	**20**	**66**	**8**	**0**	**-**
5121200	MNT BOILR-CL HANDL	STEX	Steam O&M Expense	SG	3,992	55	1,073	299	550	1,792	223	0	-
5121200 Total					**3,992**	**55**	**1,073**	**299**	**550**	**1,792**	**223**	**0**	**-**
5121400	MNT BOIL-DEMINERLZ	STEX	Steam O&M Expense	SG	350	5	94	26	48	157	20	0	-
5121400 Total					**350**	**5**	**94**	**26**	**48**	**157**	**20**	**0**	**-**
5121500	MNT BOIL-EXTRC STM	STEX	Steam O&M Expense	SG	372	5	100	28	51	167	21	0	-
5121500 Total					**372**	**5**	**100**	**28**	**51**	**167**	**21**	**0**	**-**
5121600	MNT BOILR-FLYASH	STEX	Steam O&M Expense	SG	3,668	51	986	275	505	1,646	205	0	-
5121600 Total					**3,668**	**51**	**986**	**275**	**505**	**1,646**	**205**	**0**	**-**
5121700	MNT BOIL-FUEL OIL	STEX	Steam O&M Expense	SG	781	11	210	58	108	350	44	0	-
5121700 Total					**781**	**11**	**210**	**58**	**108**	**350**	**44**	**0**	**-**
5121800	MNT BOIL-FEEDWATR	STEX	Steam O&M Expense	SG	5,200	72	1,398	389	716	2,334	291	0	-
5121800 Total					**5,200**	**72**	**1,398**	**389**	**716**	**2,334**	**291**	**0**	**-**
5121900	MNT BOIL-FRZ PRTEC	STEX	Steam O&M Expense	SG	44	1	12	3	6	20	2	0	-
5121900 Total					**44**	**1**	**12**	**3**	**6**	**20**	**2**	**0**	**-**
5122000	MNT BOILR-AUX SYST	STEX	Steam O&M Expense	SG	836	12	225	63	115	375	47	0	-
5122000 Total					**836**	**12**	**225**	**63**	**115**	**375**	**47**	**0**	**-**
5122100	MNT BOILR-MAIN STM	STEX	Steam O&M Expense	SG	3,671	51	987	275	506	1,647	205	0	-
5122100 Total					**3,671**	**51**	**987**	**275**	**506**	**1,647**	**205**	**0**	**-**
5122200	MNT BOIL-PLVRZD CL	STEX	Steam O&M Expense	SG	8,400	116	2,258	629	1,157	3,770	470	0	-
5122200 Total					**8,400**	**116**	**2,258**	**629**	**1,157**	**3,770**	**470**	**0**	**-**
5122300	MNT BOIL-PRECIP/BAG	STEX	Steam O&M Expense	SG	3,150	43	847	236	434	1,414	176	0	-
5122300 Total					**3,150**	**43**	**847**	**236**	**434**	**1,414**	**176**	**0**	**-**
5122400	MNT BOIL-PRTRT WTR	STEX	Steam O&M Expense	SG	414	6	111	31	57	186	23	0	-
5122400 Total					**414**	**6**	**111**	**31**	**57**	**186**	**23**	**0**	**-**

PACIFICORP

Operations & Maintenance Expense (Actuals)
Sum of Range: 07/2022 - 06/2023
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Group Code	Secondary Group Code Name	Alloc	Balance	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
5122500	MNT BOIL-RV OSMSIS	STEX	Steam O&M Expense	SG	140	2	38	11	19	63	8	0	-
5122500 Total					**140**	**2**	**38**	**11**	**19**	**63**	**8**	**0**	**-**
5122600	MNT BOIL-RHEAT ST	STEX	Steam O&M Expense	SG	419	6	113	31	58	188	23	0	-
5122600 Total					**419**	**6**	**113**	**31**	**58**	**188**	**23**	**0**	**-**
5122800	MNT BOIL-SOOTBLWG	STEX	Steam O&M Expense	SG	1,980	27	532	148	273	889	111	0	-
5122800 Total					**1,980**	**27**	**532**	**148**	**273**	**889**	**111**	**0**	**-**
5122900	MNT BOILR-SCRUBBER	STEX	Steam O&M Expense	SG	5,983	82	1,608	448	824	2,685	335	0	-
5122900 Total					**5,983**	**82**	**1,608**	**448**	**824**	**2,685**	**335**	**0**	**-**
5123000	MNT BOILR-BOTM ASH	STEX	Steam O&M Expense	SG	2,750	38	739	206	379	1,234	154	0	-
5123000 Total					**2,750**	**38**	**739**	**206**	**379**	**1,234**	**154**	**0**	**-**
5123100	MNT BOIL-WTR TRTMT	STEX	Steam O&M Expense	SG	311	4	84	23	43	139	17	0	-
5123100 Total					**311**	**4**	**84**	**23**	**43**	**139**	**17**	**0**	**-**
5123200	MNT BOIL-CNTL SUPT	STEX	Steam O&M Expense	SG	318	4	86	24	44	143	18	0	-
5123200 Total					**318**	**4**	**86**	**24**	**44**	**143**	**18**	**0**	**-**
5123300	MAINT GEO GATH SYS	STEX	Steam O&M Expense	SG	140	2	38	10	19	63	8	0	-
5123300 Total					**140**	**2**	**38**	**10**	**19**	**63**	**8**	**0**	**-**
5123400	MAINT OF BOILERS	STEX	Steam O&M Expense	SG	3,031	42	815	227	418	1,360	170	0	-
5123400 Total					**3,031**	**42**	**815**	**227**	**418**	**1,360**	**170**	**0**	**-**
5124000	MNT BOILR-CONTROLS	STEX	Steam O&M Expense	SG	1,045	14	281	78	144	469	58	0	-
5124000 Total					**1,045**	**14**	**281**	**78**	**144**	**469**	**58**	**0**	**-**
5125000	MNT BOILER-DRAFT	STEX	Steam O&M Expense	SG	3,317	46	892	248	457	1,489	186	0	-
5125000 Total					**3,317**	**46**	**892**	**248**	**457**	**1,489**	**186**	**0**	**-**
5126000	MNT BOILR-FIRESIDE	STEX	Steam O&M Expense	SG	2,106	29	566	158	290	945	118	0	-
5126000 Total					**2,106**	**29**	**566**	**158**	**290**	**945**	**118**	**0**	**-**
5127000	MNT BLR-BEARNG WTR	STEX	Steam O&M Expense	SG	304	4	82	23	42	137	17	0	-
5127000 Total					**304**	**4**	**82**	**23**	**42**	**137**	**17**	**0**	**-**
5128000	MNT BOILR WTR/STMD	STEX	Steam O&M Expense	SG	9,772	135	2,627	732	1,346	4,386	547	0	-
5128000 Total					**9,772**	**135**	**2,627**	**732**	**1,346**	**4,386**	**547**	**0**	**-**
5129000	MNT BOIL-COMP AIR	STEX	Steam O&M Expense	SG	1,947	27	523	146	268	874	109	0	-
5129000 Total					**1,947**	**27**	**523**	**146**	**268**	**874**	**109**	**0**	**-**
5129900	MAINT BOILER-MISC	STEX	Steam O&M Expense	SG	5,415	75	1,456	406	746	2,430	303	0	-
5129900 Total					**5,415**	**75**	**1,456**	**406**	**746**	**2,430**	**303**	**0**	**-**
5130000	MAINT ELEC PLANT	STEX	Steam O&M Expense	SG	3,464	48	931	259	477	1,555	194	0	-
5130000 Total					**3,464**	**48**	**931**	**259**	**477**	**1,555**	**194**	**0**	**-**
5131000	MAINT ELEC AC	STEX	Steam O&M Expense	SG	17,661	243	4,748	1,323	2,433	7,927	988	0	-
5131000 Total					**17,661**	**243**	**4,748**	**1,323**	**2,433**	**7,927**	**988**	**0**	**-**
5131100	MAINT/LUBE-OIL SYS	STEX	Steam O&M Expense	SG	998	14	268	75	137	448	56	0	-
5131100 Total					**998**	**14**	**268**	**75**	**137**	**448**	**56**	**0**	**-**
5131300	MAINT/PREVENT ROUT	STEX	Steam O&M Expense	SG	8	0	2	1	1	4	0	0	-
5131300 Total					**8**	**0**	**2**	**1**	**1**	**4**	**0**	**0**	**-**
5131400	MAINT/MAIN TURBINE	STEX	Steam O&M Expense	SG	6,477	89	1,741	485	892	2,907	362	0	-
5131400 Total					**6,477**	**89**	**1,741**	**485**	**892**	**2,907**	**362**	**0**	**-**
5132000	MAINT ALARMS/INFO	STEX	Steam O&M Expense	SG	2,329	32	626	174	321	1,045	130	0	-
5132000 Total					**2,329**	**32**	**626**	**174**	**321**	**1,045**	**130**	**0**	**-**
5133000	MAINT/AIR-COOL-CON	STEX	Steam O&M Expense	SG	113	2	30	8	16	51	6	0	-

PACIFICORP

Operations & Maintenance Expense (Actuals)
Sum of Range: 07/2022 - 06/2023
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Group Code	Secondary Group Code Name	Alloc	Balance	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
5133000 Total					**113**	**2**	**30**	**8**	**16**	**51**	**6**	**0**	**-**
5134000	MAINT/COMPNT COOL	STEX	Steam O&M Expense	SG	212	3	57	16	29	95	12	0	-
5134000 Total					**212**	**3**	**57**	**16**	**29**	**95**	**12**	**0**	**-**
5135000	MAINT/COMPNT AUXIL	STEX	Steam O&M Expense	SG	1,302	18	350	97	179	584	73	0	-
5135000 Total					**1,302**	**18**	**350**	**97**	**179**	**584**	**73**	**0**	**-**
5137000	MAINT-COOLING TOWR	STEX	Steam O&M Expense	SG	1,468	20	395	110	202	659	82	0	-
5137000 Total					**1,468**	**20**	**395**	**110**	**202**	**659**	**82**	**0**	**-**
5138000	MAINT-CIRCUL WATER	STEX	Steam O&M Expense	SG	2,296	32	617	172	316	1,031	128	0	-
5138000 Total					**2,296**	**32**	**617**	**172**	**316**	**1,031**	**128**	**0**	**-**
5139000	MAINT-ELECT - DC	STEX	Steam O&M Expense	SG	324	4	87	24	45	145	18	0	-
5139000 Total					**324**	**4**	**87**	**24**	**45**	**145**	**18**	**0**	**-**
5139900	MNT ELEC PLT-MISC	STEX	Steam O&M Expense	SG	81	1	22	6	11	36	5	0	-
5139900 Total					**81**	**1**	**22**	**6**	**11**	**36**	**5**	**0**	**-**
5140000	MAINT MISC STM PLN	STEX	Steam O&M Expense	SG	2,611	36	702	196	360	1,172	146	0	-
5140000 Total					**2,611**	**36**	**702**	**196**	**360**	**1,172**	**146**	**0**	**-**
5141000	MISC STM-COMP AIR	STEX	Steam O&M Expense	SG	1,000	14	269	75	138	449	56	0	-
5141000 Total					**1,000**	**14**	**269**	**75**	**138**	**449**	**56**	**0**	**-**
5142000	MISC STM PLT-CONSU	STEX	Steam O&M Expense	SG	591	8	159	44	81	265	33	0	-
5142000 Total					**591**	**8**	**159**	**44**	**81**	**265**	**33**	**0**	**-**
5144000	MISC STM PLNT-LAB	STEX	Steam O&M Expense	SG	375	5	101	28	52	168	21	0	-
5144000 Total					**375**	**5**	**101**	**28**	**52**	**168**	**21**	**0**	**-**
5145000	MAINT MISC-SM TOOL	STEX	Steam O&M Expense	SG	1,311	18	352	98	181	588	73	0	-
5145000 Total					**1,311**	**18**	**352**	**98**	**181**	**588**	**73**	**0**	**-**
5146000	MAINT/PAGING SYS	STEX	Steam O&M Expense	SG	237	3	64	18	33	106	13	0	-
5146000 Total					**237**	**3**	**64**	**18**	**33**	**106**	**13**	**0**	**-**
5147000	MAINT/PLANT EQUIP	STEX	Steam O&M Expense	SG	1,370	19	368	103	189	615	77	0	-
5147000 Total					**1,370**	**19**	**368**	**103**	**189**	**615**	**77**	**0**	**-**
5148000	MAINT/PLT-VEHICLES	STEX	Steam O&M Expense	SG	2,720	37	731	204	375	1,221	152	0	-
5148000 Total					**2,720**	**37**	**731**	**204**	**375**	**1,221**	**152**	**0**	**-**
5149000	MAINT MISC-OTHER	STEX	Steam O&M Expense	SG	901	12	242	67	124	404	50	0	-
5149000 Total					**901**	**12**	**242**	**67**	**124**	**404**	**50**	**0**	**-**
5149500	MAINT STM PLT-ENV AM	STEX	Steam O&M Expense	SG	3,276	45	881	245	451	1,470	183	0	-
5149500 Total					**3,276**	**45**	**881**	**245**	**451**	**1,470**	**183**	**0**	**-**
5350000	OPER SUPERV & ENG	HYEX	Hydro O&M Expense	SG-P	9,055	125	2,434	678	1,247	4,064	507	0	-
5350000	OPER SUPERV & ENG	HYEX	Hydro O&M Expense	SG-U	3,423	47	920	256	472	1,536	191	0	-
5350000 Total					**12,478**	**172**	**3,355**	**934**	**1,719**	**5,600**	**698**	**0**	**-**
5360000	WATER FOR POWER	HYEX	Hydro O&M Expense	SG-P	465	6	125	35	64	209	26	0	-
5360000 Total					**465**	**6**	**125**	**35**	**64**	**209**	**26**	**0**	**-**
5370000	HYDRAULIC EXPENSES	HYEX	Hydro O&M Expense	SG-P	2,630	36	707	197	362	1,180	147	0	-
5370000 Total					**2,630**	**36**	**707**	**197**	**362**	**1,180**	**147**	**0**	**-**
5371000	HYDRO/FISH & WILD	HYEX	Hydro O&M Expense	SG-P	630	9	169	47	87	283	35	0	-
5371000	HYDRO/FISH & WILD	HYEX	Hydro O&M Expense	SG-U	156	2	42	12	22	70	9	0	-
5371000 Total					**787**	**11**	**212**	**59**	**108**	**353**	**44**	**0**	**-**
5372000	HYDRO/HATCHERY EXP	HYEX	Hydro O&M Expense	SG-P	98	1	26	7	13	44	5	0	-
5372000 Total					**98**	**1**	**26**	**7**	**13**	**44**	**5**	**0**	**-**

PACIFICORP

Operations & Maintenance Expense (Actuals)
Sum of Range: 07/2022 - 06/2023
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Group Code	Secondary Group Code Name	Alloc	Balance	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
5374000	HYDRO/OTH REC FAC	HYEX	Hydro O&M Expense	SG-P	218	3	59	16	30	98	12	0	-
5374000	HYDRO/OTH REC FAC	HYEX	Hydro O&M Expense	SG-U	27	0	7	2	4	12	2	0	-
5374000 Total					**245**	**3**	**66**	**18**	**34**	**110**	**14**	**0**	**-**
5379000	HYDRO EXPENSE-OTH	HYEX	Hydro O&M Expense	SG-P	539	7	145	40	74	242	30	0	-
5379000	HYDRO EXPENSE-OTH	HYEX	Hydro O&M Expense	SG-U	158	2	42	12	22	71	9	0	-
5379000 Total					**697**	**10**	**187**	**52**	**96**	**313**	**39**	**0**	**-**
5390000	MSC HYD PWR GEN EX	HYEX	Hydro O&M Expense	SG-P	14,847	204	3,991	1,112	2,045	6,663	831	0	-
5390000	MSC HYD PWR GEN EX	HYEX	Hydro O&M Expense	SG-U	7,957	110	2,139	596	1,096	3,571	445	0	-
5390000 Total					**22,804**	**314**	**6,131**	**1,708**	**3,142**	**10,234**	**1,276**	**0**	**-**
5400000	RENTS (HYDRO GEN)	HYEX	Hydro O&M Expense	SG-P	1,757	24	472	132	242	789	98	0	-
5400000	RENTS (HYDRO GEN)	HYEX	Hydro O&M Expense	SG-U	(133)	(2)	(36)	(10)	(18)	(60)	(7)	(0)	-
5400000 Total					**1,624**	**22**	**437**	**122**	**224**	**729**	**91**	**0**	**-**
5410000	MNT SUPERV & ENG	HYEX	Hydro O&M Expense	SG-P	2	0	0	0	0	1	0	0	-
5410000 Total					**2**	**0**	**0**	**0**	**0**	**1**	**0**	**0**	**-**
5420000	MAINT OF STRUCTURE	HYEX	Hydro O&M Expense	SG-P	733	10	197	55	101	329	41	0	-
5420000	MAINT OF STRUCTURE	HYEX	Hydro O&M Expense	SG-U	22	0	6	2	3	10	1	0	-
5420000 Total					**755**	**10**	**203**	**57**	**104**	**339**	**42**	**0**	**-**
5430000	MNT DAMS & WTR SYS	HYEX	Hydro O&M Expense	SG-P	931	13	250	70	128	418	52	0	-
5430000	MNT DAMS & WTR SYS	HYEX	Hydro O&M Expense	SG-U	505	7	136	38	70	227	28	0	-
5430000 Total					**1,436**	**20**	**386**	**108**	**198**	**645**	**80**	**0**	**-**
5440000	MAINT OF ELEC PLNT	HYEX	Hydro O&M Expense	SG-U	132	2	36	10	18	59	7	0	-
5440000 Total					**132**	**2**	**36**	**10**	**18**	**59**	**7**	**0**	**-**
5441000	PRIME MOVERS & GEN	HYEX	Hydro O&M Expense	SG-P	627	9	169	47	86	281	35	0	-
5441000	PRIME MOVERS & GEN	HYEX	Hydro O&M Expense	SG-U	149	2	40	11	21	67	8	0	-
5441000 Total					**776**	**11**	**209**	**58**	**107**	**348**	**43**	**0**	**-**
5442000	ACCESS ELEC EQUIP	HYEX	Hydro O&M Expense	SG-P	827	11	222	62	114	371	46	0	-
5442000	ACCESS ELEC EQUIP	HYEX	Hydro O&M Expense	SG-U	61	1	17	5	8	28	3	0	-
5442000 Total					**888**	**12**	**239**	**67**	**122**	**399**	**50**	**0**	**-**
5450000	MNT MISC HYDRO PLT	HYEX	Hydro O&M Expense	SG-P	15	0	4	1	2	7	1	0	-
5450000 Total					**15**	**0**	**4**	**1**	**2**	**7**	**1**	**0**	**-**
5451000	MNT-FISH/WILDLIFE	HYEX	Hydro O&M Expense	SG-P	977	13	263	73	135	438	55	0	-
5451000 Total					**977**	**13**	**263**	**73**	**135**	**438**	**55**	**0**	**-**
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	498	7	134	37	69	224	28	0	-
5455000	MAINT-RDS/TRAIL/BR	HYEX	Hydro O&M Expense	SG-U	436	6	117	33	60	196	24	0	-
5455000 Total					**934**	**13**	**251**	**70**	**129**	**419**	**52**	**0**	**-**
5459000	MAINT HYDRO-OTHER	HYEX	Hydro O&M Expense	SG	(7,385)	(102)	(1,985)	(553)	(1,017)	(3,314)	(413)	(0)	-
5459000	MAINT HYDRO-OTHER	HYEX	Hydro O&M Expense	SG-P	1,548	21	416	116	213	695	87	0	-
5459000	MAINT HYDRO-OTHER	HYEX	Hydro O&M Expense	SG-U	484	7	130	36	67	217	27	0	-
5459000 Total					**(5,353)**	**(74)**	**(1,439)**	**(401)**	**(737)**	**(2,403)**	**(299)**	**(0)**	**-**
5459500	MAINT OF HYDRO PLT-E	HYEX	Hydro O&M Expense	SG-P	269	4	72	20	37	121	15	0	-
5459500 Total					**269**	**4**	**72**	**20**	**37**	**121**	**15**	**0**	**-**
5460000	OPER SUPERV & ENG	OPEX	Other Production O&M Expense	SG	505	7	136	38	70	227	28	0	-
5460000 Total					**505**	**7**	**136**	**38**	**70**	**227**	**28**	**0**	**-**

PACIFICORP

Operations & Maintenance Expense (Actuals)
Sum of Range: 07/2022 - 06/2023
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Group Code	Secondary Group Code Name	Alloc	Balance	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
5471000	NATURAL GAS	NPCX	Net Power Cost Expense	SE	621,728	7,902	163,758	42,403	92,377	277,892	37,396	0	-
5471000 Total					**621,728**	**7,902**	**163,758**	**42,403**	**92,377**	**277,892**	**37,396**	**0**	**-**
5480000	GENERATION EXP	OPEX	Other Production O&M Expense	SG	23,622	325	6,351	1,769	3,254	10,602	1,321	0	-
5480000 Total					**23,622**	**325**	**6,351**	**1,769**	**3,254**	**10,602**	**1,321**	**0**	**-**
5490000	MIS OTH PWR GEN EX	OPEX	Other Production O&M Expense	OR	33	-	33	-	-	-	-	-	-
5490000	MIS OTH PWR GEN EX	OPEX	Other Production O&M Expense	SG	10,702	147	2,877	801	1,474	4,803	599	0	-
5490000 Total					**10,735**	**147**	**2,910**	**801**	**1,474**	**4,803**	**599**	**0**	**-**
5500000	RENTS (OTHER GEN)	OPEX	Other Production O&M Expense	OR	374	-	374	-	-	-	-	-	-
5500000	RENTS (OTHER GEN)	OPEX	Other Production O&M Expense	SG	10,680	147	2,871	800	1,471	4,793	597	0	-
5500000 Total					**11,054**	**147**	**3,246**	**800**	**1,471**	**4,793**	**597**	**0**	**-**
5520000	MAINT OF STRUCTURE	OPEX	Other Production O&M Expense	SG	2,509	35	675	188	346	1,126	140	0	-
5520000 Total					**2,509**	**35**	**675**	**188**	**346**	**1,126**	**140**	**0**	**-**
5530000	MNT GEN & ELEC PLT	OPEX	Other Production O&M Expense	SG	21,828	301	5,868	1,634	3,007	9,796	1,221	0	-
5530000 Total					**21,828**	**301**	**5,868**	**1,634**	**3,007**	**9,796**	**1,221**	**0**	**-**
5540000	MNT MSC OTH PWR GN	OPEX	Other Production O&M Expense	SG	2,018	28	543	151	278	906	113	0	-
5540000 Total					**2,018**	**28**	**543**	**151**	**278**	**906**	**113**	**0**	**-**
5546000	MISC PLANT EQUIP	OPEX	Other Production O&M Expense	SG	19	0	5	1	3	9	1	0	-
5546000 Total					**19**	**0**	**5**	**1**	**3**	**9**	**1**	**0**	**-**
5549500	MAINT OF OTH PWR PLT	OPEX	Other Production O&M Expense	SG	2,065	28	555	155	284	927	116	0	-
5549500 Total					**2,065**	**28**	**555**	**155**	**284**	**927**	**116**	**0**	**-**
5550000	PURCHASED POWER	PSEX	Power Supply Expense	SG	407	6	109	30	56	183	23	0	-
5550000 Total					**407**	**6**	**109**	**30**	**56**	**183**	**23**	**0**	**-**
5552400	RENEW ENRGY CR PURCH	NPCX	Net Power Cost Expense	OTHER	7,414	-	-	-	-	-	-	-	7,414
5552400 Total					**7,414**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**7,414**
5552500	OTH/INT/REC/DEL	NPCX	Net Power Cost Expense	SE	20,074	255	5,287	1,369	2,983	8,972	1,207	0	-
5552500 Total					**20,074**	**255**	**5,287**	**1,369**	**2,983**	**8,972**	**1,207**	**0**	**-**
5552700	PURCH POWER-UT SITUS	NPCX	Net Power Cost Expense	UT	13,361	-	-	-	-	13,361	-	-	-
5552700 Total					**13,361**	**-**	**-**	**-**	**-**	**13,361**	**-**	**-**	**-**
5552800	PURCH POWER-OR SITUS	NPCX	Net Power Cost Expense	OR	80	-	80	-	-	-	-	-	-
5552800 Total					**80**	**-**	**80**	**-**	**-**	**-**	**-**	**-**	**-**
5552900	PURCH POWER-CA SITUS	NPCX	Net Power Cost Expense	CA	3	3	-	-	-	-	-	-	-
5552900 Total					**3**	**3**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
5555700	NPC Deferral Mchnsm	NPCX	Net Power Cost Expense	OTHER	(527,210)	-	-	-	-	-	-	-	(527,210)
5555700 Total					**(527,210)**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**(527,210)**
5555900	Short-Term Firm Whls	NPCX	Net Power Cost Expense	SG	915,677	12,608	246,172	68,568	126,145	410,959	51,225	0	-
5555900 Total					**915,677**	**12,608**	**246,172**	**68,568**	**126,145**	**410,959**	**51,225**	**0**	**-**
5556200	TRADING NETTED-LOSS	NPCX	Net Power Cost Expense	SG	0	0	0	0	0	0	0	0	-
5556200 Total					**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**-**
5556300	FIRM ENERGY PURCH	NPCX	Net Power Cost Expense	SG	454,954	6,264	122,311	34,068	62,675	204,185	25,451	0	-
5556300 Total					**454,954**	**6,264**	**122,311**	**34,068**	**62,675**	**204,185**	**25,451**	**0**	**-**
5556400	FIRM DEMAND PURCH	NPCX	Net Power Cost Expense	SG	36,952	509	9,934	2,767	5,091	16,584	2,067	0	-
5556400 Total					**36,952**	**509**	**9,934**	**2,767**	**5,091**	**16,584**	**2,067**	**0**	**-**
5556700	POST-MERG FIRM PUR	NPCX	Net Power Cost Expense	SG	(12,467)	(172)	(3,352)	(934)	(1,717)	(5,595)	(697)	(0)	-
5556700	POST-MERG FIRM PUR	NPCX	Net Power Cost Expense	SG	5,835	80	1,569	437	804	2,619	326	0	-
5556700 Total					**(6,632)**	**(91)**	**(1,783)**	**(497)**	**(914)**	**(2,976)**	**(371)**	**(0)**	**-**

PACIFICORP

Operations & Maintenance Expense (Actuals)
Sum of Range: 07/2022 - 06/2023
Allocation Method - Factor 2020 Protocol
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Primary Account	Primary Account Name	Secondary Group Code	Secondary Group Code Name	Alloc	Balance	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
5556710	EIM - FIRM PURCHASES	NPCX	Net Power Cost Expense	SG	(193,578)	(2,665)	(52,042)	(14,496)	(26,668)	(86,878)	(10,829)	(0)	-
5556710 Total					**(193,578)**	**(2,665)**	**(52,042)**	**(14,496)**	**(26,668)**	**(86,878)**	**(10,829)**	**(0)**	**-**
5560000	SYS CTRL & LD DISP	PSEX	Power Supply Expense	SG	2,506	35	674	188	345	1,125	140	0	-
5560000 Total					**2,506**	**35**	**674**	**188**	**345**	**1,125**	**140**	**0**	**-**
5570000	OTHER EXPENSES	PSEX	Power Supply Expense	SE	6	0	2	0	1	3	0	0	-
5570000	OTHER EXPENSES	PSEX	Power Supply Expense	SG	33,441	460	8,990	2,504	4,607	15,008	1,871	0	-
5570000 Total					**33,447**	**461**	**8,992**	**2,505**	**4,608**	**15,011**	**1,871**	**0**	**-**
5579000	OTH EXP-ST SITUS ACT	PSEX	Power Supply Expense	IDU	3,589	-	-	-	-	-	3,589	-	-
5579000	OTH EXP-ST SITUS ACT	PSEX	Power Supply Expense	OR	7,786	-	7,786	-	-	-	-	-	-
5579000 Total					**11,376**	**-**	**7,786**	**-**	**-**	**-**	**3,589**	**-**	**-**
5579100	OTH EXP-LIQ DAMAGE	PSEX	Power Supply Expense	UT	35	-	-	-	-	35	-	-	-
5579100	OTH EXP-LIQ DAMAGE	PSEX	Power Supply Expense	WYU	62	-	-	-	62	-	-	-	-
5579100 Total					**97**	**-**	**-**	**-**	**62**	**35**	**-**	**-**	**-**
5600000	OPER SUPERV & ENG	TNEX	Transmission O&M Expense	SG	10,930	150	2,938	818	1,506	4,905	611	0	-
5600000 Total					**10,930**	**150**	**2,938**	**818**	**1,506**	**4,905**	**611**	**0**	**-**
5612000	LD - MONITOR & OPER	TNEX	Transmission O&M Expense	SG	7,568	104	2,035	567	1,043	3,396	423	0	-
5612000 Total					**7,568**	**104**	**2,035**	**567**	**1,043**	**3,396**	**423**	**0**	**-**
5614000	SCHED, SYS CTR & DSP	TNEX	Transmission O&M Expense	SG	257	4	69	19	35	115	14	0	-
5614000 Total					**257**	**4**	**69**	**19**	**35**	**115**	**14**	**0**	**-**
5614010	EIM - SCHEDULING,SYS	TNEX	Transmission O&M Expense	SG	652	9	175	49	90	293	36	0	-
5614010 Total					**652**	**9**	**175**	**49**	**90**	**293**	**36**	**0**	**-**
5615000	REL PLAN & STDS DEV	TNEX	Transmission O&M Expense	SG	2,874	40	773	215	396	1,290	161	0	-
5615000 Total					**2,874**	**40**	**773**	**215**	**396**	**1,290**	**161**	**0**	**-**
5616000	TRANS SVC STUDIES	TNEX	Transmission O&M Expense	SG	128	2	34	10	18	58	7	0	-
5616000 Total					**128**	**2**	**34**	**10**	**18**	**58**	**7**	**0**	**-**
5617000	GEN INTERCNCT STUD	TNEX	Transmission O&M Expense	SG	1,789	25	481	134	246	803	100	0	-
5617000 Total					**1,789**	**25**	**481**	**134**	**246**	**803**	**100**	**0**	**-**
5618000	REL PLN & STAND SVCS	TNEX	Transmission O&M Expense	SG	5,535	76	1,488	414	762	2,484	310	0	-
5618000 Total					**5,535**	**76**	**1,488**	**414**	**762**	**2,484**	**310**	**0**	**-**
5620000	STATION EXP(TRANS)	TNEX	Transmission O&M Expense	SG	4,697	65	1,263	352	647	2,108	263	0	-
5620000 Total					**4,697**	**65**	**1,263**	**352**	**647**	**2,108**	**263**	**0**	**-**
5630000	OVERHEAD LINE EXP	TNEX	Transmission O&M Expense	SG	1,778	24	478	133	245	798	99	0	-
5630000 Total					**1,778**	**24**	**478**	**133**	**245**	**798**	**99**	**0**	**-**
5650000	TRNS ELEC BY OTHRS	NPCX	Net Power Cost Expense	SG	4	0	1	0	1	2	0	0	-
5650000 Total					**4**	**0**	**1**	**0**	**1**	**2**	**0**	**0**	**-**
5650010	EIM - TRANSM OF ELEC	NPCX	Net Power Cost Expense	SG	2,716	37	730	203	374	1,219	152	0	-
5650010 Total					**2,716**	**37**	**730**	**203**	**374**	**1,219**	**152**	**0**	**-**
5651000	S/T FIRM WHEELING	NPCX	Net Power Cost Expense	SG	13,319	183	3,581	997	1,835	5,978	745	0	-
5651000 Total					**13,319**	**183**	**3,581**	**997**	**1,835**	**5,978**	**745**	**0**	**-**
5652500	NON-FIRM WHEEL EXP	NPCX	Net Power Cost Expense	SE	25,913	329	6,825	1,767	3,850	11,582	1,559	0	-
5652500 Total					**25,913**	**329**	**6,825**	**1,767**	**3,850**	**11,582**	**1,559**	**0**	**-**
5654600	POST-MRG WHEEL EXP	NPCX	Net Power Cost Expense	SG	125,009	1,721	33,608	9,361	17,221	56,104	6,993	0	-
5654600 Total					**125,009**	**1,721**	**33,608**	**9,361**	**17,221**	**56,104**	**6,993**	**0**	**-**
5660000	MISC TRANS EXPENSE	TNEX	Transmission O&M Expense	SG	3,976	55	1,069	298	548	1,784	222	0	-
5660000 Total					**3,976**	**55**	**1,069**	**298**	**548**	**1,784**	**222**	**0**	**-**

Operations & Maintenance Expense (Actuals)
Sum of Range: 07/2022 - 06/2023
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Group Code	Secondary Group Code Name	Alloc	Balance	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
5660010	MISC TRANS EXPENSE	TNEX	Transmission O&M Expense	SG	1	0	0	0	0	1	0	0	-
5660010 Total					**1**	**0**	**0**	**0**	**0**	**1**	**0**	**0**	**-**
5670000	RENTS-TRANSMISSION	TNEX	Transmission O&M Expense	SG	2,370	33	637	177	326	1,063	133	0	-
5670000 Total					**2,370**	**33**	**637**	**177**	**326**	**1,063**	**133**	**0**	**-**
5680000	MNT SUPERV & ENG	TNEX	Transmission O&M Expense	SG	1,287	18	346	96	177	578	72	0	-
5680000 Total					**1,287**	**18**	**346**	**96**	**177**	**578**	**72**	**0**	**-**
5690000	MAINT OF STRUCTURE	TNEX	Transmission O&M Expense	SG	188	3	50	14	26	84	11	0	-
5690000 Total					**188**	**3**	**50**	**14**	**26**	**84**	**11**	**0**	**-**
5692000	MAINT-COMP SW TRANS	TNEX	Transmission O&M Expense	SG	192	3	52	14	26	86	11	0	-
5692000 Total					**192**	**3**	**52**	**14**	**26**	**86**	**11**	**0**	**-**
5693000	MAINT-COM EQP TRANS	TNEX	Transmission O&M Expense	SG	5,847	81	1,572	438	805	2,624	327	0	-
5693000 Total					**5,847**	**81**	**1,572**	**438**	**805**	**2,624**	**327**	**0**	**-**
5700000	MAINT STATION EQIP	TNEX	Transmission O&M Expense	SG	14,058	194	3,779	1,053	1,937	6,309	786	0	-
5700000 Total					**14,058**	**194**	**3,779**	**1,053**	**1,937**	**6,309**	**786**	**0**	**-**
5710000	MAINT OVHD LINES	TNEX	Transmission O&M Expense	SG	15,825	218	4,255	1,185	2,180	7,103	885	0	-
5710000 Total					**15,825**	**218**	**4,255**	**1,185**	**2,180**	**7,103**	**885**	**0**	**-**
5720000	MNT UNDERGRD LINES	TNEX	Transmission O&M Expense	SG	165	2	44	12	23	74	9	0	-
5720000 Total					**165**	**2**	**44**	**12**	**23**	**74**	**9**	**0**	**-**
5730000	MNT MSC TRANS PLNT	TNEX	Transmission O&M Expense	SG	98	1	26	7	14	44	5	0	-
5730000 Total					**98**	**1**	**26**	**7**	**14**	**44**	**5**	**0**	**-**
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	CA	1,137	1,137	-	-	-	-	-	-	-
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	IDU	176	-	-	-	-	-	176	-	-
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	OR	1,406	-	1,406	-	-	-	-	-	-
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	SNPD	14,628	987	3,657	847	1,258	7,153	726	-	-
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	UT	469	-	-	-	-	469	-	-	-
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	WA	160	-	-	160	-	-	-	-	-
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	WYP	130	-	-	-	130	-	-	-	-
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	WYU	34	-	-	-	34	-	-	-	-
5800000 Total					**18,141**	**2,125**	**5,063**	**1,008**	**1,422**	**7,622**	**901**	**-**	**-**
5810000	LOAD DISPATCHING	DNEX	Distribution O&M Expense	SNPD	16,273	1,098	4,068	943	1,399	7,958	807	-	-
5810000 Total					**16,273**	**1,098**	**4,068**	**943**	**1,399**	**7,958**	**807**	**-**	**-**
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	CA	74	74	-	-	-	-	-	-	-
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	IDU	529	-	-	-	-	-	529	-	-
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	OR	1,100	-	1,100	-	-	-	-	-	-
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	SNPD	1	0	0	0	0	0	0	-	-
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	UT	2,523	-	-	-	-	2,523	-	-	-
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	WA	(61)	-	-	(61)	-	-	-	-	-
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	WYP	1,053	-	-	-	1,053	-	-	-	-
5820000 Total					**5,219**	**74**	**1,100**	**(61)**	**1,053**	**2,523**	**529**	**-**	**-**
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	CA	342	342	-	-	-	-	-	-	-
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	IDU	642	-	-	-	-	-	642	-	-
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	OR	2,485	-	2,485	-	-	-	-	-	-
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	UT	6,014	-	-	-	-	6,014	-	-	-
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	WA	511	-	-	511	-	-	-	-	-
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	WYP	999	-	-	-	999	-	-	-	-
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	WYU	101	-	-	-	101	-	-	-	-

Operations & Maintenance Expense (Actuals)
Sum of Range: 07/2022 - 06/2023
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Group Code	Secondary Group Code Name	Alloc	Balance	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
5830000 Total					**11,094**	**342**	**2,485**	**511**	**1,100**	**6,014**	**642**	**-**	**-**
5850000	STRT LGHT-SGNL SYS	DNEX	Distribution O&M Expense	SNPD	286	19	71	17	25	140	14	-	-
5850000 Total					**286**	**19**	**71**	**17**	**25**	**140**	**14**	**-**	**-**
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	CA	110	110	-	-	-	-	-	-	-
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	IDU	127	-	-	-	-	-	127	-	-
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	OR	1,324	-	1,324	-	-	-	-	-	-
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	UT	601	-	-	-	-	601	-	-	-
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	WA	222	-	-	222	-	-	-	-	-
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	WYP	266	-	-	-	266	-	-	-	-
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	WYU	51	-	-	-	51	-	-	-	-
5860000 Total					**2,702**	**110**	**1,324**	**222**	**318**	**601**	**127**	**-**	**-**
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	CA	523	523	-	-	-	-	-	-	-
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	IDU	1,099	-	-	-	-	-	1,099	-	-
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	OR	7,225	-	7,225	-	-	-	-	-	-
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	UT	8,924	-	-	-	-	8,924	-	-	-
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	WA	1,586	-	-	1,586	-	-	-	-	-
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	WYP	1,546	-	-	-	1,546	-	-	-	-
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	WYU	147	-	-	-	147	-	-	-	-
5870000 Total					**21,050**	**523**	**7,225**	**1,586**	**1,693**	**8,924**	**1,099**	**-**	**-**
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	CA	(14)	(14)	-	-	-	-	-	-	-
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	IDU	320	-	-	-	-	-	320	-	-
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	OR	(292)	-	(292)	-	-	-	-	-	-
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	SNPD	132	9	33	8	11	65	7	-	-
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	UT	1,449	-	-	-	-	1,449	-	-	-
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	WA	(42)	-	-	(42)	-	-	-	-	-
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	WYP	503	-	-	-	503	-	-	-	-
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	WYU	19	-	-	-	19	-	-	-	-
5880000 Total					**2,075**	**(5)**	**(259)**	**(34)**	**533**	**1,514**	**326**	**-**	**-**
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	CA	(116)	(116)	-	-	-	-	-	-	-
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	IDU	43	-	-	-	-	-	43	-	-
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	OR	1,831	-	1,831	-	-	-	-	-	-
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	SNPD	396	27	99	23	34	194	20	-	-
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	UT	666	-	-	-	-	666	-	-	-
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	WA	141	-	-	141	-	-	-	-	-
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	WYP	275	-	-	-	275	-	-	-	-
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	WYU	20	-	-	-	20	-	-	-	-
5890000 Total					**3,255**	**(89)**	**1,930**	**164**	**328**	**860**	**62**	**-**	**-**
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	CA	133	133	-	-	-	-	-	-	-
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	IDU	54	-	-	-	-	-	54	-	-
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	OR	990	-	990	-	-	-	-	-	-
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	SNPD	3,218	217	805	186	277	1,574	160	-	-
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	UT	(6,975)	-	-	-	-	(6,975)	-	-	-
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	WA	260	-	-	260	-	-	-	-	-
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	WYP	261	-	-	-	261	-	-	-	-
5900000 Total					**(2,059)**	**350**	**1,795**	**446**	**538**	**(5,401)**	**214**	**-**	**-**
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	CA	51	51	-	-	-	-	-	-	-

PACIFICORP

Operations & Maintenance Expense (Actuals)
Sum of Range: 07/2022 - 06/2023
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Group Code	Secondary Group Code Name	Alloc	Balance	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	IDU	114	-	-	-	-	-	114	-	-
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	OR	689	-	689	-	-	-	-	-	-
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	SNPD	84	6	21	5	7	41	4	-	-
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	UT	804	-	-	-	-	804	-	-	-
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	WA	154	-	-	154	-	-	-	-	-
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	WYP	195	-	-	-	195	-	-	-	-
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	WYU	58	-	-	-	58	-	-	-	-
5910000 Total					**2,149**	**57**	**710**	**158**	**261**	**845**	**118**	**-**	**-**
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	CA	317	317	-	-	-	-	-	-	-
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	IDU	693	-	-	-	-	-	693	-	-
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	OR	3,274	-	3,274	-	-	-	-	-	-
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	SNPD	956	65	239	55	82	468	47	-	-
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	UT	2,492	-	-	-	-	2,492	-	-	-
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	WA	1,105	-	-	1,105	-	-	-	-	-
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	WYP	1,201	-	-	-	1,201	-	-	-	-
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	WYU	34	-	-	-	34	-	-	-	-
5920000 Total					**10,072**	**381**	**3,513**	**1,160**	**1,317**	**2,959**	**740**	**-**	**-**
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	CA	19,336	19,336	-	-	-	-	-	-	-
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	IDU	4,412	-	-	-	-	-	4,412	-	-
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	OR	65,047	-	65,047	-	-	-	-	-	-
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	SNPD	3,289	222	822	191	283	1,609	163	-	-
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	UT	34,853	-	-	-	-	34,853	-	-	-
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	WA	7,403	-	-	7,403	-	-	-	-	-
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	WYP	6,544	-	-	-	6,544	-	-	-	-
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	WYU	1,542	-	-	-	1,542	-	-	-	-
5930000 Total					**142,426**	**19,558**	**65,869**	**7,593**	**8,368**	**36,462**	**4,575**	**-**	**-**
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	CA	(383)	(383)	-	-	-	-	-	-	-
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	IDU	290	-	-	-	-	-	290	-	-
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	OR	(2,475)	-	(2,475)	-	-	-	-	-	-
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	UT	2,532	-	-	-	-	2,532	-	-	-
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	WA	(531)	-	-	(531)	-	-	-	-	-
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	WYP	399	-	-	-	399	-	-	-	-
5931000 Total					**(169)**	**(383)**	**(2,475)**	**(531)**	**399**	**2,532**	**290**	**-**	**-**
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	CA	865	865	-	-	-	-	-	-	-
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	IDU	1,082	-	-	-	-	-	1,082	-	-
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	OR	9,370	-	9,370	-	-	-	-	-	-
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	SNPD	9	1	2	1	1	5	0	-	-
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	UT	24,699	-	-	-	-	24,699	-	-	-
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	WA	2,122	-	-	2,122	-	-	-	-	-
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	WYP	1,885	-	-	-	1,885	-	-	-	-
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	WYU	323	-	-	-	323	-	-	-	-
5940000 Total					**40,355**	**865**	**9,373**	**2,122**	**2,209**	**24,704**	**1,082**	**-**	**-**
5950000	MAINT LINE TRNSFRM	DNEX	Distribution O&M Expense	SNPD	1,057	71	264	61	91	517	52	-	-
5950000 Total					**1,057**	**71**	**264**	**61**	**91**	**517**	**52**	**-**	**-**
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	CA	72	72	-	-	-	-	-	-	-
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	IDU	61	-	-	-	-	-	61	-	-

PACIFICORP

Operations & Maintenance Expense (Actuals)
Sum of Range: 07/2022 - 06/2023
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Group Code	Secondary Group Code Name	Alloc	Balance	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	OR	773	-	773	-	-	-	-	-	-
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	UT	877	-	-	-	-	877	-	-	-
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	WA	112	-	-	112	-	-	-	-	-
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	WYP	350	-	-	-	350	-	-	-	-
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	WYU	107	-	-	-	107	-	-	-	-
5960000 Total					**2,351**	**72**	**773**	**112**	**456**	**877**	**61**	**-**	**-**
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	CA	15	15	-	-	-	-	-	-	-
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	IDU	45	-	-	-	-	-	45	-	-
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	OR	172	-	172	-	-	-	-	-	-
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	SNPD	(29)	(2)	(7)	(2)	(2)	(14)	(1)	-	-
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	UT	302	-	-	-	-	302	-	-	-
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	WA	17	-	-	17	-	-	-	-	-
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	WYP	28	-	-	-	28	-	-	-	-
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	WYU	11	-	-	-	11	-	-	-	-
5970000 Total					**561**	**13**	**165**	**15**	**37**	**287**	**44**	**-**	**-**
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	CA	66	66	-	-	-	-	-	-	-
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	IDU	83	-	-	-	-	-	83	-	-
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	OR	695	-	695	-	-	-	-	-	-
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	SNPD	899	61	225	52	77	440	45	-	-
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	UT	868	-	-	-	-	868	-	-	-
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	WA	149	-	-	149	-	-	-	-	-
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	WYP	303	-	-	-	303	-	-	-	-
5980000 Total					**3,064**	**126**	**920**	**201**	**381**	**1,308**	**127**	**-**	**-**
5989500	MNT DIST PLNT-ENV AM	DNEX	Distribution O&M Expense	SNPD	2,700	182	675	156	232	1,321	134	-	-
5989500 Total					**2,700**	**182**	**675**	**156**	**232**	**1,321**	**134**	**-**	**-**
9010000	SUPRV (CUST ACCT)	CAEX	Customer Accounting Expense	CN	2,982	68	916	200	212	1,461	127	-	-
9010000	SUPRV (CUST ACCT)	CAEX	Customer Accounting Expense	WYP	0	-	-	-	0	-	-	-	-
9010000 Total					**2,983**	**68**	**916**	**200**	**212**	**1,461**	**127**	**-**	**-**
9020000	METER READING EXP	CAEX	Customer Accounting Expense	CA	464	464	-	-	-	-	-	-	-
9020000	METER READING EXP	CAEX	Customer Accounting Expense	CN	731	17	224	49	52	358	31	-	-
9020000	METER READING EXP	CAEX	Customer Accounting Expense	IDU	825	-	-	-	-	-	825	-	-
9020000	METER READING EXP	CAEX	Customer Accounting Expense	OR	2,002	-	2,002	-	-	-	-	-	-
9020000	METER READING EXP	CAEX	Customer Accounting Expense	UT	5,489	-	-	-	-	5,489	-	-	-
9020000	METER READING EXP	CAEX	Customer Accounting Expense	WA	1,040	-	-	1,040	-	-	-	-	-
9020000	METER READING EXP	CAEX	Customer Accounting Expense	WYP	1,123	-	-	-	1,123	-	-	-	-
9020000	METER READING EXP	CAEX	Customer Accounting Expense	WYU	236	-	-	-	236	-	-	-	-
9020000 Total					**11,909**	**481**	**2,227**	**1,089**	**1,410**	**5,847**	**856**	**-**	**-**
9030000	CUST RCRD/COLL EXP	CAEX	Customer Accounting Expense	CN	1,222	28	375	82	87	599	52	-	-
9030000 Total					**1,222**	**28**	**375**	**82**	**87**	**599**	**52**	**-**	**-**
9031000	CUST RCRD/CUST SYS	CAEX	Customer Accounting Expense	CN	2,203	50	677	147	156	1,080	94	-	-
9031000 Total					**2,203**	**50**	**677**	**147**	**156**	**1,080**	**94**	**-**	**-**
9032000	CUST ACCTG/BILL	CAEX	Customer Accounting Expense	CN	9,430	214	2,896	631	669	4,620	400	-	-
9032000	CUST ACCTG/BILL	CAEX	Customer Accounting Expense	OR	0	-	0	-	-	-	-	-	-
9032000	CUST ACCTG/BILL	CAEX	Customer Accounting Expense	UT	5	-	-	-	-	5	-	-	-
9032000 Total					**9,435**	**214**	**2,896**	**631**	**669**	**4,625**	**400**	**-**	**-**
9033000	CUST ACCTG/COLL	CAEX	Customer Accounting Expense	CA	12	12	-	-	-	-	-	-	-

PACIFICORP

Operations & Maintenance Expense (Actuals)
Sum of Range: 07/2022 - 06/2023
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Group Code	Secondary Group Code Name	Alloc	Balance	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
9033000	CUST ACCTG/COLL	CAEX	Customer Accounting Expense	CN	16,643	377	5,110	1,114	1,181	8,154	706	-	-
9033000	CUST ACCTG/COLL	CAEX	Customer Accounting Expense	IDU	147	-	-	-	-	-	147	-	-
9033000	CUST ACCTG/COLL	CAEX	Customer Accounting Expense	OR	492	-	492	-	-	-	-	-	-
9033000	CUST ACCTG/COLL	CAEX	Customer Accounting Expense	UT	1,036	-	-	-	-	1,036	-	-	-
9033000	CUST ACCTG/COLL	CAEX	Customer Accounting Expense	WA	169	-	-	169	-	-	-	-	-
9033000	CUST ACCTG/COLL	CAEX	Customer Accounting Expense	WYP	366	-	-	-	366	-	-	-	-
9033000	CUST ACCTG/COLL	CAEX	Customer Accounting Expense	WYU	33	-	-	-	33	-	-	-	-
9033000 Total					**18,897**	**388**	**5,602**	**1,282**	**1,580**	**9,191**	**853**	**-**	**-**
9035000	CUST ACCTG/REQ	CAEX	Customer Accounting Expense	CA	16	16	-	-	-	-	-	-	-
9035000	CUST ACCTG/REQ	CAEX	Customer Accounting Expense	IDU	27	-	-	-	-	-	27	-	-
9035000	CUST ACCTG/REQ	CAEX	Customer Accounting Expense	OR	92	-	92	-	-	-	-	-	-
9035000	CUST ACCTG/REQ	CAEX	Customer Accounting Expense	UT	87	-	-	-	-	87	-	-	-
9035000	CUST ACCTG/REQ	CAEX	Customer Accounting Expense	WA	32	-	-	32	-	-	-	-	-
9035000	CUST ACCTG/REQ	CAEX	Customer Accounting Expense	WYP	11	-	-	-	11	-	-	-	-
9035000	CUST ACCTG/REQ	CAEX	Customer Accounting Expense	WYU	7	-	-	-	7	-	-	-	-
9035000 Total					**271**	**16**	**92**	**32**	**18**	**87**	**27**	**-**	**-**
9036000	CUST ACCTG/COMMON	CAEX	Customer Accounting Expense	CN	9,426	213	2,894	631	669	4,618	400	-	-
9036000	CUST ACCTG/COMMON	CAEX	Customer Accounting Expense	OR	11	-	11	-	-	-	-	-	-
9036000	CUST ACCTG/COMMON	CAEX	Customer Accounting Expense	WA	485	-	-	485	-	-	-	-	-
9036000	CUST ACCTG/COMMON	CAEX	Customer Accounting Expense	OR	(1)	-	(1)	-	-	-	-	-	-
9036000 Total					**9,921**	**213**	**2,904**	**1,116**	**669**	**4,618**	**400**	**-**	**-**
9040000	UNCOLLECT ACCOUNTS	CAEX	Customer Accounting Expense	CA	782	782	-	-	-	-	-	-	-
9040000	UNCOLLECT ACCOUNTS	CAEX	Customer Accounting Expense	CN	(916)	(21)	(281)	(61)	(65)	(449)	(39)	-	-
9040000	UNCOLLECT ACCOUNTS	CAEX	Customer Accounting Expense	IDU	509	-	-	-	-	-	509	-	-
9040000	UNCOLLECT ACCOUNTS	CAEX	Customer Accounting Expense	OR	8,618	-	8,618	-	-	-	-	-	-
9040000	UNCOLLECT ACCOUNTS	CAEX	Customer Accounting Expense	UT	6,569	-	-	-	-	6,569	-	-	-
9040000	UNCOLLECT ACCOUNTS	CAEX	Customer Accounting Expense	WA	6,980	-	-	6,980	-	-	-	-	-
9040000	UNCOLLECT ACCOUNTS	CAEX	Customer Accounting Expense	WYP	1,382	-	-	-	1,382	-	-	-	-
9040000 Total					**23,924**	**762**	**8,336**	**6,919**	**1,317**	**6,120**	**470**	**-**	**-**
9042000	UNCOLL ACCTS-JOINT U	CAEX	Customer Accounting Expense	CA	(0)	(0)	-	-	-	-	-	-	-
9042000	UNCOLL ACCTS-JOINT U	CAEX	Customer Accounting Expense	IDU	(0)	-	-	-	-	-	(0)	-	-
9042000	UNCOLL ACCTS-JOINT U	CAEX	Customer Accounting Expense	OR	(33)	-	(33)	-	-	-	-	-	-
9042000	UNCOLL ACCTS-JOINT U	CAEX	Customer Accounting Expense	UT	64	-	-	-	-	64	-	-	-
9042000	UNCOLL ACCTS-JOINT U	CAEX	Customer Accounting Expense	WA	7	-	-	7	-	-	-	-	-
9042000	UNCOLL ACCTS-JOINT U	CAEX	Customer Accounting Expense	WYP	(12)	-	-	-	(12)	-	-	-	-
9042000 Total					**26**	**(0)**	**(33)**	**7**	**(12)**	**64**	**(0)**	**-**	**-**
9050000	MISC CUST ACCT EXP	CAEX	Customer Accounting Expense	CN	0	0	0	0	0	0	0	-	-
9050000	MISC CUST ACCT EXP	CAEX	Customer Accounting Expense	OR	(0)	-	(0)	-	-	-	-	-	-
9050000	MISC CUST ACCT EXP	CAEX	Customer Accounting Expense	WYP	0	-	-	-	0	-	-	-	-
9050000 Total					**0**	**0**	**0**	**0**	**0**	**0**	**0**	**-**	**-**
9070000	SUPRV (CUST SERV)	CSEX	Customer Service Expense	CN	1	0	0	0	0	1	0	-	-
9070000 Total					**1**	**0**	**0**	**0**	**0**	**1**	**0**	**-**	**-**
9080000	CUST ASSIST EXP	CSEX	Customer Service Expense	CN	5	0	2	0	0	3	0	-	-
9080000	CUST ASSIST EXP	CSEX	Customer Service Expense	OR	1	-	1	-	-	-	-	-	-
9080000	CUST ASSIST EXP	CSEX	Customer Service Expense	UT	1	-	-	-	-	1	-	-	-
9080000 Total					**8**	**0**	**3**	**0**	**0**	**4**	**0**	**-**	**-**

PACIFICORP

Operations & Maintenance Expense (Actuals)
Sum of Range: 07/2022 - 06/2023
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Group Code	Secondary Group Code Name	Alloc	Balance	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
9081000	CUST ASST EXP-GENL	CSEX	Customer Service Expense	CN	717	16	220	48	51	351	30	-	-
9081000	CUST ASST EXP-GENL	CSEX	Customer Service Expense	OTHER	5,021	-	-	-	-	-	-	-	5,021
9081000	CUST ASST EXP-GENL	CSEX	Customer Service Expense	UT	364	-	-	-	-	364	-	-	-
9081000 Total					**6,103**	**16**	**220**	**48**	**51**	**715**	**30**	**-**	**5,021**
9084000	DSM DIRECT	CSEX	Customer Service Expense	CA	(75)	(75)	-	-	-	-	-	-	-
9084000	DSM DIRECT	CSEX	Customer Service Expense	CN	2,325	53	714	156	165	1,139	99	-	-
9084000	DSM DIRECT	CSEX	Customer Service Expense	OTHER	155	-	-	-	-	-	-	-	155
9084000	DSM DIRECT	CSEX	Customer Service Expense	UT	0	-	-	-	-	0	-	-	-
9084000	DSM DIRECT	CSEX	Customer Service Expense	WA	58	-	-	58	-	-	-	-	-
9084000	DSM DIRECT	CSEX	Customer Service Expense	WYP	1	-	-	-	1	-	-	-	-
9084000 Total					**2,464**	**(22)**	**714**	**213**	**166**	**1,139**	**99**	**-**	**155**
9085100	DSM AMORT-SBC/ECC	CSEX	Customer Service Expense	OTHER	125,866	-	-	-	-	-	-	-	125,866
9085100 Total					**125,866**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**125,866**
9086000	CUST SERV	CSEX	Customer Service Expense	CN	170	4	52	11	12	83	7	-	-
9086000	CUST SERV	CSEX	Customer Service Expense	IDU	17	-	-	-	-	-	17	-	-
9086000	CUST SERV	CSEX	Customer Service Expense	OR	2,367	-	2,367	-	-	-	-	-	-
9086000	CUST SERV	CSEX	Customer Service Expense	UT	3,058	-	-	-	-	3,058	-	-	-
9086000	CUST SERV	CSEX	Customer Service Expense	WA	172	-	-	172	-	-	-	-	-
9086000	CUST SERV	CSEX	Customer Service Expense	WYP	1,001	-	-	-	1,001	-	-	-	-
9086000 Total					**6,783**	**4**	**2,419**	**183**	**1,013**	**3,141**	**24**	**-**	**-**
9089300	ENERGY STORAGE	CSEX	Customer Service Expense	OTHER	184	-	-	-	-	-	-	-	184
9089300 Total					**184**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**184**
9089500	BLUE SKY EXPENSE	CSEX	Customer Service Expense	OTHER	6,836	-	-	-	-	-	-	-	6,836
9089500 Total					**6,836**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**6,836**
9089600	SOLAR FEED-IN EXP	CSEX	Customer Service Expense	OTHER	4,445	-	-	-	-	-	-	-	4,445
9089600 Total					**4,445**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**4,445**
9089700	SUBSCRIBER SOLAR	CSEX	Customer Service Expense	UT	170	-	-	-	-	170	-	-	-
9089700 Total					**170**	**-**	**-**	**-**	**-**	**170**	**-**	**-**	**-**
9089800	COMMUNITY SOLAR	CSEX	Customer Service Expense	OTHER	483	-	-	-	-	-	-	-	483
9089800 Total					**483**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**483**
9090000	INFOR/INSTRCT ADV	CSEX	Customer Service Expense	CA	123	123	-	-	-	-	-	-	-
9090000	INFOR/INSTRCT ADV	CSEX	Customer Service Expense	CN	3,578	81	1,099	239	254	1,753	152	-	-
9090000	INFOR/INSTRCT ADV	CSEX	Customer Service Expense	IDU	187	-	-	-	-	-	187	-	-
9090000	INFOR/INSTRCT ADV	CSEX	Customer Service Expense	OR	459	-	459	-	-	-	-	-	-
9090000	INFOR/INSTRCT ADV	CSEX	Customer Service Expense	UT	783	-	-	-	-	783	-	-	-
9090000	INFOR/INSTRCT ADV	CSEX	Customer Service Expense	WA	227	-	-	227	-	-	-	-	-
9090000	INFOR/INSTRCT ADV	CSEX	Customer Service Expense	WYP	272	-	-	-	272	-	-	-	-
9090000 Total					**5,629**	**204**	**1,557**	**466**	**526**	**2,536**	**339**	**-**	**-**
9100000	MISC CUST SERV/INF	CSEX	Customer Service Expense	CN	9	0	3	1	1	4	0	-	-
9100000 Total					**9**	**0**	**3**	**1**	**1**	**4**	**0**	**-**	**-**
9200000	ADMIN & GEN SALARY	AGEX	Administrative & General Expense	OR	(616)	-	(616)	-	-	-	-	-	-
9200000	ADMIN & GEN SALARY	AGEX	Administrative & General Expense	SO	81,072	2,127	22,234	5,932	10,310	36,049	4,420	0	-
9200000	ADMIN & GEN SALARY	AGEX	Administrative & General Expense	UT	0	-	-	-	-	0	-	-	-
9200000	ADMIN & GEN SALARY	AGEX	Administrative & General Expense	WA	0	-	-	0	-	-	-	-	-
9200000	ADMIN & GEN SALARY	AGEX	Administrative & General Expense	WYP	0	-	-	-	0	-	-	-	-
9200000 Total					**80,456**	**2,127**	**21,619**	**5,932**	**10,310**	**36,049**	**4,420**	**0**	**-**

PACIFICORP

Operations & Maintenance Expense (Actuals)
Sum of Range: 07/2022 - 06/2023
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Group Code	Secondary Group Code Name	Alloc	Balance	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
9210000	OFFICE SUPPL & EXP	AGEX	Administrative & General Expense	CA	6	6	-	-	-	-	-	-	-
9210000	OFFICE SUPPL & EXP	AGEX	Administrative & General Expense	CN	131	3	40	9	9	64	6	-	-
9210000	OFFICE SUPPL & EXP	AGEX	Administrative & General Expense	IDU	2	-	-	-	-	-	2	-	-
9210000	OFFICE SUPPL & EXP	AGEX	Administrative & General Expense	OR	(5)	-	(5)	-	-	-	-	-	-
9210000	OFFICE SUPPL & EXP	AGEX	Administrative & General Expense	SO	16,880	443	4,630	1,235	2,147	7,506	920	0	-
9210000	OFFICE SUPPL & EXP	AGEX	Administrative & General Expense	UT	513	-	-	-	-	513	-	-	-
9210000	OFFICE SUPPL & EXP	AGEX	Administrative & General Expense	WA	8	-	-	8	-	-	-	-	-
9210000	OFFICE SUPPL & EXP	AGEX	Administrative & General Expense	WYP	10	-	-	-	10	-	-	-	-
9210000	OFFICE SUPPL & EXP	AGEX	Administrative & General Expense	WYU	3	-	-	-	3	-	-	-	-
9210000	OFFICE SUPPL & EXP	AGEX	Administrative & General Expense	SO	3	0	1	0	0	1	0	0	-
9210000 Total					**17,551**	**452**	**4,666**	**1,252**	**2,169**	**8,085**	**928**	**0**	**-**
9220000	A&G EXP TRANSF-CR	AGEX	Administrative & General Expense	SO	(48,438)	(1,271)	(13,284)	(3,544)	(6,160)	(21,538)	(2,641)	(0)	-
9220000 Total					**(48,438)**	**(1,271)**	**(13,284)**	**(3,544)**	**(6,160)**	**(21,538)**	**(2,641)**	**(0)**	**-**
9230000	OUTSIDE SERVICES	AGEX	Administrative & General Expense	CA	55	55	-	-	-	-	-	-	-
9230000	OUTSIDE SERVICES	AGEX	Administrative & General Expense	IDU	0	-	-	-	-	-	0	-	-
9230000	OUTSIDE SERVICES	AGEX	Administrative & General Expense	OR	799	-	799	-	-	-	-	-	-
9230000	OUTSIDE SERVICES	AGEX	Administrative & General Expense	SO	27,050	710	7,419	1,979	3,440	12,028	1,475	0	-
9230000	OUTSIDE SERVICES	AGEX	Administrative & General Expense	UT	1,102	-	-	-	-	1,102	-	-	-
9230000	OUTSIDE SERVICES	AGEX	Administrative & General Expense	WA	0	-	-	0	-	-	-	-	-
9230000	OUTSIDE SERVICES	AGEX	Administrative & General Expense	WYP	671	-	-	-	671	-	-	-	-
9230000	OUTSIDE SERVICES	AGEX	Administrative & General Expense	WYU	408	-	-	-	408	-	-	-	-
9230000 Total					**30,086**	**765**	**8,217**	**1,979**	**4,520**	**13,130**	**1,475**	**0**	**-**
9239990	AFFL SERV EMPLOYED	AGEX	Administrative & General Expense	CA	(2)	(2)	-	-	-	-	-	-	-
9239990	AFFL SERV EMPLOYED	AGEX	Administrative & General Expense	IDU	1	-	-	-	-	-	1	-	-
9239990	AFFL SERV EMPLOYED	AGEX	Administrative & General Expense	OR	19	-	19	-	-	-	-	-	-
9239990	AFFL SERV EMPLOYED	AGEX	Administrative & General Expense	SO	22,252	584	6,103	1,628	2,830	9,894	1,213	0	-
9239990	AFFL SERV EMPLOYED	AGEX	Administrative & General Expense	UT	11	-	-	-	-	11	-	-	-
9239990	AFFL SERV EMPLOYED	AGEX	Administrative & General Expense	WYP	5	-	-	-	5	-	-	-	-
9239990 Total					**22,286**	**582**	**6,122**	**1,628**	**2,835**	**9,905**	**1,215**	**0**	**-**
9241000	PROP INS-ACCRL SITUS	AGEX	Administrative & General Expense	CA	1,989	1,989	-	-	-	-	-	-	-
9241000	PROP INS-ACCRL SITUS	AGEX	Administrative & General Expense	OR	10,802	-	10,802	-	-	-	-	-	-
9241000	PROP INS-ACCRL SITUS	AGEX	Administrative & General Expense	UT	474	-	-	-	-	474	-	-	-
9241000	PROP INS-ACCRL SITUS	AGEX	Administrative & General Expense	WA	1,145	-	-	1,145	-	-	-	-	-
9241000	PROP INS-ACCRL SITUS	AGEX	Administrative & General Expense	WYP	13	-	-	-	13	-	-	-	-
9241000 Total					**14,422**	**1,989**	**10,802**	**1,145**	**13**	**474**	**-**	**-**	**-**
9242000	PROP INS-CLAIM SITUS	AGEX	Administrative & General Expense	CA	488	488	-	-	-	-	-	-	-
9242000	PROP INS-CLAIM SITUS	AGEX	Administrative & General Expense	OR	(315)	-	(315)	-	-	-	-	-	-
9242000	PROP INS-CLAIM SITUS	AGEX	Administrative & General Expense	WA	(93)	-	-	(93)	-	-	-	-	-
9242000 Total					**80**	**488**	**(315)**	**(93)**	**-**	**-**	**-**	**-**	**-**
9243000	PROP INS - PREMIUMS	AGEX	Administrative & General Expense	SO	5,050	132	1,385	369	642	2,245	275	0	-
9243000 Total					**5,050**	**132**	**1,385**	**369**	**642**	**2,245**	**275**	**0**	**-**
9250000	INJURIES & DAMAGES	AGEX	Administrative & General Expense	SO	456,920	11,987	125,312	33,430	58,109	203,169	24,913	0	-
9250000 Total					**456,920**	**11,987**	**125,312**	**33,430**	**58,109**	**203,169**	**24,913**	**0**	**-**
9251000	INJURIES & DAMAGES	AGEX	Administrative & General Expense	OR	(8,898)	-	(8,898)	-	-	-	-	-	-
9251000	INJURIES & DAMAGES	AGEX	Administrative & General Expense	SO	8,898	233	2,440	651	1,132	3,957	485	0	-
9251000 Total					**-**	**233**	**(6,458)**	**651**	**1,132**	**3,957**	**485**	**0**	**-**

PACIFICORP

Operations & Maintenance Expense (Actuals)
Sum of Range: 07/2022 - 06/2023
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Group Code	Secondary Group Code Name	Alloc	Balance	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
9261200	PEN EXP-OTH NBC	AGEX	Administrative & General Expense	SO	20,354	534	5,582	1,489	2,589	9,050	1,110	0	-
9261200 Total					**20,354**	**534**	**5,582**	**1,489**	**2,589**	**9,050**	**1,110**	**0**	**-**
9261500	PEN EXP-STATE SITUS	AGEX	Administrative & General Expense	CA	(482)	(482)	-	-	-	-	-	-	-
9261500	PEN EXP-STATE SITUS	AGEX	Administrative & General Expense	OR	(6,510)	-	(6,510)	-	-	-	-	-	-
9261500	PEN EXP-STATE SITUS	AGEX	Administrative & General Expense	SO	(81)	(2)	(22)	(6)	(10)	(36)	(4)	(0)	-
9261500	PEN EXP-STATE SITUS	AGEX	Administrative & General Expense	UT	(2,951)	-	-	-	-	(2,951)	-	-	-
9261500	PEN EXP-STATE SITUS	AGEX	Administrative & General Expense	WA	(1,726)	-	-	(1,726)	-	-	-	-	-
9261500	PEN EXP-STATE SITUS	AGEX	Administrative & General Expense	WYP	(3,018)	-	-	-	(3,018)	-	-	-	-
9261500 Total					**(14,768)**	**(484)**	**(6,532)**	**(1,732)**	**(3,028)**	**(2,987)**	**(4)**	**(0)**	**-**
9262200	POSTRET EXP-OTH NBC	AGEX	Administrative & General Expense	SO	(3,685)	(97)	(1,011)	(270)	(469)	(1,639)	(201)	(0)	-
9262200 Total					**(3,685)**	**(97)**	**(1,011)**	**(270)**	**(469)**	**(1,639)**	**(201)**	**(0)**	**-**
9262500	POSTRET EXP-ST SITUS	AGEX	Administrative & General Expense	IDU	174	-	-	-	-	-	174	-	-
9262500	POSTRET EXP-ST SITUS	AGEX	Administrative & General Expense	OR	776	-	776	-	-	-	-	-	-
9262500 Total					**950**	**-**	**776**	**-**	**-**	**-**	**174**	**-**	**-**
9263200	SERP EXP-OTH NBC	AGEX	Administrative & General Expense	SO	2,772	73	760	203	352	1,232	151	0	-
9263200 Total					**2,772**	**73**	**760**	**203**	**352**	**1,232**	**151**	**0**	**-**
9269100	GROSS-UP - PENSION	AGEX	Administrative & General Expense	SO	6,448	169	1,768	472	820	2,867	352	0	-
9269100 Total					**6,448**	**169**	**1,768**	**472**	**820**	**2,867**	**352**	**0**	**-**
9269200	GROSS-UP - POST-RETR	AGEX	Administrative & General Expense	SO	(452)	(12)	(124)	(33)	(57)	(201)	(25)	(0)	-
9269200 Total					**(452)**	**(12)**	**(124)**	**(33)**	**(57)**	**(201)**	**(25)**	**(0)**	**-**
9269400	GROSS-UP - MD/DN/V/L	AGEX	Administrative & General Expense	SO	62,493	1,639	17,139	4,572	7,948	27,787	3,407	0	-
9269400 Total					**62,493**	**1,639**	**17,139**	**4,572**	**7,948**	**27,787**	**3,407**	**0**	**-**
9269500	GROSS-UP - 401(K) EX	AGEX	Administrative & General Expense	SO	45,269	1,188	12,415	3,312	5,757	20,129	2,468	0	-
9269500 Total					**45,269**	**1,188**	**12,415**	**3,312**	**5,757**	**20,129**	**2,468**	**0**	**-**
9269600	GROSS-UP - POST-EMPL	AGEX	Administrative & General Expense	SO	5,222	137	1,432	382	664	2,322	285	0	-
9269600 Total					**5,222**	**137**	**1,432**	**382**	**664**	**2,322**	**285**	**0**	**-**
9269700	GROSS-UP - OTH BEN E	AGEX	Administrative & General Expense	SO	5,933	156	1,627	434	755	2,638	323	0	-
9269700 Total					**5,933**	**156**	**1,627**	**434**	**755**	**2,638**	**323**	**0**	**-**
9280000	REGULATORY COM EXP	AGEX	Administrative & General Expense	CA	803	803	-	-	-	-	-	-	-
9280000	REGULATORY COM EXP	AGEX	Administrative & General Expense	OR	1,698	-	1,698	-	-	-	-	-	-
9280000	REGULATORY COM EXP	AGEX	Administrative & General Expense	SO	1,691	44	464	124	215	752	92	0	-
9280000	REGULATORY COM EXP	AGEX	Administrative & General Expense	UT	209	-	-	-	-	209	-	-	-
9280000	REGULATORY COM EXP	AGEX	Administrative & General Expense	WA	507	-	-	507	-	-	-	-	-
9280000	REGULATORY COM EXP	AGEX	Administrative & General Expense	WYP	422	-	-	-	422	-	-	-	-
9280000 Total					**5,329**	**847**	**2,162**	**630**	**637**	**960**	**92**	**0**	**-**
9282000	REG COMM EXPENSE	AGEX	Administrative & General Expense	CA	61	61	-	-	-	-	-	-	-
9282000	REG COMM EXPENSE	AGEX	Administrative & General Expense	IDU	587	-	-	-	-	-	587	-	-
9282000	REG COMM EXPENSE	AGEX	Administrative & General Expense	OR	5,090	-	5,090	-	-	-	-	-	-
9282000	REG COMM EXPENSE	AGEX	Administrative & General Expense	SO	1	0	0	0	0	0	0	0	-
9282000	REG COMM EXPENSE	AGEX	Administrative & General Expense	UT	6,774	-	-	-	-	6,774	-	-	-
9282000	REG COMM EXPENSE	AGEX	Administrative & General Expense	WA	1,609	-	-	1,609	-	-	-	-	-
9282000	REG COMM EXPENSE	AGEX	Administrative & General Expense	WYP	1,455	-	-	-	1,455	-	-	-	-
9282000 Total					**15,578**	**61**	**5,090**	**1,609**	**1,455**	**6,775**	**587**	**0**	**-**
9283000	FERC FILING FEE	AGEX	Administrative & General Expense	SG	6,382	88	1,716	478	879	2,864	357	0	-
9283000 Total					**6,382**	**88**	**1,716**	**478**	**879**	**2,864**	**357**	**0**	**-**
9290000	DUPLICATE CHRGS-CR	AGEX	Administrative & General Expense	SO	(10,326)	(271)	(2,832)	(755)	(1,313)	(4,591)	(563)	(0)	-

PACIFICORP

Operations & Maintenance Expense (Actuals)
Sum of Range: 07/2022 - 06/2023
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account	Primary Account Name	Secondary Group Code	Secondary Group Code Name	Alloc	Balance	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
9290000 Total					**(10,326)**	**(271)**	**(2,832)**	**(755)**	**(1,313)**	**(4,591)**	**(563)**	**(0)**	**-**
9299100	DUP CHG CR - PENSION	AGEX	Administrative & General Expense	SO	(6,448)	(169)	(1,768)	(472)	(820)	(2,867)	(352)	(0)	-
9299100 Total					**(6,448)**	**(169)**	**(1,768)**	**(472)**	**(820)**	**(2,867)**	**(352)**	**(0)**	**-**
9299200	DUP CHG CR - POST-RT	AGEX	Administrative & General Expense	SO	452	12	124	33	57	201	25	0	-
9299200 Total					**452**	**12**	**124**	**33**	**57**	**201**	**25**	**0**	**-**
9299400	DUP CHG CR - M/D/V/L	AGEX	Administrative & General Expense	SO	(62,493)	(1,639)	(17,139)	(4,572)	(7,948)	(27,787)	(3,407)	(0)	-
9299400 Total					**(62,493)**	**(1,639)**	**(17,139)**	**(4,572)**	**(7,948)**	**(27,787)**	**(3,407)**	**(0)**	**-**
9299500	DUP CHRG CR - 401(K)	AGEX	Administrative & General Expense	SO	(45,269)	(1,188)	(12,415)	(3,312)	(5,757)	(20,129)	(2,468)	(0)	-
9299500 Total					**(45,269)**	**(1,188)**	**(12,415)**	**(3,312)**	**(5,757)**	**(20,129)**	**(2,468)**	**(0)**	**-**
9299600	DUP CHG CR - POST-EM	AGEX	Administrative & General Expense	SO	(5,222)	(137)	(1,432)	(382)	(664)	(2,322)	(285)	(0)	-
9299600 Total					**(5,222)**	**(137)**	**(1,432)**	**(382)**	**(664)**	**(2,322)**	**(285)**	**(0)**	**-**
9299700	DUP CHG CR - OTH BEN	AGEX	Administrative & General Expense	SO	(5,933)	(156)	(1,627)	(434)	(755)	(2,638)	(323)	(0)	-
9299700 Total					**(5,933)**	**(156)**	**(1,627)**	**(434)**	**(755)**	**(2,638)**	**(323)**	**(0)**	**-**
9301000	GEN ADVERTISNG EXP	AGEX	Administrative & General Expense	SO	34	1	9	2	4	15	2	0	-
9301000 Total					**34**	**1**	**9**	**2**	**4**	**15**	**2**	**0**	**-**
9302000	MISC GEN EXP-OTHER	AGEX	Administrative & General Expense	CA	1	1	-	-	-	-	-	-	-
9302000	MISC GEN EXP-OTHER	AGEX	Administrative & General Expense	OR	0	-	0	-	-	-	-	-	-
9302000	MISC GEN EXP-OTHER	AGEX	Administrative & General Expense	SO	2,686	70	737	196	342	1,194	146	0	-
9302000	MISC GEN EXP-OTHER	AGEX	Administrative & General Expense	UT	56	-	-	-	-	56	-	-	-
9302000	MISC GEN EXP-OTHER	AGEX	Administrative & General Expense	WYP	63	-	-	-	63	-	-	-	-
9302000 Total					**2,805**	**71**	**737**	**196**	**405**	**1,250**	**146**	**0**	**-**
9310000	RENTS (A&G)	AGEX	Administrative & General Expense	CA	64	64	-	-	-	-	-	-	-
9310000	RENTS (A&G)	AGEX	Administrative & General Expense	IDU	0	-	-	-	-	-	0	-	-
9310000	RENTS (A&G)	AGEX	Administrative & General Expense	OR	283	-	283	-	-	-	-	-	-
9310000	RENTS (A&G)	AGEX	Administrative & General Expense	SO	(4,052)	(106)	(1,111)	(296)	(515)	(1,802)	(221)	(0)	-
9310000	RENTS (A&G)	AGEX	Administrative & General Expense	UT	2	-	-	-	-	2	-	-	-
9310000	RENTS (A&G)	AGEX	Administrative & General Expense	WA	16	-	-	16	-	-	-	-	-
9310000	RENTS (A&G)	AGEX	Administrative & General Expense	WYP	8	-	-	-	8	-	-	-	-
9310000 Total					**(3,679)**	**(42)**	**(828)**	**(281)**	**(507)**	**(1,800)**	**(221)**	**(0)**	**-**
9350000	MAINT GENERAL PLNT	AGEX	Administrative & General Expense	CA	134	134	-	-	-	-	-	-	-
9350000	MAINT GENERAL PLNT	AGEX	Administrative & General Expense	CN	36	1	11	2	3	18	2	-	-
9350000	MAINT GENERAL PLNT	AGEX	Administrative & General Expense	IDU	1	-	-	-	-	-	1	-	-
9350000	MAINT GENERAL PLNT	AGEX	Administrative & General Expense	OR	283	-	283	-	-	-	-	-	-
9350000	MAINT GENERAL PLNT	AGEX	Administrative & General Expense	SO	29,500	774	8,091	2,158	3,752	13,117	1,608	0	-
9350000	MAINT GENERAL PLNT	AGEX	Administrative & General Expense	UT	73	-	-	-	-	73	-	-	-
9350000	MAINT GENERAL PLNT	AGEX	Administrative & General Expense	WA	159	-	-	159	-	-	-	-	-
9350000	MAINT GENERAL PLNT	AGEX	Administrative & General Expense	WYP	8	-	-	-	8	-	-	-	-
9350000	MAINT GENERAL PLNT	AGEX	Administrative & General Expense	WYU	1	-	-	-	1	-	-	-	-
9350000 Total					**30,195**	**909**	**8,385**	**2,320**	**3,764**	**13,208**	**1,611**	**0**	**-**
9359500	MAINT GEN PLT-ENV AM	AGEX	Administrative & General Expense	SO	77	2	21	6	10	34	4	0	-
9359500 Total					**77**	**2**	**21**	**6**	**10**	**34**	**4**	**0**	**-**
Grand Total					**3,837,153**	**89,476**	**1,161,277**	**304,219**	**560,652**	**1,861,332**	**237,002**	**0**	**(376,806)**

B3. DEPRECIATON EXPENSE

PACIFICORP

Depreciation Expense (Actuals)
Sum of Range: 07/2022 - 06/2023
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
4030000	DEPN EXPENSE-ELECT	3102000	LAND RIGHTS	SG	711	10	191	53	98	319	40	0	0
4030000	DEPN EXPENSE-ELECT	3110000	STRUCTURES AND IMPROVEMENTS	SG	43,585	600	11,717	3,264	6,004	19,561	2,438	0	0
4030000	DEPN EXPENSE-ELECT	3120000	BOILER PLANT EQUIPMENT	SG	237,176	3,266	63,763	17,760	32,674	106,446	13,268	0	0
4030000	DEPN EXPENSE-ELECT	3140000	TURBOGENERATOR UNITS	SG	49,534	682	13,317	3,709	6,824	22,231	2,771	0	0
4030000	DEPN EXPENSE-ELECT	3150000	ACCESSORY ELECTRIC EQUIPMENT	SG	18,056	249	4,854	1,352	2,487	8,103	1,010	0	0
4030000	DEPN EXPENSE-ELECT	3157000	ACCESSORY ELECTRIC EQUIP-SUPV & ALARM	SG	2	0	0	0	0	1	0	0	0
4030000	DEPN EXPENSE-ELECT	3160000	MISCELLANEOUS POWER PLANT EQUIPMENT	SG	1,685	23	453	126	232	756	94	0	0
4030000	DEPN EXPENSE-ELECT	3302000	LAND RIGHTS	SG-P	85	1	23	6	12	38	5	0	0
4030000	DEPN EXPENSE-ELECT	3302000	LAND RIGHTS	SG-U	40	1	11	3	6	18	2	0	0
4030000	DEPN EXPENSE-ELECT	3303000	WATER RIGHTS	SG-P	0	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	0
4030000	DEPN EXPENSE-ELECT	3304000	FLOOD RIGHTS	SG-P	4	0	1	0	1	2	0	0	0
4030000	DEPN EXPENSE-ELECT	3304000	FLOOD RIGHTS	SG-U	3	0	1	0	0	1	0	0	0
4030000	DEPN EXPENSE-ELECT	3305000	LAND RIGHTS - FISH/WILDLIFE	SG-P	2	0	1	0	0	1	0	0	0
4030000	DEPN EXPENSE-ELECT	3310000	STRUCTURES AND IMPROVE	SG-P	38	1	10	3	5	17	2	0	0
4030000	DEPN EXPENSE-ELECT	3310000	STRUCTURES AND IMPROVE	SG-U	314	4	85	24	43	141	18	0	0
4030000	DEPN EXPENSE-ELECT	3311000	STRUCTURES AND IMPROVE-PRODUCTION	SG-P	2,622	36	705	196	361	1,177	147	0	0
4030000	DEPN EXPENSE-ELECT	3311000	STRUCTURES AND IMPROVE-PRODUCTION	SG-U	419	6	113	31	58	188	23	0	0
4030000	DEPN EXPENSE-ELECT	3312000	STRUCTURES AND IMPROVE-FISH/WILDLIFE	SG-P	1,243	17	334	93	171	558	70	0	0
4030000	DEPN EXPENSE-ELECT	3312000	STRUCTURES AND IMPROVE-FISH/WILDLIFE	SG-U	32	0	9	2	4	14	2	0	0
4030000	DEPN EXPENSE-ELECT	3313000	STRUCTURES AND IMPROVE-RECREATION	SG-P	327	5	88	24	45	147	18	0	0
4030000	DEPN EXPENSE-ELECT	3313000	STRUCTURES AND IMPROVE-RECREATION	SG-U	17	0	5	1	2	8	1	0	0
4030000	DEPN EXPENSE-ELECT	3320000	"RESERVOIRS, DAMS & WATERWAYS"	SG-P	144	2	39	11	20	65	8	0	0
4030000	DEPN EXPENSE-ELECT	3320000	"RESERVOIRS, DAMS & WATERWAYS"	SG-U	1,143	16	307	86	157	513	64	0	0
4030000	DEPN EXPENSE-ELECT	3321000	"RESERVOIRS, DAMS, & WTRWYS-PRODUCTION"	SG-P	9,086	125	2,443	680	1,252	4,078	508	0	0
4030000	DEPN EXPENSE-ELECT	3321000	"RESERVOIRS, DAMS, & WTRWYS-PRODUCTION"	SG-U	4,131	57	1,111	309	569	1,854	231	0	0
4030000	DEPN EXPENSE-ELECT	3322000	"RESERVOIRS, DAMS, & WTRWYS-FISH/WILDLIF	SG-P	(2,918)	(40)	(784)	(219)	(402)	(1,310)	(163)	(0)	0
4030000	DEPN EXPENSE-ELECT	3322000	"RESERVOIRS, DAMS, & WTRWYS-FISH/WILDLIF	SG-U	17	0	5	1	2	8	1	0	0
4030000	DEPN EXPENSE-ELECT	3323000	"RESERVOIRS, DAMS, & WTRWYS-RECREATION"	SG-P	4	0	1	0	0	2	0	0	0
4030000	DEPN EXPENSE-ELECT	3323000	"RESERVOIRS, DAMS, & WTRWYS-RECREATION"	SG-U	1	0	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3330000	"WATER WHEELS, TURB & GENERATORS"	SG-P	5,127	71	1,378	384	706	2,301	287	0	0
4030000	DEPN EXPENSE-ELECT	3330000	"WATER WHEELS, TURB & GENERATORS"	SG-U	1,965	27	528	147	271	882	110	0	0
4030000	DEPN EXPENSE-ELECT	3340000	ACCESSORY ELECTRIC EQUIPMENT	SG-P	5,797	80	1,559	434	799	2,602	324	0	0
4030000	DEPN EXPENSE-ELECT	3340000	ACCESSORY ELECTRIC EQUIPMENT	SG-U	593	8	160	44	82	266	33	0	0
4030000	DEPN EXPENSE-ELECT	3347000	ACCESSORY ELECT EQUIP - SUPV & ALARM	SG-P	461	6	124	35	63	207	26	0	0
4030000	DEPN EXPENSE-ELECT	3347000	ACCESSORY ELECT EQUIP - SUPV & ALARM	SG-U	5	0	1	0	1	2	0	0	0
4030000	DEPN EXPENSE-ELECT	3350000	MISC POWER PLANT EQUIP	SG-U	5	0	1	0	1	2	0	0	0
4030000	DEPN EXPENSE-ELECT	3351000	MISC POWER PLANT EQUIP - PRODUCTION	SG-P	64	1	17	5	9	29	4	0	0
4030000	DEPN EXPENSE-ELECT	3360000	"ROADS, RAILROADS & BRIDGES"	SG-P	677	9	182	51	93	304	38	0	0
4030000	DEPN EXPENSE-ELECT	3360000	"ROADS, RAILROADS & BRIDGES"	SG-U	154	2	41	12	21	69	9	0	0
4030000	DEPN EXPENSE-ELECT	3402000	LAND RIGHTS	SG	182	3	49	14	25	82	10	0	0
4030000	DEPN EXPENSE-ELECT	3410000	STRUCTURES & IMPROVEMENTS	OR	0	0	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3410000	STRUCTURES & IMPROVEMENTS	SG	7,644	105	2,055	572	1,053	3,431	428	0	0
4030000	DEPN EXPENSE-ELECT	3410000	STRUCTURES & IMPROVEMENTS	UT	3	0	0	0	0	3	0	0	0
4030000	DEPN EXPENSE-ELECT	3420000	"FUEL HOLDERS,PRODUCERS, ACCES"	SG	540	7	145	40	74	243	30	0	0
4030000	DEPN EXPENSE-ELECT	3430000	PRIME MOVERS	SG	170,590	2,349	45,862	12,774	23,501	76,561	9,543	0	0
4030000	DEPN EXPENSE-ELECT	3440000	GENERATORS	SG	22,466	309	6,040	1,682	3,095	10,083	1,257	0	0
4030000	DEPN EXPENSE-ELECT	3440000	GENERATORS	UT	13	0	0	0	0	13	0	0	0
4030000	DEPN EXPENSE-ELECT	3450000	ACCESSORY ELECTRIC EQUIPMENT	SG	13,876	191	3,730	1,039	1,912	6,228	776	0	0
4030000	DEPN EXPENSE-ELECT	3450000	ACCESSORY ELECTRIC EQUIPMENT	UT	4	0	0	0	0	4	0	0	0
4030000	DEPN EXPENSE-ELECT	3460000	MISCELLANEOUS PWR PLANT EQUIP	SG	756	10	203	57	104	339	42	0	0
4030000	DEPN EXPENSE-ELECT	3502000	LAND RIGHTS	SG	2,983	41	802	223	411	1,339	167	0	0
4030000	DEPN EXPENSE-ELECT	3520000	STRUCTURES & IMPROVEMENTS	SG	5,169	71	1,390	387	712	2,320	289	0	0
4030000	DEPN EXPENSE-ELECT	3530000	STATION EQUIPMENT	SG	44,197	609	11,882	3,310	6,089	19,836	2,472	0	0

PACIFICORP

Depreciation Expense (Actuals)
Sum of Range: 07/2022 - 06/2023
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
4030000	DEPN EXPENSE-ELECT	3534000	STATION EQUIPMENT, STEP-UP TRANSFORMERS	SG	3,213	44	864	241	443	1,442	180	0	0
4030000	DEPN EXPENSE-ELECT	3537000	STATION EQUIPMENT-SUPERVISORY & ALARM	SG	463	6	124	35	64	208	26	0	0
4030000	DEPN EXPENSE-ELECT	3540000	TOWERS AND FIXTURES	SG	21,920	302	5,893	1,641	3,020	9,838	1,226	0	0
4030000	DEPN EXPENSE-ELECT	3550000	POLES AND FIXTURES	SG	27,268	375	7,331	2,042	3,756	12,238	1,525	0	0
4030000	DEPN EXPENSE-ELECT	3560000	OVERHEAD CONDUCTORS & DEVICES	SG	30,201	416	8,119	2,261	4,160	13,554	1,689	0	0
4030000	DEPN EXPENSE-ELECT	3570000	UNDERGROUND CONDUIT	SG	60	1	16	4	8	27	3	0	0
4030000	DEPN EXPENSE-ELECT	3580000	UNDERGROUND CONDUCTORS & DEVICES	SG	146	2	39	11	20	66	8	0	0
4030000	DEPN EXPENSE-ELECT	3590000	ROADS AND TRAILS	SG	147	2	39	11	20	66	8	0	0
4030000	DEPN EXPENSE-ELECT	3602000	LAND RIGHTS	CA	13	13	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3602000	LAND RIGHTS	IDU	28	0	0	0	0	0	28	0	0
4030000	DEPN EXPENSE-ELECT	3602000	LAND RIGHTS	OR	73	0	73	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3602000	LAND RIGHTS	UT	194	0	0	0	0	194	0	0	0
4030000	DEPN EXPENSE-ELECT	3602000	LAND RIGHTS	WA	10	0	0	10	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3602000	LAND RIGHTS	WYP	86	0	0	0	86	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3602000	LAND RIGHTS	WYU	125	0	0	0	125	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3610000	STRUCTURES & IMPROVEMENTS	CA	128	128	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3610000	STRUCTURES & IMPROVEMENTS	IDU	65	0	0	0	0	0	65	0	0
4030000	DEPN EXPENSE-ELECT	3610000	STRUCTURES & IMPROVEMENTS	OR	537	0	537	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3610000	STRUCTURES & IMPROVEMENTS	UT	1,246	0	0	0	0	1,246	0	0	0
4030000	DEPN EXPENSE-ELECT	3610000	STRUCTURES & IMPROVEMENTS	WA	130	0	0	130	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3610000	STRUCTURES & IMPROVEMENTS	WYP	320	0	0	0	320	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3610000	STRUCTURES & IMPROVEMENTS	WYU	79	0	0	0	79	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3620000	STATION EQUIPMENT	CA	877	877	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3620000	STATION EQUIPMENT	IDU	935	0	0	0	0	0	935	0	0
4030000	DEPN EXPENSE-ELECT	3620000	STATION EQUIPMENT	OR	5,971	0	5,971	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3620000	STATION EQUIPMENT	UT	13,169	0	0	0	0	13,169	0	0	0
4030000	DEPN EXPENSE-ELECT	3620000	STATION EQUIPMENT	WA	1,915	0	0	1,915	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3620000	STATION EQUIPMENT	WYP	2,605	0	0	0	2,605	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3620000	STATION EQUIPMENT	WYU	372	0	0	0	372	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	CA	17	17	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	IDU	12	0	0	0	0	0	12	0	0
4030000	DEPN EXPENSE-ELECT	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	OR	97	0	97	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	UT	177	0	0	0	0	177	0	0	0
4030000	DEPN EXPENSE-ELECT	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	WA	36	0	0	36	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	WYP	41	0	0	0	41	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	WYU	6	0	0	0	6	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3640000	"POLES, TOWERS AND FIXTURES"	CA	3,486	3,486	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3640000	"POLES, TOWERS AND FIXTURES"	IDU	3,693	0	0	0	0	0	3,693	0	0
4030000	DEPN EXPENSE-ELECT	3640000	"POLES, TOWERS AND FIXTURES"	OR	15,833	0	15,833	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3640000	"POLES, TOWERS AND FIXTURES"	UT	16,941	0	0	0	0	16,941	0	0	0
4030000	DEPN EXPENSE-ELECT	3640000	"POLES, TOWERS AND FIXTURES"	WA	4,194	0	0	4,194	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3640000	"POLES, TOWERS AND FIXTURES"	WYP	5,297	0	0	0	5,297	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3640000	"POLES, TOWERS AND FIXTURES"	WYU	1,050	0	0	0	1,050	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3650000	OVERHEAD CONDUCTORS & DEVICES	CA	1,388	1,388	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3650000	OVERHEAD CONDUCTORS & DEVICES	IDU	1,064	0	0	0	0	0	1,064	0	0
4030000	DEPN EXPENSE-ELECT	3650000	OVERHEAD CONDUCTORS & DEVICES	OR	6,641	0	6,641	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3650000	OVERHEAD CONDUCTORS & DEVICES	UT	7,502	0	0	0	0	7,502	0	0	0
4030000	DEPN EXPENSE-ELECT	3650000	OVERHEAD CONDUCTORS & DEVICES	WA	2,149	0	0	2,149	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3650000	OVERHEAD CONDUCTORS & DEVICES	WYP	2,826	0	0	0	2,826	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3650000	OVERHEAD CONDUCTORS & DEVICES	WYU	369	0	0	0	369	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3660000	UNDERGROUND CONDUIT	CA	478	478	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3660000	UNDERGROUND CONDUIT	IDU	304	0	0	0	0	0	304	0	0
4030000	DEPN EXPENSE-ELECT	3660000	UNDERGROUND CONDUIT	OR	2,051	0	2,051	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3660000	UNDERGROUND CONDUIT	UT	6,180	0	0	0	0	6,180	0	0	0

PACIFICORP

Depreciation Expense (Actuals)
Sum of Range: 07/2022 - 06/2023
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
4030000	DEPN EXPENSE-ELECT	3660000	UNDERGROUND CONDUIT	WA	550	0	0	550	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3660000	UNDERGROUND CONDUIT	WYP	845	0	0	0	845	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3660000	UNDERGROUND CONDUIT	WYU	154	0	0	0	154	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3670000	UNDERGROUND CONDUCTORS & DEVICES	CA	550	550	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3670000	UNDERGROUND CONDUCTORS & DEVICES	IDU	627	0	0	0	0	0	627	0	0
4030000	DEPN EXPENSE-ELECT	3670000	UNDERGROUND CONDUCTORS & DEVICES	OR	4,542	0	4,542	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3670000	UNDERGROUND CONDUCTORS & DEVICES	UT	13,016	0	0	0	0	13,016	0	0	0
4030000	DEPN EXPENSE-ELECT	3670000	UNDERGROUND CONDUCTORS & DEVICES	WA	764	0	0	764	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3670000	UNDERGROUND CONDUCTORS & DEVICES	WYP	1,324	0	0	0	1,324	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3670000	UNDERGROUND CONDUCTORS & DEVICES	WYU	495	0	0	0	495	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3680000	LINE TRANSFORMERS	CA	1,355	1,355	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3680000	LINE TRANSFORMERS	IDU	2,040	0	0	0	0	0	2,040	0	0
4030000	DEPN EXPENSE-ELECT	3680000	LINE TRANSFORMERS	OR	12,032	0	12,032	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3680000	LINE TRANSFORMERS	UT	15,344	0	0	0	0	15,344	0	0	0
4030000	DEPN EXPENSE-ELECT	3680000	LINE TRANSFORMERS	WA	3,012	0	0	3,012	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3680000	LINE TRANSFORMERS	WYP	3,478	0	0	0	3,478	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3680000	LINE TRANSFORMERS	WYU	488	0	0	0	488	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3691000	SERVICES - OVERHEAD	CA	270	270	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3691000	SERVICES - OVERHEAD	IDU	232	0	0	0	0	0	232	0	0
4030000	DEPN EXPENSE-ELECT	3691000	SERVICES - OVERHEAD	OR	2,267	0	2,267	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3691000	SERVICES - OVERHEAD	UT	2,460	0	0	0	0	2,460	0	0	0
4030000	DEPN EXPENSE-ELECT	3691000	SERVICES - OVERHEAD	WA	596	0	0	596	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3691000	SERVICES - OVERHEAD	WYP	441	0	0	0	441	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3691000	SERVICES - OVERHEAD	WYU	99	0	0	0	99	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3692000	SERVICES - UNDERGROUND	CA	404	404	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3692000	SERVICES - UNDERGROUND	IDU	963	0	0	0	0	0	963	0	0
4030000	DEPN EXPENSE-ELECT	3692000	SERVICES - UNDERGROUND	OR	4,941	0	4,941	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3692000	SERVICES - UNDERGROUND	UT	7,172	0	0	0	0	7,172	0	0	0
4030000	DEPN EXPENSE-ELECT	3692000	SERVICES - UNDERGROUND	WA	1,245	0	0	1,245	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3692000	SERVICES - UNDERGROUND	WYP	1,195	0	0	0	1,195	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3692000	SERVICES - UNDERGROUND	WYU	407	0	0	0	407	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3700000	METERS	CA	316	316	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3700000	METERS	IDU	732	0	0	0	0	0	732	0	0
4030000	DEPN EXPENSE-ELECT	3700000	METERS	OR	1,778	0	1,778	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3700000	METERS	UT	7,069	0	0	0	0	7,069	0	0	0
4030000	DEPN EXPENSE-ELECT	3700000	METERS	WA	790	0	0	790	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3700000	METERS	WYP	771	0	0	0	771	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3700000	METERS	WYU	151	0	0	0	151	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3710000	INSTALL ON CUSTOMERS PREMISES	CA	15	15	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3710000	INSTALL ON CUSTOMERS PREMISES	IDU	8	0	0	0	0	0	8	0	0
4030000	DEPN EXPENSE-ELECT	3710000	INSTALL ON CUSTOMERS PREMISES	OR	116	0	116	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3710000	INSTALL ON CUSTOMERS PREMISES	UT	265	0	0	0	0	265	0	0	0
4030000	DEPN EXPENSE-ELECT	3710000	INSTALL ON CUSTOMERS PREMISES	WA	21	0	0	21	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3710000	INSTALL ON CUSTOMERS PREMISES	WYP	30	0	0	0	30	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3710000	INSTALL ON CUSTOMERS PREMISES	WYU	5	0	0	0	5	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3730000	STREET LIGHTING & SIGNAL SYSTEMS	CA	28	28	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3730000	STREET LIGHTING & SIGNAL SYSTEMS	IDU	35	0	0	0	0	0	35	0	0
4030000	DEPN EXPENSE-ELECT	3730000	STREET LIGHTING & SIGNAL SYSTEMS	OR	618	0	618	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3730000	STREET LIGHTING & SIGNAL SYSTEMS	UT	1,155	0	0	0	0	1,155	0	0	0
4030000	DEPN EXPENSE-ELECT	3730000	STREET LIGHTING & SIGNAL SYSTEMS	WA	117	0	0	117	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3730000	STREET LIGHTING & SIGNAL SYSTEMS	WYP	239	0	0	0	239	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3730000	STREET LIGHTING & SIGNAL SYSTEMS	WYU	62	0	0	0	62	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3892000	LAND RIGHTS	IDU	0	0	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3892000	LAND RIGHTS	OR	0	0	0	0	0	0	0	0	0

PACIFICORP

Depreciation Expense (Actuals)
Sum of Range: 07/2022 - 06/2023
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
4030000	DEPN EXPENSE-ELECT	3892000	LAND RIGHTS	SG	0	0	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3892000	LAND RIGHTS	SO	2	0	1	0	0	1	0	0	0
4030000	DEPN EXPENSE-ELECT	3892000	LAND RIGHTS	UT	2	0	0	0	0	2	0	0	0
4030000	DEPN EXPENSE-ELECT	3892000	LAND RIGHTS	WYP	1	0	0	0	1	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3892000	LAND RIGHTS	WYU	0	0	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	CA	77	77	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	CN	210	5	64	14	15	103	9	0	0
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	IDU	236	0	0	0	0	0	236	0	0
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	OR	792	0	792	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	SE	24	0	6	2	4	11	1	0	0
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	SG	278	4	75	21	38	125	16	0	0
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	SO	2,440	64	669	179	310	1,085	133	0	0
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	UT	1,218	0	0	0	0	1,218	0	0	0
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	WA	245	0	0	245	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	WYP	305	0	0	0	305	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3900000	STRUCTURES AND IMPROVEMENTS	WYU	121	0	0	0	121	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	CA	5	5	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	CN	35	1	11	2	2	17	1	0	0
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	IDU	4	0	0	0	0	0	4	0	0
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	OR	68	0	68	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	SE	0	0	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	SG	94	1	25	7	13	42	5	0	0
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	SO	727	19	199	53	92	323	40	0	0
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	UT	52	0	0	0	0	52	0	0	0
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	WA	3	0	0	3	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	WYP	26	0	0	0	26	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3910000	OFFICE FURNITURE	WYU	2	0	0	0	2	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	CA	10	10	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	CN	476	11	146	32	34	233	20	0	0
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	IDU	84	0	0	0	0	0	84	0	0
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	OR	193	0	193	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	SE	5	0	1	0	1	2	0	0	0
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	SG	546	8	147	41	75	245	31	0	0
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	SO	12,443	326	3,413	910	1,582	5,533	678	0	0
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	UT	162	0	0	0	0	162	0	0	0
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	WA	66	0	0	66	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	WYP	276	0	0	0	276	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	WYU	15	0	0	0	15	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3913000	OFFICE EQUIPMENT	CN	0	0	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3913000	OFFICE EQUIPMENT	OR	0	0	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3913000	OFFICE EQUIPMENT	SG	5	0	1	0	1	2	0	0	0
4030000	DEPN EXPENSE-ELECT	3913000	OFFICE EQUIPMENT	SO	92	2	25	7	12	41	5	0	0
4030000	DEPN EXPENSE-ELECT	3913000	OFFICE EQUIPMENT	UT	1	0	0	0	0	1	0	0	0
4030000	DEPN EXPENSE-ELECT	3913000	OFFICE EQUIPMENT	WYU	1	0	0	0	1	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3930000	STORES EQUIPMENT	CA	4	4	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3930000	STORES EQUIPMENT	IDU	28	0	0	0	0	0	28	0	0
4030000	DEPN EXPENSE-ELECT	3930000	STORES EQUIPMENT	OR	120	0	120	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3930000	STORES EQUIPMENT	SG	273	4	73	20	38	122	15	0	0
4030000	DEPN EXPENSE-ELECT	3930000	STORES EQUIPMENT	SO	9	0	3	1	1	4	1	0	0
4030000	DEPN EXPENSE-ELECT	3930000	STORES EQUIPMENT	UT	164	0	0	0	0	164	0	0	0
4030000	DEPN EXPENSE-ELECT	3930000	STORES EQUIPMENT	WA	29	0	0	29	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3930000	STORES EQUIPMENT	WYP	56	0	0	0	56	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3930000	STORES EQUIPMENT	WYU	0	0	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3940000	"TLS, SHOP, GAR EQUIPMENT"	CA	48	48	0	0	0	0	0	0	0

PACIFICORP

Depreciation Expense (Actuals)
Sum of Range: 07/2022 - 06/2023
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
4030000	DEPN EXPENSE-ELECT	3940000	"TLS, SHOP, GAR EQUIPMENT"	IDU	95	0	0	0	0	0	95	0	0
4030000	DEPN EXPENSE-ELECT	3940000	"TLS, SHOP, GAR EQUIPMENT"	OR	459	0	459	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3940000	"TLS, SHOP, GAR EQUIPMENT"	SE	4	0	1	0	1	2	0	0	0
4030000	DEPN EXPENSE-ELECT	3940000	"TLS, SHOP, GAR EQUIPMENT"	SG	921	13	248	69	127	413	52	0	0
4030000	DEPN EXPENSE-ELECT	3940000	"TLS, SHOP, GAR EQUIPMENT"	SO	75	2	21	6	10	33	4	0	0
4030000	DEPN EXPENSE-ELECT	3940000	"TLS, SHOP, GAR EQUIPMENT"	UT	694	0	0	0	0	694	0	0	0
4030000	DEPN EXPENSE-ELECT	3940000	"TLS, SHOP, GAR EQUIPMENT"	WA	125	0	0	125	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3940000	"TLS, SHOP, GAR EQUIPMENT"	WYP	170	0	0	0	170	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3940000	"TLS, SHOP, GAR EQUIPMENT"	WYU	12	0	0	0	12	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3950000	LABORATORY EQUIPMENT	CA	34	34	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3950000	LABORATORY EQUIPMENT	IDU	74	0	0	0	0	0	74	0	0
4030000	DEPN EXPENSE-ELECT	3950000	LABORATORY EQUIPMENT	OR	531	0	531	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3950000	LABORATORY EQUIPMENT	SE	60	1	16	4	9	27	4	0	0
4030000	DEPN EXPENSE-ELECT	3950000	LABORATORY EQUIPMENT	SG	370	5	99	28	51	166	21	0	0
4030000	DEPN EXPENSE-ELECT	3950000	LABORATORY EQUIPMENT	SO	258	7	71	19	33	115	14	0	0
4030000	DEPN EXPENSE-ELECT	3950000	LABORATORY EQUIPMENT	UT	485	0	0	0	0	485	0	0	0
4030000	DEPN EXPENSE-ELECT	3950000	LABORATORY EQUIPMENT	WA	74	0	0	74	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3950000	LABORATORY EQUIPMENT	WYP	167	0	0	0	167	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3950000	LABORATORY EQUIPMENT	WYU	6	0	0	0	6	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	CA	237	237	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	CN	149	3	46	10	11	73	6	0	0
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	IDU	608	0	0	0	0	0	608	0	0
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	OR	2,651	0	2,651	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	SE	12	0	3	1	2	5	1	0	0
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	SG	8,608	119	2,314	645	1,186	3,863	482	0	0
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	SO	4,160	109	1,141	304	529	1,850	227	0	0
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	UT	3,109	0	0	0	0	3,109	0	0	0
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	WA	536	0	0	536	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	WYP	1,149	0	0	0	1,149	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3970000	COMMUNICATION EQUIPMENT	WYU	279	0	0	0	279	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3972000	MOBILE RADIO EQUIPMENT	CA	31	31	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3972000	MOBILE RADIO EQUIPMENT	IDU	24	0	0	0	0	0	24	0	0
4030000	DEPN EXPENSE-ELECT	3972000	MOBILE RADIO EQUIPMENT	OR	173	0	173	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3972000	MOBILE RADIO EQUIPMENT	SE	7	0	2	1	1	3	0	0	0
4030000	DEPN EXPENSE-ELECT	3972000	MOBILE RADIO EQUIPMENT	SG	336	5	90	25	46	151	19	0	0
4030000	DEPN EXPENSE-ELECT	3972000	MOBILE RADIO EQUIPMENT	SO	15	0	4	1	2	7	1	0	0
4030000	DEPN EXPENSE-ELECT	3972000	MOBILE RADIO EQUIPMENT	UT	150	0	0	0	0	150	0	0	0
4030000	DEPN EXPENSE-ELECT	3972000	MOBILE RADIO EQUIPMENT	WA	27	0	0	27	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3972000	MOBILE RADIO EQUIPMENT	WYP	42	0	0	0	42	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3972000	MOBILE RADIO EQUIPMENT	WYU	9	0	0	0	9	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	CA	3	3	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	CN	4	0	1	0	0	2	0	0	0
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	IDU	4	0	0	0	0	0	4	0	0
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	OR	67	0	67	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	SE	0	0	0	0	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	SG	152	2	41	11	21	68	8	0	0
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	SO	92	2	25	7	12	41	5	0	0
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	UT	82	0	0	0	0	82	0	0	0
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	WA	10	0	0	10	0	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	WYP	13	0	0	0	13	0	0	0	0
4030000	DEPN EXPENSE-ELECT	3980000	MISCELLANEOUS EQUIPMENT	WYU	1	0	0	0	1	0	0	0	0
4030000 Total					**991,960**	**20,596**	**268,911**	**74,039**	**131,411**	**442,238**	**54,764**	**0**	**0**
4032000	DEPR - STEAM	565131	DEPR - PROD STEAM NOT CLASSIFIED	SG	1,683	23	453	126	232	756	94	0	0
4032000	DEPR - STEAM	565247	Depr - Prod Steam UT STEP	OTHER	(6,749)	0	0	0	0	0	0	0	(6,749)

Depreciation Expense (Actuals)
Sum of Range: 07/2022 - 06/2023
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
4032000 Total					**(5,066)**	**23**	**453**	**126**	**232**	**756**	**94**	**0**	**(6,749)**
4033000	DEPR - HYDRO	565133	DEPR - PROD HYDRO NOT CLASSIFIED	SG-P	(578)	(8)	(155)	(43)	(80)	(259)	(32)	(0)	0
4033000	DEPR - HYDRO	565133	DEPR - PROD HYDRO NOT CLASSIFIED	SG-U	329	5	89	25	45	148	18	0	0
4033000 Total					**(249)**	**(3)**	**(67)**	**(19)**	**(34)**	**(112)**	**(14)**	**(0)**	**0**
4034000	DEPR - OTHER	565134	DEPR - PROD OTHER NOT CLASSIFIED	SG	379	5	102	28	52	170	21	0	-
4034000 Total					**379**	**5**	**102**	**28**	**52**	**170**	**21**	**0**	**0**
4035000	DEPR-TRANSMISSION	565141	DEPR - TRANS ASSETS NOT CLASSIFIED	SG	2,491	34	670	186	343	1,118	139	0	-
4035000 Total					**2,491**	**34**	**670**	**186**	**343**	**1,118**	**139**	**0**	**0**
4036000	DEPR-DISTRIBUTION	565161	DEPR - DIST ASSETS NOT CLASSIFIED	CA	324	324	0	0	0	0	0	0	0
4036000	DEPR-DISTRIBUTION	565161	DEPR - DIST ASSETS NOT CLASSIFIED	IDU	93	0	0	0	0	0	93	0	0
4036000	DEPR-DISTRIBUTION	565161	DEPR - DIST ASSETS NOT CLASSIFIED	OR	551	0	551	0	0	0	0	0	0
4036000	DEPR-DISTRIBUTION	565161	DEPR - DIST ASSETS NOT CLASSIFIED	UT	694	0	0	0	0	694	0	0	0
4036000	DEPR-DISTRIBUTION	565161	DEPR - DIST ASSETS NOT CLASSIFIED	WA	311	0	0	311	0	0	0	0	0
4036000	DEPR-DISTRIBUTION	565161	DEPR - DIST ASSETS NOT CLASSIFIED	WYP	147	0	0	0	147	0	0	0	0
4036000 Total					**2,119**	**324**	**551**	**311**	**147**	**694**	**93**	**0**	**0**
4037000	DEPR - GENERAL	565201	DEPR - GEN ASSETS NOT CLASSIFIED	SG	2,079	29	559	156	286	933	116	0	-
4037000 Total					**2,079**	**29**	**559**	**156**	**286**	**933**	**116**	**0**	**0**
4039999	DEPR EXP-ELEC, OTH	565970	DEPRECIATION-JOINT OWNER BILLED-CREDIT	SG	(262)	(4)	(70)	(20)	(36)	(117)	(15)	(0)	-
4039999 Total					**(262)**	**(4)**	**(70)**	**(20)**	**(36)**	**(117)**	**(15)**	**(0)**	**0**
Grand Total					**993,452**	**21,004**	**271,108**	**74,808**	**132,401**	**445,680**	**55,200**	**0**	**(6,749)**

B4. AMORTIZATION EXPENSE

Amortization Expense (Actuals)
Sum of Range: 07/2022 - 06/2023
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
4040000	AMOR LTD TRM PLNT	3020000	FRANCHISES AND CONSENTS	IDU	13	-	-	-	-	-	13	-	-
4040000	AMOR LTD TRM PLNT	3020000	FRANCHISES AND CONSENTS	SG	638	9	171	48	88	286	36	0	-
4040000	AMOR LTD TRM PLNT	3020000	FRANCHISES AND CONSENTS	SG-P	2,682	37	721	201	370	1,204	150	0	-
4040000	AMOR LTD TRM PLNT	3020000	FRANCHISES AND CONSENTS	SG-U	336	5	90	25	46	151	19	0	-
4040000	AMOR LTD TRM PLNT	3031040	INTANGIBLE PLANT	OR	9	-	9	-	-	-	-	-	-
4040000	AMOR LTD TRM PLNT	3031040	INTANGIBLE PLANT	SG	1,041	14	280	78	143	467	58	0	-
4040000	AMOR LTD TRM PLNT	3031040	INTANGIBLE PLANT	UT	79	-	-	-	-	79	-	-	-
4040000	AMOR LTD TRM PLNT	3031040	INTANGIBLE PLANT	WYP	59	-	-	-	59	-	-	-	-
4040000	AMOR LTD TRM PLNT	3031050	RWT - RCMS WORK TRACKING	SO	89	2	24	6	11	39	5	0	-
4040000	AMOR LTD TRM PLNT	3031680	CADOPS - COMPUTER-ASSISTED DISTRIBUTION	SO	925	24	254	68	118	411	50	0	-
4040000	AMOR LTD TRM PLNT	3031830	CUSTOMER SERVICE SYSTEM	CN	6,789	154	2,085	454	482	3,326	288	-	-
4040000	AMOR LTD TRM PLNT	3032040	SAP	SO	5,395	142	1,480	395	686	2,399	294	0	-
4040000	AMOR LTD TRM PLNT	3032130	NODAL PRICING SOFTWARE	SG	664	9	178	50	91	298	37	0	-
4040000	AMOR LTD TRM PLNT	3032140	ESM-IRP	SO	776	20	213	57	99	345	42	0	-
4040000	AMOR LTD TRM PLNT	3032150	CELONIS	SO	845	22	232	62	107	376	46	0	-
4040000	AMOR LTD TRM PLNT	3032160	ARCOS	SO	623	16	171	46	79	277	34	0	-
4040000	AMOR LTD TRM PLNT	3032170	AZURE B2C - IDENTITY MGT	SO	286	7	78	21	36	127	16	0	-
4040000	AMOR LTD TRM PLNT	3032180	IAM - SCHEDULING/TAGGING SYSTEM	SO	273	7	75	20	35	121	15	0	-
4040000	AMOR LTD TRM PLNT	3032190	4040000/3032190	SO	168	4	46	12	21	75	9	0	-
4040000	AMOR LTD TRM PLNT	3032200	ITOA	SO	874	23	240	64	111	389	48	0	-
4040000	AMOR LTD TRM PLNT	3032210	FACILITY INSPECTION REPORTING SYS	SO	325	9	89	24	41	144	18	0	-
4040000	AMOR LTD TRM PLNT	3032450	MID OFFICE IMPROVEMENT PROJECT	SO	4	0	1	0	1	2	0	0	-
4040000	AMOR LTD TRM PLNT	3032530	POLE ATTACHMENT MGMT SYSTEM	SO	6	0	2	0	1	3	0	0	-
4040000	AMOR LTD TRM PLNT	3032600	SINGLE PERSON SCHEDULING	SO	184	5	51	13	23	82	10	0	-
4040000	AMOR LTD TRM PLNT	3032640	TIBCO SOFTWARE	SO	507	13	139	37	64	225	28	0	-
4040000	AMOR LTD TRM PLNT	3032690	UTILITY INTERNATIONAL FORECASTING MODEL	SO	1,657	43	454	121	211	737	90	0	-
4040000	AMOR LTD TRM PLNT	3032710	ROUGE RIVER HYDRO INTANGIBLES	SG	7	0	2	0	1	3	0	0	-
4040000	AMOR LTD TRM PLNT	3032740	GADSBY INTANGIBLE ASSETS	SG	4	0	1	0	0	2	0	0	-
4040000	AMOR LTD TRM PLNT	3032760	SWIFT 2 IMPROVEMENTS	SG	432	6	116	32	59	194	24	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	2	0	1	0	0	1	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	6	0	2	0	1	2	0	0	-
4040000	AMOR LTD TRM PLNT	3032860	WEB SOFTWARE	SO	1,870	49	513	137	238	831	102	0	-
4040000	AMOR LTD TRM PLNT	3032900	IDAHO TRANSMISSION CUSTOMER-OWNED ASSETS	SG	360	5	97	27	50	162	20	0	-
4040000	AMOR LTD TRM PLNT	3032990	P8DM - FILENET P8 DOCUMENT MANAGEMENT (E	SO	483	13	132	35	61	215	26	0	-
4040000	AMOR LTD TRM PLNT	3033090	STEAM PLANT INTANGIBLE ASSETS	SG	2,406	33	647	180	331	1,080	135	0	-
4040000	AMOR LTD TRM PLNT	3033220	MONARCH EMS/SCADA	SO	4,314	113	1,183	316	549	1,918	235	0	-
4040000	AMOR LTD TRM PLNT	3033240	IEE - Itron Enterprise Addition	CN	487	11	149	33	35	238	21	-	-
4040000	AMOR LTD TRM PLNT	3033250	AMI Metering Software	CN	5,229	118	1,606	350	371	2,562	222	-	-
4040000	AMOR LTD TRM PLNT	3033260	Big Data & Analytics	SO	1,895	50	520	139	241	843	103	0	-
4040000	AMOR LTD TRM PLNT	3033270	CES - Customer Experience System	CN	2,129	48	654	142	151	1,043	90	-	-
4040000	AMOR LTD TRM PLNT	3033280	MAPAPPS - Mapping Systems Application	SO	1,803	47	495	132	229	802	98	0	-
4040000	AMOR LTD TRM PLNT	3033290	CUSTOMER CONTACTS	CN	781	18	240	52	55	383	33	-	-
4040000	AMOR LTD TRM PLNT	3033310	C&T - ENERGY TRADING SYSTEM	SO	331	9	91	24	42	147	18	0	-
4040000	AMOR LTD TRM PLNT	3033320	CAS - CONTROL AREA SCHEDULING (TRANSM)	SO	57	1	16	4	7	25	3	0	-
4040000	AMOR LTD TRM PLNT	3033370	DISTRIBUTION INTANGIBLES	WYP	117	-	-	-	117	-	-	-	-
4040000	AMOR LTD TRM PLNT	3033410	M365	SO	742	19	204	54	94	330	40	0	-
4040000	AMOR LTD TRM PLNT	3033420	SUBSTATION RELIABILITY SOFTWARE	SO	195	5	53	14	25	87	11	0	-
4040000	AMOR LTD TRM PLNT	3033430	DEPLOY DISTRIBUTION MGMT SYSTEM	SO	361	9	99	26	46	160	20	0	-
4040000	AMOR LTD TRM PLNT	3033440	DISTRIBUTION ENGINEERING COSTS	SO	204	5	56	15	26	91	11	0	-
4040000	AMOR LTD TRM PLNT	3033450	MAXIMO	SO	1,809	47	496	132	230	804	99	0	-
4040000	AMOR LTD TRM PLNT	3033460	AURORA	SO	333	9	91	24	42	148	18	0	-
4040000	AMOR LTD TRM PLNT	3033470	AUGMENTED REALITY	SO	362	9	99	26	46	161	20	0	-
4040000	AMOR LTD TRM PLNT	3033480	CXP	CN	271	6	83	18	19	133	12	-	-
4040000	AMOR LTD TRM PLNT	3033490	VMWARE	SO	669	18	184	49	85	298	37	0	-
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	CA	1	1	-	-	-	-	-	-	-
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	IDU	1	-	-	-	-	-	1	-	-
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	OR	2	-	2	-	-	-	-	-	-

PACIFICORP

Amortization Expense (Actuals)
Sum of Range: 07/2022 - 06/2023
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
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	8,029	111	2,159	601	1,106	3,603	449	0	-
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	SO	464	12	127	34	59	206	25	0	-
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	UT	1	-	-	-	-	1	-	-	-
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	WA	2	-	-	2	-	-	-	-	-
4040000	AMOR LTD TRM PLNT	3034900	MISC - MISCELLANEOUS	WYP	45	-	-	-	45	-	-	-	-
4040000	AMOR LTD TRM PLNT	3035320	HYDRO PLANT INTANGIBLES	SG	194	3	52	14	27	87	11	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	3035330	OATI-OASIS INTERFACE	SO	69	2	19	5	9	31	4	0	-
4040000	AMOR LTD TRM PLNT	3316000	STRUCTURES - LEASE IMPROVEMENTS	SG-P	314	4	84	23	43	141	18	0	-
4040000	AMOR LTD TRM PLNT	3456000	Electric Equipment - Leasehold Improveme	OR	60	-	60	-	-	-	-	-	-
4040000	AMOR LTD TRM PLNT	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	OR	145	-	145	-	-	-	-	-	-
4040000	AMOR LTD TRM PLNT	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	SO	160	4	44	12	20	71	9	0	-
4040000	AMOR LTD TRM PLNT	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	WA	97	-	-	97	-	-	-	-	-
4040000	AMOR LTD TRM PLNT	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	WYP	142	-	-	-	142	-	-	-	-
4040000 Total					**62,672**	**1,355**	**17,614**	**4,559**	**7,535**	**28,385**	**3,225**	**0**	**0**
4049000	AMR LTD TRM PLNT-OTH	566201	Amort Exp - Hydro - UT Klamath Adj	OTHER	2,105	-	-	-	-	-	-	-	2,105
4049000	AMR LTD TRM PLNT-OTH	566205	Amort Exp - Non-Rec	SG	(49)	(1)	(13)	(4)	(7)	(22)	(3)	(0)	-
4049000	AMR LTD TRM PLNT-OTH	566970	AMORTIZATION JO BILL CREDIT	SG	(460)	(6)	(124)	(34)	(63)	(207)	(26)	(0)	-
4049000 Total					**1,596**	**(7)**	**(137)**	**(38)**	**(70)**	**(228)**	**(28)**	**(0)**	**2,105**
4061000	EL PLNT ACQ ADJ-CM	566920	AMORT ELEC PLANT ACQ ADJ	SG	75	1	20	6	10	34	4	0	-
4061000	EL PLNT ACQ ADJ-CM	566920	AMORT ELEC PLANT ACQ ADJ	UT	302	-	-	-	-	302	-	-	-
4061000 Total					**377**	**1**	**20**	**6**	**10**	**335**	**4**	**0**	**0**
4073000	REGULATORY DEBITS	566940	AMORT OF REG ASSETS - DEBITS	SG	657	9	177	49	91	295	37	0	-
4073000	REGULATORY DEBITS	566982	Amortz Reg A-Unrcvrd Plt/Decom Csts-ID	IDU	66	-	-	-	-	-	66	-	-
4073000	REGULATORY DEBITS	566983	Amortz Reg A-Unrcvrd Plt/Decom Csts-OR	OR	(1,689)	-	(1,689)	-	-	-	-	-	-
4073000	REGULATORY DEBITS	566984	Amortz Reg A-Unrcvrd Plt/Decom Csts-UT	UT	2,758	-	-	-	-	2,758	-	-	-
4073000	REGULATORY DEBITS	566986	Amortz Reg A-Unrcvrd Plt/Decom Csts-WY	WYP	4,747	-	-	-	4,747	-	-	-	-
4073000	REGULATORY DEBITS	566992	OR Meters Replaced by AMI Amortization	OTHER	5,025	-	-	-	-	-	-	-	5,025
4073000	REGULATORY DEBITS	586902	Preferred Stock Repurchase Loss Amort	OTHER	124	-	-	-	-	-	-	-	124
4073000 Total					**11,688**	**9**	**(1,512)**	**49**	**4,838**	**3,053**	**103**	**0**	**5,149**
4074100	Reg Credits-BPA Exch	301101	BPA Reg Bill Bal Acct - Residential	IDU	7,594	-	-	-	-	-	7,594	-	-
4074100	Reg Credits-BPA Exch	301101	BPA Reg Bill Bal Acct - Residential	OR	56,685	-	56,685	-	-	-	-	-	-
4074100	Reg Credits-BPA Exch	301101	BPA Reg Bill Bal Acct - Residential	WA	16,161	-	-	16,161	-	-	-	-	-
4074100	Reg Credits-BPA Exch	301201	BPA Reg Bill Bal Acct - Commercial	IDU	436	-	-	-	-	-	436	-	-
4074100	Reg Credits-BPA Exch	301201	BPA Reg Bill Bal Acct - Commercial	OR	1,385	-	1,385	-	-	-	-	-	-
4074100	Reg Credits-BPA Exch	301201	BPA Reg Bill Bal Acct - Commercial	WA	630	-	-	630	-	-	-	-	-
4074100	Reg Credits-BPA Exch	301301	BPA Reg Bill Bal Acct - Industrial	IDU	36	-	-	-	-	-	36	-	-
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	17	-	-	17	-	-	-	-	-
4074100	Reg Credits-BPA Exch	301451	BPA Reg Bill Bal Acct - Irrigation	IDU	2,121	-	-	-	-	-	2,121	-	-
4074100	Reg Credits-BPA Exch	301451	BPA Reg Bill Bal Acct - Irrigation	OR	845	-	845	-	-	-	-	-	-
4074100	Reg Credits-BPA Exch	301451	BPA Reg Bill Bal Acct - Irrigation	WA	712	-	-	712	-	-	-	-	-
4074100	Reg Credits-BPA Exch	301601	BPA Reg Bill Bal Acct - St/Hwy Lighting	OR	0	-	0	-	-	-	-	-	-
4074100 Total					**86,624**	**0**	**58,916**	**17,520**	**0**	**0**	**10,187**	**0**	**0**
4074200	Reg Credits-BPA Exch	505201	Regional Bill Intchg Rec/Del-OR (PP)	OR	(58,916)	-	(58,916)	-	-	-	-	-	-
4074200	Reg Credits-BPA Exch	505202	Regional Bill Intchg Rec/Del-WA (PP)	WA	(17,520)	-	-	(17,520)	-	-	-	-	-
4074200	Reg Credits-BPA Exch	505204	Regional Bill Intchg Rec/Del-ID (RMP)	IDU	(10,187)	-	-	-	-	-	(10,187)	-	-
4074200 Total					**(86,624)**	**0**	**(58,916)**	**(17,520)**	**0**	**0**	**(10,187)**	**0**	**0**
Grand Total					**76,333**	**1,358**	**15,985**	**4,576**	**12,313**	**31,545**	**3,303**	**0**	**7,254**

B5. TAXES OTHER THAN INCOME

PACIFICORP

Taxes Other Than Income (Actuals)
Sum of Range: 07/2022 - 06/2023
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
4081000	TAX OTH INC-U OP I	583400	4081000/583400	SO	(3)	(0)	(1)	(0)	(0)	(1)	(0)	(0)	-
4081000	TAX OTH INC-U OP I	584960	Taxes Other Non-Income - Credit	SO	(498)	(13)	(136)	(36)	(63)	(221)	(27)	(0)	-
4081000 Total					**(500)**	**(13)**	**(137)**	**(37)**	**(64)**	**(223)**	**(27)**	**(0)**	**-**
4081500	PROPERTY TAXES	579000	PROPERTY TAX	GPS	133,793	3,510	36,693	9,789	17,015	59,491	7,295	0	-
4081500	PROPERTY TAXES	579012	Property Tax Exp - Reg Deferral/Amortz	OR	45	-	45	-	-	-	-	-	-
4081500 Total					**133,838**	**3,510**	**36,738**	**9,789**	**17,015**	**59,491**	**7,295**	**0**	**-**
4081800	FRANCHISE TAXES	578000	FRANCHISE & OCCUPATION TAXES	CA	1,370	1,370	-	-	-	-	-	-	-
4081800	FRANCHISE TAXES	578000	FRANCHISE & OCCUPATION TAXES	OR	31,304	-	31,304	-	-	-	-	-	-
4081800	FRANCHISE TAXES	578000	FRANCHISE & OCCUPATION TAXES	UT	8	-	-	-	-	8	-	-	-
4081800	FRANCHISE TAXES	578000	FRANCHISE & OCCUPATION TAXES	WA	0	-	-	0	-	-	-	-	-
4081800	FRANCHISE TAXES	578000	FRANCHISE & OCCUPATION TAXES	WYP	1,938	-	-	-	1,938	-	-	-	-
4081800 Total					**34,622**	**1,370**	**31,304**	**0**	**1,938**	**8**	**-**	**-**	**-**
4081990	MISC TAXES - OTHER	583260	PUBLIC UTILITY TAX	SO	15,922	418	4,367	1,165	2,025	7,080	868	0	-
4081990	MISC TAXES - OTHER	583261	OREGON ENERGY RESOURCE SUPPLIER TAX	OR	1,514	-	1,514	-	-	-	-	-	-
4081990	MISC TAXES - OTHER	583263	MONTANA ENERGY TAX	SE	379	5	100	26	56	169	23	0	-
4081990	MISC TAXES - OTHER	583265	WASHINGTON GROSS REVENUE TAX - SERVICES	WA	27	-	-	27	-	-	-	-	-
4081990	MISC TAXES - OTHER	583266	IDAHO KILOWATT HOUR TAX	SE	58	1	15	4	9	26	4	0	-
4081990	MISC TAXES - OTHER	583267	WYOMING ANNUAL CORPORATION FEE (TAX)	WYP	105	-	-	-	105	-	-	-	-
4081990	MISC TAXES - OTHER	583269	MONTANA WHOLESALE ENERGY TAX	SE	270	3	71	18	40	121	16	0	-
4081990	MISC TAXES - OTHER	583273	Wyoming Wind Generation Tax	SG	1,947	27	523	146	268	874	109	0	-
4081990	MISC TAXES - OTHER	583274	Nevada Commerce Tax	SO	13	0	3	1	2	6	1	0	-
4081990	MISC TAXES - OTHER	584100	GOVERNMENT ROYALTIES	SE	498	6	131	34	74	222	30	0	-
4081990 Total					**20,734**	**460**	**6,725**	**1,421**	**2,579**	**8,498**	**1,050**	**0**	**-**
Grand Total					**188,692**	**5,327**	**74,630**	**11,173**	**21,469**	**67,775**	**8,318**	**0**	**-**

B6. FEDERAL INCOME TAXES

PACIFICORP

Interest Expense & Renewable Energy Tax Credits
Twelve Months Ended - June 2023
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Acct		Alloc	Total	California	Oregon	Washington	Wyoming	Utah	Idaho	FERC	Other
4091000	INC TX UTIL OP INC	310310	Renewable Electricity Production Tax Cre	SG	(196,378)	(2,704)	(52,794)	(14,705)	(27,053)	(88,135)	(10,986)	(0)	-
4091000	INC TX UTIL OP INC	600600	Fuel Tax Credit	SE	(3)	(0)	(1)	(0)	(0)	(1)	(0)	(0)	-
4091000	INC TX UTIL OP INC	900900	Foreign Tax Credit	SO	(39)	(1)	(11)	(3)	(5)	(17)	(2)	(0)	-
4091000 Total					**(196,419)**	**(2,705)**	**(52,806)**	**(14,708)**	**(27,059)**	**(88,153)**	**(10,988)**	**(0)**	**-**
4191000		0	AFUDC - EQUITY	SNP	(103,525)	(2,940)	(27,057)	(7,277)	(12,989)	(47,564)	(5,698)	(0)	-
4191000 Total					**(103,525)**	**(2,940)**	**(27,057)**	**(7,277)**	**(12,989)**	**(47,564)**	**(5,698)**	**(0)**	**-**
4270000	INT ON LNG-TRM DBT	585001	INTEREST EXPENSE - LONG-TERM DEBT - FMBS	SNP	411,783	11,694	107,623	28,946	51,664	189,191	22,665	0	-
4270000	INT ON LNG-TRM DBT	585002	INTEREST EXPENSE - LONG-TERM DEBT - MTNS	SNP	19,598	557	5,122	1,378	2,459	9,004	1,079	0	-
4270000	INT ON LNG-TRM DBT	585004	INTEREST EXPENSE - LT DEBT - PCRBS VARIA	SNP	5,738	163	1,500	403	720	2,636	316	0	-
4270000	INT ON LNG-TRM DBT	585005	INTEREST EXPENSE - LT DEBT - PCRB FEES &	SNP	702	20	183	49	88	322	39	0	-
4270000 Total					**437,821**	**12,434**	**114,428**	**30,776**	**54,931**	**201,154**	**24,098**	**0**	**-**
4280000	AMT DBT DISC & EXP	586160	AMORTIZATION - DEBT DISCOUNT	SNP	1,341	38	350	94	168	616	74	0	-
4280000	AMT DBT DISC & EXP	586170	AMORTIZATION - DEBT ISSUANCE EXP	SNP	3,336	95	872	235	419	1,533	184	0	-
4280000 Total					**4,677**	**133**	**1,222**	**329**	**587**	**2,149**	**257**	**0**	**-**
4281000	AMORTZN OF LOSS	586190	AMORTIZATION - LOSS ON REQACQUIRED DEBT	SNP	404	11	106	28	51	186	22	0	-
4281000 Total					**404**	**11**	**106**	**28**	**51**	**186**	**22**	**0**	**-**
4290000	AMT PREM ON DEBT	586180	AMORTIZATION - DEBT PREMIUM/GAIN	SNP	(2)	(0)	(0)	(0)	(0)	(1)	(0)	(0)	-
4290000 Total					**(2)**	**(0)**	**(0)**	**(0)**	**(0)**	**(1)**	**(0)**	**(0)**	**-**
4310000	OTHER INTEREST EXP	0	4310000/0	SNP	28,782	817	7,522	2,023	3,611	13,224	1,584	0	-
4310000	OTHER INTEREST EXP	570019	Federal uncertain tax position int incom	SNP	(15)	(0)	(4)	(1)	(2)	(7)	(1)	(0)	-
4310000	OTHER INTEREST EXP	575039	State uncertain tax position int income	SNP	(2)	(0)	(0)	(0)	(0)	(1)	(0)	(0)	-
4310000	OTHER INTEREST EXP	575059	Current state tax interest income	SNP	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	-
4310000 Total					**28,765**	**817**	**7,518**	**2,022**	**3,609**	**13,216**	**1,583**	**0**	**-**
4313000	INT EXP ON REG LIAB	0	INTEREST EXPENSE ON REG LIABILITIES	SNP	2,506	71	655	176	314	1,151	138	0	-
4313000 Total					**2,506**	**71**	**655**	**176**	**314**	**1,151**	**138**	**0**	**-**
4320000	AFUDC - BORROWED	585800	INTEREST CAPITALIZED (SEE OTH INCOME)	SNP	(48,010)	(1,363)	(12,548)	(3,375)	(6,023)	(22,058)	(2,643)	(0)	-
4320000	AFUDC - BORROWED	585860	INTEREST EXPENSE - AFUDC MANUAL ADJ	SNP	493	14	129	35	62	226	27	0	-
4320000 Total					**(47,517)**	**(1,349)**	**(12,419)**	**(3,340)**	**(5,962)**	**(21,831)**	**(2,615)**	**(0)**	**-**
Grand Total					**126,711**	**6,472**	**31,647**	**8,006**	**13,482**	**60,307**	**6,797**	**0**	**-**

PACIFICORP

Schedule M (Actuals)
Twelve Months Ending - June 2023
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

FERC Account	FERC Secondary Acct		JARS Reg Alloc Fctr	Total	California	Oregon	Washington	Wyoming	Utah	Idaho	FERC	Other
SCHMAP	105127	Book Depr Allocated to Medicare and M&E	SCHMDEXP	153	4	41	11	20	69	8	0	-
SCHMAP	130100	Non - Deductible Expenses	SO	918	24	252	67	117	408	50	0	-
SCHMAP	130400	PMINondeductible Exp	SE	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	-
SCHMAP	130505	Executive Compensation 162(m)	SO	1,018	27	279	74	129	452	55	0	-
SCHMAP	130750	Nondeductible Fringe Benefits	SO	128	3	35	9	16	57	7	0	-
SCHMAP	130755	Nondeductible Parking Costs	SO	535	14	147	39	68	238	29	0	-
SCHMAP	505505	Income Tax Interest	SO	0	0	0	0	0	0	0	0	-
SCHMAP	610106	PMIFuel Tax Cr	SE	3	0	1	0	0	1	0	0	-
SCHMAP	610107	PMI Dividend Gross Up for Foreign Tax Cr	SO	39	1	11	3	5	17	2	0	-
SCHMAP Total				**2,793**	**73**	**765**	**205**	**356**	**1,243**	**152**	**0**	**-**
SCHMAT	105100	Capitalized Labor Costs	SO	4,556	120	1,250	333	579	2,026	248	0	-
SCHMAT	105120	Book Depreciation	SCHMDEXP	1,086,393	26,839	291,288	80,460	142,092	486,104	59,609	0	-
SCHMAT	105121	PMIBook Depreciation	SE	6,260	80	1,649	427	930	2,798	377	0	-
SCHMAT	105130	CIAC	CIAC	137,504	9,281	34,374	7,965	11,824	67,239	6,821	-	-
SCHMAT	105140	Highway relocation	SNPD	2,643	178	661	153	227	1,292	131	-	-
SCHMAT	105142	Avoided Costs	SNP	90,682	2,575	23,701	6,374	11,377	41,663	4,991	0	-
SCHMAT	105471	UT Kalamath Relicensing Costs	OTHER	(32,081)	-	-	-	-	-	-	-	(32,081)
SCHMAT	210200	Prepaid Taxes-property taxes	GPS	(1,595)	(42)	(438)	(117)	(203)	(709)	(87)	(0)	-
SCHMAT	220100	Bad Debts Allowance - Cash Basis	BADDEBT	5,482	163	2,135	1,482	279	1,323	100	-	-
SCHMAT	320270	Reg Asset FAS 158 Pension Liab Adj	SO	34,175	897	9,373	2,500	4,346	15,196	1,863	0	-
SCHMAT	320280	Reg Asset FAS 158 Post Retire Liab	SO	(8,644)	(227)	(2,371)	(632)	(1,099)	(3,843)	(471)	(0)	-
SCHMAT	320281	Reg Asset - Post-Retirement Settlement L	SO	930	24	255	68	118	413	51	0	-
SCHMAT	415115	Reg Asset - UT STEP Pilot Programs Balan	OTHER	(4,721)	-	-	-	-	-	-	-	(4,721)
SCHMAT	415251	Reg Asset - Low Carbon Energy Standards	OTHER	256	-	-	-	-	-	-	-	256
SCHMAT	415252	Reg Asset - Distribution System Plan - O	OTHER	(1,495)	-	-	-	-	-	-	-	(1,495)
SCHMAT	415261	Reg Asset-UT Wildland Fire Protection	OTHER	(10,017)	-	-	-	-	-	-	-	(10,017)
SCHMAT	415262	Reg Asset -Wildfire Mitigation Account -	OTHER	(52,673)	-	-	-	-	-	-	-	(52,673)
SCHMAT	415263	Reg Asset - Wildfire Damaged Asset - OR	OR	(137)	-	(137)	-	-	-	-	-	-
SCHMAT	415264	Reg Asset - TB Flats - OR	OTHER	(6,889)	-	-	-	-	-	-	-	(6,889)
SCHMAT	415270	Reg Asset - Electric Vehicle Charging In	OTHER	5,200	-	-	-	-	-	-	-	5,200
SCHMAT	415301	Environmental Costs WA	WA	357	-	-	357	-	-	-	-	-
SCHMAT	415305	Reg Asset - Cedar Springs II - OR	OTHER	(275)	-	-	-	-	-	-	-	(275)
SCHMAT	415424	Contra Reg Asset - Deer Creek Abandonmen	SE	5,520	70	1,454	377	820	2,467	332	0	-
SCHMAT	415426	Reg Asset - 2020 GRC - Meters Replaced b	OTHER	2,754	-	-	-	-	-	-	-	2,754
SCHMAT	415430	Reg Asset - CA - Transportation Electri	OTHER	10	-	-	-	-	-	-	-	10
SCHMAT	415702	Reg Asset - Lake Side Liq.	WYP	27	-	-	-	27	-	-	-	-
SCHMAT	415703	Goodnoe Hills Liquidation Damages - WY	WYP	21	-	-	-	21	-	-	-	-
SCHMAT	415710	Reg Liability - WA - Accelerated Depreci	WA	(17,418)	-	-	(17,418)	-	-	-	-	-
SCHMAT	415728	Contra Reg Asset - Cholla U4 Closure - O	OTHER	(709)	-	-	-	-	-	-	-	(709)
SCHMAT	415734	Reg Asset - Cholla Unrecovered Plant - C	CA	241	241	-	-	-	-	-	-	-
SCHMAT	415736	Reg Asset - Cholla Unrecovered Plant - W	WYP	3,810	-	-	-	3,810	-	-	-	-
SCHMAT	415840	Reg Asset-Deferred OR Independent Evalua	OTHER	(77)	-	-	-	-	-	-	-	(77)
SCHMAT	415841	Reg Asset - Emergency Service Programs -	OTHER	(188)	-	-	-	-	-	-	-	(188)
SCHMAT	415855	CA - January 2010 Storm Costs	OTHER	506	-	-	-	-	-	-	-	506

PACIFICORP

Schedule M (Actuals)
Twelve Months Ending - June 2023
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

FERC Account	FERC Secondary Acct		JARS Reg Alloc Fctr	Total	California	Oregon	Washington	Wyoming	Utah	Idaho	FERC	Other
SCHMAT	415857	ID - Deferred Overburden Costs	OTHER	88	-	-	-	-	-	-	-	88
SCHMAT	415858	WY - Deferred Overburden Costs	WYP	253	-	-	-	253	-	-	-	-
SCHMAT	415865	Reg Asset - UT MPA	OTHER	(0)	-	-	-	-	-	-	-	(0)
SCHMAT	415868	Reg Asset - UT - Solar Incentive Program	OTHER	4,258	-	-	-	-	-	-	-	4,258
SCHMAT	415876	Deferred Excess Net PowerCosts - OR	OTHER	(119,809)	-	-	-	-	-	-	-	(119,809)
SCHMAT	415926	Reg Liability - Depreciation Decrease -	OTHER	(2,715)	-	-	-	-	-	-	-	(2,715)
SCHMAT	415938	Reg Asset - Carbon Plant Decommissioning	CA	(52)	(52)	-	-	-	-	-	-	-
SCHMAT	415942	Reg Liability - Steam Decommissioning -	WA	3,570	-	-	3,570	-	-	-	-	-
SCHMAT	425105	Reg Asset - OR Asset Sale Gain Giveback	OTHER	(859)	-	-	-	-	-	-	-	(859)
SCHMAT	425360	Hermiston Swap	SG	172	2	46	13	24	77	10	0	-
SCHMAT	425380	Idaho Customer Balancing Account	OTHER	(1,043)	-	-	-	-	-	-	-	(1,043)
SCHMAT	430100	Customer Service / Weatherization	OTHER	(12,099)	-	-	-	-	-	-	-	(12,099)
SCHMAT	505125	ACCRUED ROYALTIES	SE	597	8	157	41	89	267	36	0	-
SCHMAT	505400	Bonus Liability	SO	(353)	(9)	(97)	(26)	(45)	(157)	(19)	(0)	-
SCHMAT	505450	Accrued Payroll Taxes	SO	(12,550)	(329)	(3,442)	(918)	(1,596)	(5,580)	(684)	(0)	-
SCHMAT	5054501	Accrued Payroll Taxes - PMI	SE	(504)	(6)	(133)	(34)	(75)	(225)	(30)	(0)	-
SCHMAT	505520	Bonus Accrual - PMI	SE	37	0	10	3	5	17	2	0	-
SCHMAT	505525	Accrued Severance -PMI	SE	(62)	(1)	(16)	(4)	(9)	(28)	(4)	(0)	-
SCHMAT	505600	Sick Leave Vacation & Personal Time	SO	2,779	73	762	203	353	1,236	152	0	-
SCHMAT	505601	Sick Leave Accrual - PMI	SE	(14)	(0)	(4)	(1)	(2)	(6)	(1)	(0)	-
SCHMAT	505700	Accrued Retention Bonus	SO	(13)	(0)	(3)	(1)	(2)	(6)	(1)	(0)	-
SCHMAT	605100	Trojan Decomissioning Costs	TROJD	(372)	(5)	(100)	(27)	(52)	(167)	(21)	(0)	-
SCHMAT	605710	Reverse Accrued Final Reclamation	OTHER	(306)	-	-	-	-	-	-	-	(306)
SCHMAT	605715	Trapper Mine Contract Obligation	SE	2,250	29	593	153	334	1,005	135	0	-
SCHMAT	610141	WA Rate Refunds	OTHER	(2,847)	-	-	-	-	-	-	-	(2,847)
SCHMAT	610145	REG LIAB-DSM	OTHER	2,095	-	-	-	-	-	-	-	2,095
SCHMAT	610150	REG LIABILITY - BRIDGER MINE ACCELERATED	OR	3,637	-	3,637	-	-	-	-	-	-
SCHMAT	610155	Reg Liability - Plant Closure Cost - WA	WA	1,356	-	-	1,356	-	-	-	-	-
SCHMAT	705240	CA Alternative Rate for Energy Program(C	OTHER	(452)	-	-	-	-	-	-	-	(452)
SCHMAT	705241	Reg Liability - CA California Alternativ	OTHER	(192)	-	-	-	-	-	-	-	(192)
SCHMAT	705245	REG LIABILITY - OR DIRECT ACCESS 5 YEAR	OTHER	(1,617)	-	-	-	-	-	-	-	(1,617)
SCHMAT	705263	Reg Liability - Sale of REC's-WA	OTHER	78	-	-	-	-	-	-	-	78
SCHMAT	705266	Reg Liability - Energy Savings Assistanc	OTHER	(253)	-	-	-	-	-	-	-	(253)
SCHMAT	705267	Reg Liability - WA Decoupling Mechanism	OTHER	6,022	-	-	-	-	-	-	-	6,022
SCHMAT	705336	Reg Liability - Sale of Renewable Energy	OTHER	913	-	-	-	-	-	-	-	913
SCHMAT	705340	Reg Liability - Excess Income Tax Deferr	OTHER	(1,559)	-	-	-	-	-	-	-	(1,559)
SCHMAT	705342	Reg Liability - Excess Income Tax Deferr	OTHER	(3,319)	-	-	-	-	-	-	-	(3,319)
SCHMAT	705344	Reg Liability - Excess Income Tax Deferr	OTHER	(1,519)	-	-	-	-	-	-	-	(1,519)
SCHMAT	705345	Reg Liability - Excess Income Tax Deferr	OTHER	21	-	-	-	-	-	-	-	21
SCHMAT	705352	Reg Liability - CA Klamath River Dams Re	CA	1	1	-	-	-	-	-	-	-
SCHMAT	705400	Reg Liability - OR Injuries & Damages Re	OR	(8,898)	-	(8,898)	-	-	-	-	-	-
SCHMAT	705410	Reg Liability - Cholla Decommissioning -	CA	(38)	(38)	-	-	-	-	-	-	-
SCHMAT	705411	Reg Liability - Cholla Decommissioning -	IDU	(140)	-	-	-	-	-	(140)	-	-
SCHMAT	705412	Reg Liability - Cholla Decommissioning -	OR	(618)	-	(618)	-	-	-	-	-	-
SCHMAT	705413	Reg Liability - Cholla Decommissioning -	UT	(1,046)	-	-	-	-	(1,046)	-	-	-

PACIFICORP

Schedule M (Actuals)
Twelve Months Ending - June 2023
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

FERC Account	FERC Secondary Acct		JARS Reg Alloc Fctr	Total	California	Oregon	Washington	Wyoming	Utah	Idaho	FERC	Other
SCHMAT	705414	Reg Liability - Cholla Decommissioning -	WYP	270	-	-	-	270	-	-	-	-
SCHMAT	705420	Reg Liability - CA GHG Allowance Revenue	OTHER	6,915	-	-	-	-	-	-	-	6,915
SCHMAT	705425	Reg Liability - Bridger Mine Accelerated	WA	2,549	-	-	2,549	-	-	-	-	-
SCHMAT	705450	Reg Liability - Property Insurance Reser	CA	(4,621)	(4,621)	-	-	-	-	-	-	-
SCHMAT	705451	Reg Liability - OR Property Insurance Re	OR	(5,492)	-	(5,492)	-	-	-	-	-	-
SCHMAT	705452	Reg Liability - Property Insurance Reser	WA	(311)	-	-	(311)	-	-	-	-	-
SCHMAT	705455	Reg Liability - WY Property Insurance Re	WYP	(373)	-	-	-	(373)	-	-	-	-
SCHMAT	705511	Regulatory Liability - CA Deferred Exces	OTHER	1,614	-	-	-	-	-	-	-	1,614
SCHMAT	705515	Regulatory Liability - OR Deferred Exces	OTHER	(3,970)	-	-	-	-	-	-	-	(3,970)
SCHMAT	705531	Regulatory Liability - UT Solar Feed-in	OTHER	(5,092)	-	-	-	-	-	-	-	(5,092)
SCHMAT	715105	MCI FOG Wire Lease	SG	(1,724)	(24)	(463)	(129)	(237)	(774)	(96)	(0)	-
SCHMAT	715720	NW Power Act-WA	OTHER	(123)	-	-	-	-	-	-	-	(123)
SCHMAT	720300	Pension / Retirement (Accrued / Prepaid)	SO	(216)	(6)	(59)	(16)	(27)	(96)	(12)	(0)	-
SCHMAT	740100	Post Merger Loss-Reacquired Debt	SNP	404	11	106	28	51	186	22	0	-
SCHMAT	910245	Contra Receivable from Joint Owners	SO	(145)	(4)	(40)	(11)	(18)	(64)	(8)	(0)	-
SCHMAT	910905	Bridger Coal Company Underground Mine Co	SE	(82)	(1)	(22)	(6)	(12)	(36)	(5)	(0)	-
SCHMAT	920110	PMIWY Extraction Tax	SE	(3,193)	(41)	(841)	(218)	(474)	(1,427)	(192)	(0)	-
SCHMAT Total				**1,091,695**	**35,188**	**348,275**	**88,543**	**173,605**	**609,144**	**73,108**	**0**	**#####**
SCHMDP	1102051	TAX PERCENTAGE DEPLETION - DEDUCTION	SE	444	6	117	30	66	199	27	0	-
SCHMDP	120100	Preferred Dividend - PPL	SNP	114	3	30	8	14	52	6	0	-
SCHMDP	910900	PMIDepletion	SE	3,089	39	814	211	459	1,381	186	0	-
SCHMDP Total				**3,647**	**48**	**960**	**249**	**539**	**1,631**	**219**	**0**	**-**
SCHMDT	105122	Repair Deduction	SG	173,185	2,385	46,559	12,968	23,858	77,726	9,688	0	-
SCHMDT	105125	Tax Depreciation	TAXDEPR	1,264,819	34,755	332,584	91,863	157,813	576,124	71,576	0	105
SCHMDT	105126	PMITax Depreciation	SE	2,439	31	642	166	362	1,090	147	0	-
SCHMDT	105137	Capitalized Depreciation	SO	10,828	284	2,970	792	1,377	4,815	590	0	-
SCHMDT	1051411	AFUDC - DEBT	SNP	47,394	1,346	12,387	3,331	5,946	21,775	2,609	0	-
SCHMDT	1051412	AFUDC - Equity	SNP	103,255	2,932	26,987	7,258	12,955	47,440	5,683	0	-
SCHMDT	105143	Basis Intangible Difference	SNP	394	11	103	28	49	181	22	0	-
SCHMDT	105150	CWIP Adjustment ~ PMI	SE	2,077	26	547	142	309	928	125	0	-
SCHMDT	105152	Gain/(Loss) on Prop Dispositions	GPS	53,986	1,416	14,806	3,950	6,866	24,005	2,944	0	-
SCHMDT	105175	Removal Cost (net of salvage)	GPS	75,936	1,992	20,826	5,556	9,657	33,765	4,140	0	-
SCHMDT	105470	Book Gain/Loss on Land Sales	GPS	477	13	131	35	61	212	26	0	-
SCHMDT	1102051	Tax Percentage Depletion - Deduction	SE	154	2	41	11	23	69	9	0	-
SCHMDT	205025	PMI - Fuel Cost Adjustment	SE	12,564	160	3,309	857	1,867	5,616	756	0	-
SCHMDT	205200	Coal M&S Inventory Write-Off	SNPD	150	10	38	9	13	74	7	-	-
SCHMDT	205411	PMISEC 263A Adjustment	SE	1,725	22	454	118	256	771	104	0	-
SCHMDT	210100	Prepaid Taxes-OR PUC	OR	139	-	139	-	-	-	-	-	-
SCHMDT	210120	Prepaid Taxes-UT PUC	UT	134	-	-	-	-	134	-	-	-
SCHMDT	210130	Prepaid Taxes-ID PUC	IDU	19	-	-	-	-	-	19	-	-
SCHMDT	210170	Prepaid Lease-Gadsby Gas Turbine	SG	769	11	207	58	106	345	43	0	-
SCHMDT	210175	Prepaid - FSA O&M - East	SG	1,955	27	526	146	269	877	109	0	-
SCHMDT	210180	OTHER PREPAIDS	SO	265	7	73	19	34	118	14	0	-
SCHMDT	210185	Prepaid Aircraft Maintenance Costs	SG	(44)	(1)	(12)	(3)	(6)	(20)	(2)	(0)	-

PACIFICORP

Schedule M (Actuals)
Twelve Months Ending - June 2023
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

FERC Account	FERC Secondary Acct		JARS Reg Alloc Fctr	Total	California	Oregon	Washington	Wyoming	Utah	Idaho	FERC	Other
SCHMDT	210190	Prepaid Water Rights	SG	62	1	17	5	9	28	3	0	-
SCHMDT	320279	Reg Liability - FAS 158 Post Retirement	SO	(7,029)	(184)	(1,928)	(514)	(894)	(3,126)	(383)	(0)	-
SCHMDT	320286	Reg Asset - Pension Settlement - OR	OTHER	6,510	-	-	-	-	-	-	-	6,510
SCHMDT	320287	Reg Asset - Pension Settlement - UT	OTHER	3,013	-	-	-	-	-	-	-	3,013
SCHMDT	320288	Reg Asset - Pension Settlement - WY	WYU	3,018	-	-	-	3,018	-	-	-	-
SCHMDT	415100	Reg Asset -WA Equity Advisory Group (CET	OTHER	319	-	-	-	-	-	-	-	319
SCHMDT	415110	Def Reg Asset-Transmission Srvc Deposit	SG	(4,645)	(64)	(1,249)	(348)	(640)	(2,085)	(260)	(0)	-
SCHMDT	415200	REG ASSET - OR TRANSPORTATION ELECTRIFIC	OTHER	(2,254)	-	-	-	-	-	-	-	(2,254)
SCHMDT	415255	Reg Asset-WY Wind Test Energy Deferral	WYU	(8)	-	-	-	(8)	-	-	-	-
SCHMDT	415260	Reg Asset - Fire Risk Mitigation - CA	OTHER	7,824	-	-	-	-	-	-	-	7,824
SCHMDT	415300	Hazardous Waste Clean-up Costs	SO	33,203	871	9,106	2,429	4,223	14,764	1,810	0	-
SCHMDT	415410	Reg Asset - Energy West Mining	SE	504	6	133	34	75	225	30	0	-
SCHMDT	415411	ContraRA DeerCreekAband CA	CA	(9)	(9)	-	-	-	-	-	-	-
SCHMDT	415412	ContraRA DeerCreekAband ID	IDU	955	-	-	-	-	-	955	-	-
SCHMDT	415413	ContraRA DeerCreekAband OR	OR	3,686	-	3,686	-	-	-	-	-	-
SCHMDT	415415	ContraRA DeerCreekAband WA	WA	8	-	-	8	-	-	-	-	-
SCHMDT	415416	ContraRA DeerCreekAband WY	WYU	(347)	-	-	-	(347)	-	-	-	-
SCHMDT	415431	Reg Asset - WA Transportation Electrific	OTHER	193	-	-	-	-	-	-	-	193
SCHMDT	415440	Reg Asset - Low Income Bill Discount - O	OTHER	3,383	-	-	-	-	-	-	-	3,383
SCHMDT	415441	Reg Asset - Utility Community Advisory G	OTHER	133	-	-	-	-	-	-	-	133
SCHMDT	415445	Reg Asset - Klamath Unrecovered Plant &	SG	(654)	(9)	(176)	(49)	(90)	(293)	(37)	(0)	-
SCHMDT	415520	Reg Asset - WA Decoupling Mechanism	OTHER	(5,571)	-	-	-	-	-	-	-	(5,571)
SCHMDT	415655	CA GHG Allowance	OTHER	749	-	-	-	-	-	-	-	749
SCHMDT	415675	Reg Asset - UT - Deferred Stock Redempti	OTHER	(83)	-	-	-	-	-	-	-	(83)
SCHMDT	415676	Reg Asset - WY - Deferred Stock Redempti	OTHER	(28)	-	-	-	-	-	-	-	(28)
SCHMDT	415677	Reg Asset - Pref Stock Redemp Loss WA	OTHER	(13)	-	-	-	-	-	-	-	(13)
SCHMDT	415680	Deferred Intervenor Funding Grants-OR	OTHER	803	-	-	-	-	-	-	-	803
SCHMDT	415701	CA Deferred Intervenor Funding	OTHER	23	-	-	-	-	-	-	-	23
SCHMDT	415720	Reg Asset - Community Solar - OR	OTHER	843	-	-	-	-	-	-	-	843
SCHMDT	415815	Insurance Reserve	SO	122,900	3,224	33,706	8,992	15,630	54,647	6,701	0	-
SCHMDT	415833	Reg Asset - Pension Settlement - CA	OTHER	524	-	-	-	-	-	-	-	524
SCHMDT	415862	Reg Asset - CA Mobile Home Park Conversi	OTHER	(12)	-	-	-	-	-	-	-	(12)
SCHMDT	415863	Reg Asset - UT Subscriber Solar Program	UT	(39)	-	-	-	-	(39)	-	-	-
SCHMDT	415866	Reg Asset - OR Solar Feed-in Tariff	OTHER	(780)	-	-	-	-	-	-	-	(780)
SCHMDT	415870	CA Def Excess NPC	OTHER	12,888	-	-	-	-	-	-	-	12,888
SCHMDT	415874	Deferred Excess Net Power Costs - WY 08	OTHER	83,149	-	-	-	-	-	-	-	83,149
SCHMDT	415875	Deferred Excess Net Power Costs - UT	OTHER	222,204	-	-	-	-	-	-	-	222,204
SCHMDT	415878	REG ASSET - UT LIQUIDATED DAMAGES NAUGHT	UT	(35)	-	-	-	-	(35)	-	-	-
SCHMDT	415879	Reg Asset - WY Liquidation Damages N2	WYP	(6)	-	-	-	(6)	-	-	-	-
SCHMDT	415882	Deferral of Renewable Energy Credit - WA	OTHER	(286)	-	-	-	-	-	-	-	(286)
SCHMDT	415885	Reg Asset - Noncurrent Reclass - Other	OTHER	50	-	-	-	-	-	-	-	50
SCHMDT	415892	Deferred Excess Net Power Costs - ID 09	OTHER	22,702	-	-	-	-	-	-	-	22,702
SCHMDT	415906	Reg Asset - REC Sales Deferral - OR - No	OTHER	117	-	-	-	-	-	-	-	117
SCHMDT	415920	Reg Asset - Depreciation Increase - ID	IDU	(3,485)	-	-	-	-	-	(3,485)	-	-
SCHMDT	415921	Reg Asset - Depreciation Increase - UT	UT	(128)	-	-	-	-	(128)	-	-	-

PACIFICORP

Schedule M (Actuals)
Twelve Months Ending - June 2023
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

FERC Account	FERC Secondary Acct		JARS Reg Alloc Fctr	Total	California	Oregon	Washington	Wyoming	Utah	Idaho	FERC	Other
SCHMDT	415922	Reg Asset - Depreciation Increase - WY	WYP	(442)	-	-	-	(442)	-	-	-	-
SCHMDT	415924	Reg Asset - Carbon Unrecovered Plant - U	UT	4,979	-	-	-	-	4,979	-	-	-
SCHMDT	415929	Reg Asset - Carbon Decommissioning - CA	CA	(202)	(202)	-	-	-	-	-	-	-
SCHMDT	415933	Reg Liability - Contra - Carbon Decommis	IDU	(2,775)	-	-	-	-	-	(2,775)	-	-
SCHMDT	415934	Reg Liability - Contra - Carbon Decommis	UT	(17,054)	-	-	-	-	(17,054)	-	-	-
SCHMDT	415935	Reg Liability - Contra - Carbon Decommis	WYP	(5,669)	-	-	-	(5,669)	-	-	-	-
SCHMDT	415936	REG ASSET - CARBON PLANT DECOMMISSIONING	SG	(746)	(10)	(200)	(56)	(103)	(335)	(42)	(0)	-
SCHMDT	415943	Reg Asset - Covid-19 Bill Assistance Pro	OTHER	(62)	-	-	-	-	-	-	-	(62)
SCHMDT	425215	Unearned Joint Use Pole Contact Revenue	SNPD	(106)	(7)	(27)	(6)	(9)	(52)	(5)	-	-
SCHMDT	425400	UT Kalamath Relicensing Costs	OTHER	(2,089)	-	-	-	-	-	-	-	(2,089)
SCHMDT	430110	Reg Asset balance reclass	OTHER	2,095	-	-	-	-	-	-	-	2,095
SCHMDT	430112	Reg Asset - Other - Balance Reclass	OTHER	10,730	-	-	-	-	-	-	-	10,730
SCHMDT	505510	Vacation Accrual - PMI	SE	64	1	17	4	10	29	4	0	-
SCHMDT	605103	ARO/Reg Diff - Trojan - WA	WA	(116)	-	-	(116)	-	-	-	-	-
SCHMDT	610100	PMIDEVT COST AMORT	SE	(336)	(4)	(88)	(23)	(50)	(150)	(20)	(0)	-
SCHMDT	6101001	AMORT NOPAS 99-00 RAR	SO	139	4	38	10	18	62	8	0	-
SCHMDT	610111	Bridger Coal Company Gain/Loss on Assets	SE	3,469	44	914	237	515	1,551	209	0	-
SCHMDT	610114	PMI EITF Pre Stripping Costs	SE	4,059	52	1,069	277	603	1,814	244	0	-
SCHMDT	610146	OR Reg Asset/Liability Consolidation	OR	13	-	13	-	-	-	-	-	-
SCHMDT	705261	Reg Liability - Sale of Renewable Energy	OTHER	343	-	-	-	-	-	-	-	343
SCHMDT	705265	Reg Liab - OR Energy Conservation Charge	OTHER	(902)	-	-	-	-	-	-	-	(902)
SCHMDT	705337	Reg Liability - Sale of Renewable Energy	OTHER	(400)	-	-	-	-	-	-	-	(400)
SCHMDT	705454	Reg Liability - UT Property Insurance Re	UT	1,463	-	-	-	-	1,463	-	-	-
SCHMDT	705755	Reg Liability - Non current Reclass - Ot	OTHER	(50)	-	-	-	-	-	-	-	(50)
SCHMDT	715295	Reg Liability - Fly Ash - OR	OTHER	(1,402)	-	-	-	-	-	-	-	(1,402)
SCHMDT	720200	Deferred Comp Plan Benefits-PPL	SO	(168)	(4)	(46)	(12)	(21)	(75)	(9)	(0)	-
SCHMDT	720500	Severance Accrual	SO	(63)	(2)	(17)	(5)	(8)	(28)	(3)	(0)	-
SCHMDT	720805	FAS 158 - Funded Pension Asset	SO	13,189	346	3,617	965	1,677	5,864	719	0	-
SCHMDT	720815	FAS 158 Post Retirement Liability	SO	1,155	30	317	84	147	513	63	0	-
SCHMDT	910530	Injuries and Damages Reserve	SO	(476,956)	(12,513)	(130,807)	(34,896)	(60,657)	(212,078)	(26,006)	(0)	-
SCHMDT Total				**1,789,130**	**36,999**	**381,409**	**104,324**	**178,795**	**646,505**	**76,331**	**0**	**364,767**
Grand Total				**2,887,265**	**72,308**	**731,409**	**193,321**	**353,296**	**1,258,524**	**149,810**	**0**	**128,598**

B7. D.I.T. EXPENSE AND I.T.C. ADJUSTMENT

PACIFICORP

Deferred Income Tax Expense (Actuals)
Twelve Months Ending - June 2023
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
4101000	100105	190FAS 109 DEF TAX LIAB WA-NUTIL	WA		-	-	-	-	-	-	-	-
4101000	105101	Capitalized Labor Cost for Powertax Inpu	SO		-	-	-	-	-	-	-	-
4101000	105121	282PMI Book Depreciation	SE		-	-	-	-	-	-	-	-
4101000	105122	Repair Deduction	SG	42,580	586	11,447	3,189	5,866	19,110	2,382	0	-
4101000	105125	Tax Depreciation	TAXDEPR	310,976	8,545	81,771	22,586	38,801	141,649	17,598	0	26
4101000	105126	282DIT PMIDepreciation-Tax	SE	600	8	158	41	89	268	36	0	-
4101000	105137	Capitalized Depreciation	SO	2,662	70	730	195	339	1,184	145	0	-
4101000	105141	AFUDC Debt	SNP	11,653	331	3,045	819	1,462	5,354	641	0	-
4101000	1051411	AFUDC Equity	SNP	25,387	721	6,635	1,785	3,185	11,664	1,397	0	-
4101000	105143	282Basis Intangible Difference	SNP	97	3	25	7	12	44	5	0	-
4101000	105147	Sec 1031 Like Kind Exchange	SO		-	-	-	-	-	-	-	-
4101000	105148	Mine Safety Sec. 179E Election - PPW	SE		-	-	-	-	-	-	-	-
4101000	105149	Mine Safety Sec. 179E Election - PMI	SE		-	-	-	-	-	-	-	-
4101000	105150	CWIP Adjustment ~ PMI	SE	511	6	135	35	76	228	31	0	-
4101000	105152	Gain / (Loss) on Prop. Disposition	GPS	13,273	348	3,640	971	1,688	5,902	724	0	-
4101000	105153	Contract Liability Basis Adjustment -Che	SG		-	-	-	-	-	-	-	-
4101000	105165	Coal Mine Development	SE		-	-	-	-	-	-	-	-
4101000	105170	Coal Mine Extension	SE		-	-	-	-	-	-	-	-
4101000	105171	PMI Coal Mine Extension Costs	SE		-	-	-	-	-	-	-	-
4101000	105175	Cost of Removal	GPS	18,670	490	5,120	1,366	2,374	8,302	1,018	0	-
4101000	1052203	Cholla SHL NOPA (Lease Amortization)	SG		-	-	-	-	-	-	-	-
4101000	105470	282Book Gain/Loss on Land Sales	GPS	117	3	32	9	15	52	6	0	-
4101000	110200	IGC Tax Percentage Depletion Deduct	SE		-	-	-	-	-	-	-	-
4101000	110205	SRC Tax Percentage Depletion Deduct	SE		-	-	-	-	-	-	-	-
4101000	1102051	Tax Percentage Depletion - Deduction (Bl	SE	38	0	10	3	6	17	2	0	-
4101000	120105	Willow Wind Account Receivable	WA		-	-	-	-	-	-	-	-
4101000	205025	PMI-Fuel Cost Adjustment	SE	3,089	39	814	211	459	1,381	186	0	-
4101000	205200	M&S INVENTORY WRITE-OFF	SNPD	37	2	9	2	3	18	2	-	-
4101000	205205	Inventory Reserve - PMI	SE		-	-	-	-	-	-	-	-
4101000	205411	190PMISec263A	SE	424	5	112	29	63	190	26	0	-
4101000	210100	283OR PUC Prepaid Taxes	OR	34	-	34	-	-	-	-	-	-
4101000	210120	283UT PUC Prepaid Taxes	UT	33	-	-	-	-	33	-	-	-
4101000	210130	283ID PUC Prepaid Taxes	IDU	5	-	-	-	-	-	5	-	-
4101000	210140	283WY PSC Prepaid Taxes	WYP		-	-	-	-	-	-	-	-
4101000	210170	Prepaid - FSA O&M - West	SG	189	3	51	14	26	85	11	0	-
4101000	210175	Prepaid - FSA O&M - East	SG	481	7	129	36	66	216	27	0	-
4101000	210180	283Prepaid Membership Fees-EEI WSCC	SO	65	2	18	5	8	29	4	0	-
4101000	210185	Prepaid Aircraft Maintenance Costs	SG	(11)	(0)	(3)	(1)	(1)	(5)	(1)	(0)	-
4101000	210190	Prepaid Water Rights	SG	15	0	4	1	2	7	1	0	-
4101000	210195	Prepaid Surety Bond Costs	SO		-	-	-	-	-	-	-	-
4101000	287396	Regulatory Liabilities - Interim Provisi	OTHER		-	-	-	-	-	-	-	-
4101000	287616	Regulatory Assets - Interim Provisions	OTHER		-	-	-	-	-	-	-	-
4101000	320210	190R&E Expense Sec174 Deduction	SO		-	-	-	-	-	-	-	-

PACIFICORP

Deferred Income Tax Expense (Actuals)
Twelve Months Ending - June 2023
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
4101000	320271	Contra Reg Asset - Pension Plan CTG	SO		-	-	-	-	-	-	-	-
4101000	320279	Reg Liability - FAS 158 Post Retirement	SO	(1,728)	(45)	(474)	(126)	(220)	(768)	(94)	(0)	-
4101000	320286	Reg Asset - Pension Settlement - OR	OTHER	1,601	-	-	-	-	-	-	-	1,601
4101000	320287	Reg Asset - Pension Settlement - UT	OTHER	741	-	-	-	-	-	-	-	741
4101000	320288	Reg Asset - Pension Settlement - WY	WYU	742	-	-	-	742	-	-	-	-
4101000	320290	LT Prepaid IBEW 57 Pension Contribution	OTHER		-	-	-	-	-	-	-	-
4101000	320291	Prepaid IBEw 57 Pension Contribution - C	OTHER		-	-	-	-	-	-	-	-
4101000	415100	Reg Asset -WA Equity Advisory Group (CET	OTHER	78	-	-	-	-	-	-	-	78
4101000	415110	190DEF REG ASSET-TRANSM SVC DEPOS	SG	(1,142)	(16)	(307)	(86)	(157)	(513)	(64)	(0)	-
4101000	415120	190DEF REG ASSET-FOOTE CREEK CONT	SG		-	-	-	-	-	-	-	-
4101000	415200	REG ASSET - OR TRANSPORTATION ELEC	OTHER	(554)	-	-	-	-	-	-	-	(554)
4101000	415255	Reg Asset-WY Wind Test Energy Deferral	WYU	(2)	-	-	-	(2)	-	-	-	-
4101000	415260	Reg Asset - Fire Risk Mitigation - CA	OTHER	1,924	-	-	-	-	-	-	-	1,924
4101000	415300	283Hazardous Waste/Environmental Cleanup	SO	8,164	214	2,239	597	1,038	3,630	445	0	-
4101000	415406	Reg Asset Utah ECAM	OTHER		-	-	-	-	-	-	-	-
4101000	415410	Reg Asset - Energy West Mining	SE	124	2	33	8	18	55	7	0	-
4101000	415411	ContraRA DeerCreekAband CA	CA	(2)	(2)	-	-	-	-	-	-	-
4101000	415412	ContraRA DeerCreekAband ID	IDU	235	-	-	-	-	-	235	-	-
4101000	415413	ContraRA DeerCreekAband OR	OR	906	-	906	-	-	-	-	-	-
4101000	415414	ContraRA DeerCreekAband UT	UT		-	-	-	-	-	-	-	-
4101000	415415	ContraRA DeerCreekAband WA	WA	2	-	-	2	-	-	-	-	-
4101000	415416	ContraRA DeerCreekAband WY	WYU	(85)	-	-	-	(85)	-	-	-	-
4101000	415417	Contra RA UMWA Pension CA	OTHER		-	-	-	-	-	-	-	-
4101000	415418	Contra RA UMWA Pension ID	OTHER		-	-	-	-	-	-	-	-
4101000	415419	Contra RA UMWA Pension OR	OTHER		-	-	-	-	-	-	-	-
4101000	415420	Contra RA UMWA Pension UT	OTHER		-	-	-	-	-	-	-	-
4101000	415421	Contra RA UMWA Pension WA	OTHER		-	-	-	-	-	-	-	-
4101000	415422	Contra RA UMWA Pension WY	OTHER		-	-	-	-	-	-	-	-
4101000	415431	Reg Asset - WA Transportation Electrific	OTHER	47	-	-	-	-	-	-	-	47
4101000	415440	Reg Asset - Low Income Bill Discount - O	OTHER	832	-	-	-	-	-	-	-	832
4101000	415441	Reg Asset - Utility Community Advisory G	OTHER	33	-	-	-	-	-	-	-	33
4101000	415445	Reg Asset - Klamath Unrecovered Plant &	SG	(161)	(2)	(43)	(12)	(22)	(72)	(9)	(0)	-
4101000	415501	Cholla Plt Transact Costs- APS Amort - I	IDU		-	-	-	-	-	-	-	-
4101000	415502	Cholla Plt Transact Costs- APS Amort - O	OR		-	-	-	-	-	-	-	-
4101000	415520	Reg Asset - WA Decoupling Mechanism	OTHER	(1,370)	-	-	-	-	-	-	-	(1,370)
4101000	415530	Reg Asset - ID 2017 Protocol - MSP Defer	IDU		-	-	-	-	-	-	-	-
4101000	415531	Reg Asset - UT 2017 Protocol - MSP Defer	UT		-	-	-	-	-	-	-	-
4101000	415532	Reg Asset - WY 2017 Protocol - MSP Defer	WYP		-	-	-	-	-	-	-	-
4101000	415545	Reg Asset - WA Merwin Project	OTHER		-	-	-	-	-	-	-	-
4101000	415585	Reg Asset - OR Sch 203 - Black Cap	OTHER		-	-	-	-	-	-	-	-
4101000	415655	CA GHG Allowance	OTHER	184	-	-	-	-	-	-	-	184
4101000	415675	Reg Asset - UT - Deferred Stock Redempti	OTHER	(20)	-	-	-	-	-	-	-	(20)
4101000	415676	Reg Asset - WY - Deferred Stock Redempti	OTHER	(7)	-	-	-	-	-	-	-	(7)

PACIFICORP

Deferred Income Tax Expense (Actuals)
Twelve Months Ending - June 2023
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
4101000	415677	Reg Asset - Pref Stock Redemp Loss WA	OTHER	(3)	-	-	-	-	-	-	-	(3)
4101000	415680	190Def Intervenor Funding Grants-OR	OTHER	197	-	-	-	-	-	-	-	197
4101000	415700	190Reg Liabs BPA balancing accounts-OR	OTHER		-	-	-	-	-	-	-	-
4101000	415701	CA Deferred Intervenor Funding	OTHER	6	-	-	-	-	-	-	-	6
4101000	415720	Reg Asset - Community Solar - OR	OTHER	207	-	-	-	-	-	-	-	207
4101000	415755	Reg Asset - Major Mtc Exp - Colstrip U4	WA		-	-	-	-	-	-	-	-
4101000	415815	Insurance Reserve	SO	30,217	793	8,287	2,211	3,843	13,436	1,648	0	-
4101000	415820	Contra Pension Reg Asset MMT & CTG OR	OR		-	-	-	-	-	-	-	-
4101000	415821	Contra Pension Reg Asset MMT & CTG WY	WYP		-	-	-	-	-	-	-	-
4101000	415823	Contra Pension Reg Asset CTG - UT	UT		-	-	-	-	-	-	-	-
4101000	415824	Contra Pension Reg Asset MMT & CTG CA	CA		-	-	-	-	-	-	-	-
4101000	415825	Contra Pension Reg Asset CTG - WA	WA		-	-	-	-	-	-	-	-
4101000	415833	Reg Asset - Pension Settlement - CA	OTHER	129	-	-	-	-	-	-	-	129
4101000	415845	Reg Asset - OR Sch 94 Distribution Safet	OTHER		-	-	-	-	-	-	-	-
4101000	415850	Unrecovered Plant Powerdale	SG		-	-	-	-	-	-	-	-
4101000	415851	Powerdale Hydro Decom Reg Asset - CA	CA		-	-	-	-	-	-	-	-
4101000	415862	Reg Asset - CA Mobile Home Park Conversi	OTHER	(3)	-	-	-	-	-	-	-	(3)
4101000	415863	Reg Asset - UT Subscriber Solar Program	UT	(10)	-	-	-	-	(10)	-	-	-
4101000	415866	Reg Asset - OR Solar Feed-in Tariff	OTHER	(192)	-	-	-	-	-	-	-	(192)
4101000	415869	Reg Asset - CA Deferred Net Power Costs	OTHER		-	-	-	-	-	-	-	-
4101000	415870	Deferred Excess Net Power Costs CA	OTHER	3,169	-	-	-	-	-	-	-	3,169
4101000	415874	Deferred Excess Net Power Costs - WY 09	OTHER	20,444	-	-	-	-	-	-	-	20,444
4101000	415875	Deferred Excess Net Power Costs - UT	OTHER	54,632	-	-	-	-	-	-	-	54,632
4101000	415878	REG ASSET - UT LIQUIDATED DAMAGES N	UT	(9)	-	-	-	-	(9)	-	-	-
4101000	415879	Reg Asset - WY Liquidation Damages N2	WYP	(1)	-	-	-	(1)	-	-	-	-
4101000	415882	Deferral of Renewable Energy Credit - WA	OTHER	(70)	-	-	-	-	-	-	-	(70)
4101000	415884	Reg Asset - Current Reclass - Other	OTHER		-	-	-	-	-	-	-	-
4101000	415885	Reg Asset - Noncurrent Reclass - Other	OTHER	12	-	-	-	-	-	-	-	12
4101000	415886	Reg Asset - ID Deferred Excess Net Power	OTHER		-	-	-	-	-	-	-	-
4101000	415888	Reg Asset - UT Deferred Excess Net Power	OTHER		-	-	-	-	-	-	-	-
4101000	415892	Deferred Excess Net Power Costs - ID 09	OTHER	5,582	-	-	-	-	-	-	-	5,582
4101000	415894	Reg Asset - REC Sales Deferral - CA - No	OTHER		-	-	-	-	-	-	-	-
4101000	415900	OR SB 408 Recovery	OTHER		-	-	-	-	-	-	-	-
4101000	415901	Reg Asset - WY Deferred Excess Net Power	OTHER		-	-	-	-	-	-	-	-
4101000	415903	Reg Asset _ REC Sales Deferral - WA	OTHER		-	-	-	-	-	-	-	-
4101000	415904	Reg Asset - WY REC's in Rates - Current	OTHER		-	-	-	-	-	-	-	-
4101000	415905	Reg Asset - OR REC's in Rates - Current	OTHER		-	-	-	-	-	-	-	-
4101000	415906	Reg Asset - REC Sales Deferral - OR - No	OTHER	29	-	-	-	-	-	-	-	29
4101000	415907	Reg Asset - CA Solar Feed-in Tariff - Cu	OTHER		-	-	-	-	-	-	-	-
4101000	415908	Reg Asset - OR Solar Feed-In Tariff - Cu	OTHER		-	-	-	-	-	-	-	-
4101000	415910	Reg Asset - Naughton Unit #3 Costs	OTHER		-	-	-	-	-	-	-	-
4101000	415917	Reg Asset - Naughton Unit #3 Costs - CA	OTHER		-	-	-	-	-	-	-	-
4101000	415918	Reg Asset - RPS Compliance Purchases	OTHER		-	-	-	-	-	-	-	-

PACIFICORP

Deferred Income Tax Expense (Actuals)
Twelve Months Ending - June 2023
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
4101000	415920	Reg Asset - Depreciation Increase - ID	IDU	(857)	-	-	-	-	-	(857)	-	-
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		-	-	-	-	-	-	-	-
4101000	415924	Reg Asset - Carbon Unrecovered Plant - U	UT	1,224	-	-	-	-	1,224	-	-	-
4101000	415925	Reg Asset - Carbon Unrecovered Plant - W	WYP		-	-	-	-	-	-	-	-
4101000	415929	Reg Asset - Carbon Decommissioning - CA	CA	(50)	(50)	-	-	-	-	-	-	-
4101000	415930	Reg Asset - Carbon Decommissioning - ID	IDU		-	-	-	-	-	-	-	-
4101000	415931	Reg Asset - Carbon Decommissioning - UT	UT		-	-	-	-	-	-	-	-
4101000	415932	Reg Asset - Carbon Decommissioning - WY	WYP		-	-	-	-	-	-	-	-
4101000	415933	Reg Liability - Contra - Carbon Decommis	IDU	(682)	-	-	-	-	-	(682)	-	-
4101000	415934	Reg Liability - Contra - Carbon Decommis	UT	(4,193)	-	-	-	-	(4,193)	-	-	-
4101000	415935	Reg Liability - Contra - Carbon Decommis	WYP	(1,394)	-	-	-	(1,394)	-	-	-	-
4101000	415936	REG ASSET - CARBON PLANT DECOMMISS	SG	(183)	(3)	(49)	(14)	(25)	(82)	(10)	(0)	-
4101000	415943	Reg Asset - Covid-19 Bill Assistance Pro	OTHER	(15)	-	-	-	-	-	-	-	(15)
4101000	415944	Reg Asset - Covid-19 Bill Assistance Pro	OTHER		-	-	-	-	-	-	-	-
4101000	425100	190Deferred Regulatory Expense-IDU	IDU		-	-	-	-	-	-	-	-
4101000	425102	Reg Asset - CA GreenHouse Gas Allowance	OTHER		-	-	-	-	-	-	-	-
4101000	425103	Reg Asset - Other Regulatory Assets - Cu	OTHER		-	-	-	-	-	-	-	-
4101000	425104	Reg Asset - OR Asset Sale Gain Giveback	OTHER		-	-	-	-	-	-	-	-
4101000	425215	283Unearned Joint Use Pole Contact Revnu	SNPD	(26)	(2)	(7)	(2)	(2)	(13)	(1)	-	-
4101000	425225	Duke/Hermiston Contract Renegotiation	SG		-	-	-	-	-	-	-	-
4101000	425295	BPA Conservation Rate Credit	SG		-	-	-	-	-	-	-	-
4101000	425400	UT Kalamath Relicensing Costs	OTHER	(514)	-	-	-	-	-	-	-	(514)
4101000	430110	Reg Asset Balance Reclass	OTHER	515	-	-	-	-	-	-	-	515
4101000	430111	Reg Assets - SB 1149 Balance Reclass	OTHER		-	-	-	-	-	-	-	-
4101000	430112	Reg Asset - Other - Balance Reclass	OTHER	2,638	-	-	-	-	-	-	-	2,638
4101000	430113	Reg Asset - Def NPC Balance Reclass	OTHER		-	-	-	-	-	-	-	-
4101000	505510	190PMI Vacation/Bonus	SE	16	0	4	1	2	7	1	0	-
4101000	505600	190Vacation Sickleave & PT Accrual	SO		-	-	-	-	-	-	-	-
4101000	605101	Trojan Decommissioning Costs - WA	WA		-	-	-	-	-	-	-	-
4101000	605102	Trojan Decommissioning Costs - OR	OR		-	-	-	-	-	-	-	-
4101000	605103	ARO/Reg Diff - Trojan - WA	WA	(29)	-	-	(29)	-	-	-	-	-
4101000	610100	283PMI AMORT DEVELOPMENT	SE	(83)	(1)	(22)	(6)	(12)	(37)	(5)	(0)	-
4101000	6101001	190NOPA 103-99-00 RAR	SO	34	1	9	3	4	15	2	0	-
4101000	610111	283PMI SALE OF ASSETS	SE	853	11	225	58	127	381	51	0	-
4101000	610114	PMI EITF Pre stripping Cost	SE	998	13	263	68	148	446	60	0	-
4101000	610146	190OR Reg Asset/Liability Consol	OR	3	-	3	-	-	-	-	-	-
4101000	705200	190OR Gain on Sale of Halsey-OR	OTHER		-	-	-	-	-	-	-	-
4101000	705210	190Property Insurance	SO		-	-	-	-	-	-	-	-
4101000	705261	Reg Liability - Sale of Renewable Energy	OTHER	84	-	-	-	-	-	-	-	84
4101000	705265	Reg Liab - OR Energy Conservation Charge	OTHER	(222)	-	-	-	-	-	-	-	(222)
4101000	705300	Reg. Liability - Deferred Benefit_Arch S	SE		-	-	-	-	-	-	-	-

PACIFICORP

Deferred Income Tax Expense (Actuals)
Twelve Months Ending - June 2023
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
4101000	705305	Reg Liability-CA Gain on Sale of Asset	CA		-	-	-	-	-	-	-	-
4101000	705337	Reg Liability - Sale of Renewable Energy	OTHER	(98)	-	-	-	-	-	-	-	(98)
4101000	705454	Reg Liability - UT Property Insurance Re	UT	360	-	-	-	-	360	-	-	-
4101000	705534	Regulatory Liability - OR Asset Sale Gai	OTHER		-	-	-	-	-	-	-	-
4101000	705537	Regulatory Liability - Other Reg Liabili	OTHER		-	-	-	-	-	-	-	-
4101000	705700	Reg Liability - Current Reclass - Other	OTHER		-	-	-	-	-	-	-	-
4101000	705755	Reg Liability - Non current Reclass - Ot	OTHER	(12)	-	-	-	-	-	-	-	(12)
4101000	715295	Reg Liability - Fly Ash - OR	OTHER	(345)	-	-	-	-	-	-	-	(345)
4101000	715800	190Redding Contract	SG		-	-	-	-	-	-	-	-
4101000	720200	190Deferred Compensation Payout	SO	(41)	(1)	(11)	(3)	(5)	(18)	(2)	(0)	-
4101000	720300	190Pension/Retirement (Accrued/Prepaid)	SO		-	-	-	-	-	-	-	-
4101000	720500	190Severance	SO	(15)	(0)	(4)	(1)	(2)	(7)	(1)	(0)	-
4101000	720800	190FAS 158 Pension Liability	SO		-	-	-	-	-	-	-	-
4101000	720805	FAS 158 - Funded Pension Asset	SO	3,243	85	889	237	412	1,442	177	0	-
4101000	720810	190FAS 158 Post Retirement Liability	SO		-	-	-	-	-	-	-	-
4101000	720815	FAS 158 Post Retirement Liability	SO	284	7	78	21	36	126	15	0	-
4101000	910530	190Injuries & Damages	SO	(117,267)	(3,076)	(32,161)	(8,580)	(14,913)	(52,143)	(6,394)	(0)	-
4101000	910560	283SMUD Revenue Imputation-UT Reg Liab	OTHER		-	-	-	-	-	-	-	-
4101000 Total				**439,886**	**9,097**	**93,775**	**25,650**	**43,960**	**158,954**	**18,767**	**0**	**89,684**
4111000	100105	283FAS 109 Def Tax Liab WA-NUTIL	OTHER		-	-	-	-	-	-	-	-
4111000	105100	190CAPITALIZED LABOR COSTS	SO	(1,120)	(29)	(307)	(82)	(142)	(498)	(61)	(0)	-
4111000	105112	Non-Protected PP&E EDIT - UT	UT		-	-	-	-	-	-	-	-
4111000	1051151	Depreciation Flow-Through - CA	CA	(397)	(397)	-	-	-	-	-	-	-
4111000	10511510	Def In Tax Exp~Effects Ratemaking-Assets	SG	(7,610)	(105)	(2,046)	(570)	(1,048)	(3,415)	(426)	(0)	-
4111000	10511511	Def In Tax Exp~Effects Ratemaking-AssetS	SG	(34)	(0)	(9)	(3)	(5)	(15)	(2)	(0)	-
4111000	10511512	Def In Tax Exp~Effects Ratemaking-AssetS	SG	53	1	14	4	7	24	3	0	-
4111000	10511513	Def In Tax Exp~Effects Ratemaking-Assets	SO	(651)	(17)	(178)	(48)	(83)	(289)	(35)	(0)	-
4111000	1051152	Depreciation Flow-Through - FERC	FERC	(177)	-	-	-	-	-	-	(177)	-
4111000	1051153	Depreciation Flow-Through - ID	IDU	(295)	-	-	-	-	-	(295)	-	-
4111000	1051154	Depreciation Flow-Through - OR	OR	(2,358)	-	(2,358)	-	-	-	-	-	-
4111000	1051155	Depreciation Flow-Through - OTHER	OTHER	(19)	-	-	-	-	-	-	-	(19)
4111000	1051156	Depreciation Flow-Through - UT	UT	(945)	-	-	-	-	(945)	-	-	-
4111000	1051157	Depreciation Flow-Through - WA	WA	278	-	-	278	-	-	-	-	-
4111000	1051158	Depreciation Flow-Through - WYP	WYP	(1,001)	-	-	-	(1,001)	-	-	-	-
4111000	1051159	Depreciation Flow-Through - WYU	WYU	(742)	-	-	-	(742)	-	-	-	-
4111000	1051171	Protected PP&E EDIT - PMI - CA - Fed Onl	CA	0	0	-	-	-	-	-	-	-
4111000	1051172	Protected PP&E EDIT - PMI - UFERC - Fed	FERC	0	-	-	-	-	-	-	0	-
4111000	1051173	Protected PP&E EDIT - PMI - ID - Fed Onl	IDU	2	-	-	-	-	-	2	-	-
4111000	1051174	Protected PP&E EDIT - PMI - OR - Fed Onl	OR	7	-	7	-	-	-	-	-	-
4111000	1051175	Protected PP&E EDIT - PMI - UT - Fed Onl	UT	13	-	-	-	-	13	-	-	-
4111000	1051176	Protected PP&E EDIT - PMI - WA - Fed Onl	WA	7	-	-	7	-	-	-	-	-
4111000	1051177	Protected PP&E EDIT - PMI - WYP - Fed On	WYP	5	-	-	-	5	-	-	-	-
4111000	105120	Book Depreciation	SCHMDEXP	(267,107)	(6,599)	(71,618)	(19,782)	(34,936)	(119,516)	(14,656)	(0)	-

PACIFICORP

Deferred Income Tax Expense (Actuals)
Twelve Months Ending - June 2023
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
4111000	105121	282DIT PMIDepreciation-Book	SE	(1,539)	(20)	(405)	(105)	(229)	(688)	(93)	(0)	-
4111000	105123	Sec 481a Adj- Repair Deduction	SG		-	-	-	-	-	-	-	-
4111000	105130	CIAC	CIAC	(33,808)	(2,282)	(8,451)	(1,958)	(2,907)	(16,532)	(1,677)	-	-
4111000	105140	Highway Relocation	SNPD	(650)	(44)	(162)	(38)	(56)	(318)	(32)	-	-
4111000	105142	Avoided Costs	SNP	(22,296)	(633)	(5,827)	(1,567)	(2,797)	(10,244)	(1,227)	(0)	-
4111000	105146	Capitalization of Test Energy	SG		-	-	-	-	-	-	-	-
4111000	105220	282CHOLLA TAX LEASE	SG		-	-	-	-	-	-	-	-
4111000	105271	Def In Tax Exp - Other Property Flowthro	CA	(109)	(109)	-	-	-	-	-	-	-
4111000	105272	Def In Tax Exp - Other Property Flowthro	IDU	(63)	-	-	-	-	-	(63)	-	-
4111000	105273	Def In Tax Exp - Other Property Flowthro	OR	258	-	258	-	-	-	-	-	-
4111000	105274	Def In Tax Exp - Other Property Flowthro	UT	547	-	-	-	-	547	-	-	-
4111000	105275	Def In Tax Exp - Other Property Flowthro	WA	(305)	-	-	(305)	-	-	-	-	-
4111000	105276	Def In Tax Exp - Other Property Flowthro	WYP	(344)	-	-	-	(344)	-	-	-	-
4111000	105471	UT Kalamath Relicensing Costs	OTHER	7,888	-	-	-	-	-	-	-	7,888
4111000	110100	283BOOK COST DEPLETION ADDBACK	SE		-	-	-	-	-	-	-	-
4111000	205100	190COAL PILE INVENTORY	SE		-	-	-	-	-	-	-	-
4111000	205210	ERC (Emission Reduction Credit) Impairme	SE		-	-	-	-	-	-	-	-
4111000	210200	283Prepaid Taxes-Property Taxes	GPS	392	10	108	29	50	174	21	0	-
4111000	220100	190Bad Debt Allowance	BADDEBT	(1,348)	(40)	(525)	(364)	(69)	(325)	(25)	-	-
4111000	2874941	190Idaho ITC Credits	SO		-	-	-	-	-	-	-	-
4111000	320270	Reg Asset FAS 158 Pension Liab	SO	(8,402)	(220)	(2,304)	(615)	(1,069)	(3,736)	(458)	(0)	-
4111000	320280	Reg Asset FAS 158 Post Retire Liab	SO	2,125	56	583	155	270	945	116	0	-
4111000	320281	Reg Asset - Post-Retirement Settlement L	SO	(229)	(6)	(63)	(17)	(29)	(102)	(12)	(0)	-
4111000	320282	Reg Asset - Post-Retirement Settlement L	UT		-	-	-	-	-	-	-	-
4111000	320283	Reg Asset - Post-Retirement Settlement L	WYU		-	-	-	-	-	-	-	-
4111000	415115	Reg Asset - UT STEP Pilot Programs Balan	OTHER	1,161	-	-	-	-	-	-	-	1,161
4111000	415251	Reg Asset - Low Carbon Energy Standards	OTHER	(63)	-	-	-	-	-	-	-	(63)
4111000	415252	Reg Asset - Distribution System Plan - O	OTHER	368	-	-	-	-	-	-	-	368
4111000	415261	Reg Asset-UT Wildland Fire Protection	OTHER	2,463	-	-	-	-	-	-	-	2,463
4111000	415262	Reg Asset -Wildfire Mitigation Account -	OTHER	12,950	-	-	-	-	-	-	-	12,950
4111000	415263	Reg Asset - Wildfire Damaged Asset - OR	OR	34	-	34	-	-	-	-	-	-
4111000	415264	Reg Asset - TB Flats - OR	OTHER	1,694	-	-	-	-	-	-	-	1,694
4111000	415270	Reg Asset - Electric Vehicle Charging In	OTHER	(1,279)	-	-	-	-	-	-	-	(1,279)
4111000	415301	190Hazardous Waste/Environmental-WA	WA	(88)	-	-	(88)	-	-	-	-	-
4111000	415305	Reg Asset - Cedar Springs II - OR	OTHER	67	-	-	-	-	-	-	-	67
4111000	415406	Reg Asset Utah ECAM	OTHER		-	-	-	-	-	-	-	-
4111000	415423	Contra PP&E Deer Creek	SE		-	-	-	-	-	-	-	-
4111000	415424	Contra Reg Asset - Deer Creek Abandonmen	SE	(1,357)	(17)	(358)	(93)	(202)	(607)	(82)	(0)	-
4111000	415425	Contra Reg Asset - UMWA Pension	OTHER		-	-	-	-	-	-	-	-
4111000	415426	Reg Asset - 2020 GRC - Meters Replaced b	OTHER	(677)	-	-	-	-	-	-	-	(677)
4111000	415430	Reg Asset - CA - Transportation Electri	OTHER	(3)	-	-	-	-	-	-	-	(3)
4111000	415500	283Cholla Plt Trans-APS Amort	SGCT		-	-	-	-	-	-	-	-
4111000	415510	283WA DISALLOWED COLSTRIP #3 WRITE	WA		-	-	-	-	-	-	-	-

PACIFICORP

Deferred Income Tax Expense (Actuals)
Twelve Months Ending - June 2023
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
4111000	415645	RA - OR OCAT Expense Deferral	OTHER	(145)	-	-	-	-	-	-	-	(145)
4111000	415702	REG ASSET - LAKE SIDE LIQ - WY	WYP	(7)	-	-	-	(7)	-	-	-	-
4111000	415703	Goodnoe Hills Liquidation Damages - WY	WYP	(5)	-	-	-	(5)	-	-	-	-
4111000	415704	Reg Liability - Tax Revenue Adjustment -	UT		-	-	-	-	-	-	-	-
4111000	415705	Reg Liability - Tax Revenue Adjustment -	WYP		-	-	-	-	-	-	-	-
4111000	415710	Reg Liability - WA - Accelerated Depreci	WA	4,283	-	-	4,283	-	-	-	-	-
4111000	415723	Reg Asset - Cholla U4 - O&M Depreciation	IDU		-	-	-	-	-	-	-	-
4111000	415724	Deferred Income Tax Expense ~ Cholla U4	SG		-	-	-	-	-	-	-	-
4111000	415728	Contra Reg Asset - Cholla U4 Closure - O	OTHER	174	-	-	-	-	-	-	-	174
4111000	415729	Contra Reg Asset - Cholla U4 Closure - U	UT		-	-	-	-	-	-	-	-
4111000	415730	Contra Reg Asset - Cholla U4 Closure - W	WYP		-	-	-	-	-	-	-	-
4111000	415734	Reg Asset - Cholla Unrecovered Plant - C	CA	(59)	(59)	-	-	-	-	-	-	-
4111000	415736	Reg Asset - Cholla Unrecovered Plant - W	WYP	(937)	-	-	-	(937)	-	-	-	-
4111000	415803	RTO Grid West N/R Writeoff WA	WA		-	-	-	-	-	-	-	-
4111000	415804	RTO Grid West Notes Receivable-OR	OR		-	-	-	-	-	-	-	-
4111000	415806	RTO Grid West N/R Writeoff ID	IDU		-	-	-	-	-	-	-	-
4111000	415822	Reg Asset _ Pension MMT -UT	UT		-	-	-	-	-	-	-	-
4111000	415827	Reg Asset Post Retirement MMT - OR	OR		-	-	-	-	-	-	-	-
4111000	415828	Reg Asset Post Retirement MMT - WY	WYP		-	-	-	-	-	-	-	-
4111000	415829	Reg Asset - Post - Ret MMT -UT	UT		-	-	-	-	-	-	-	-
4111000	415831	Reg Asset Post Retirement MMT - CA	CA		-	-	-	-	-	-	-	-
4111000	415840	Reg Asset-Deferred OR Independent Evalua	OTHER	19	-	-	-	-	-	-	-	19
4111000	415841	Reg Asset - Emergency Service Programs -	OTHER	46	-	-	-	-	-	-	-	46
4111000	415842	Reg Asset-Arrearage Payment Program(CAPP	OTHER		-	-	-	-	-	-	-	-
4111000	415843	Reg Asset-Arrearage Payment Program(CAPP	OTHER		-	-	-	-	-	-	-	-
4111000	415852	Powerdale Decommissioning Reg Asset - ID	IDU		-	-	-	-	-	-	-	-
4111000	415853	Powerdale Decommissioning Reg Asset - OR	OR		-	-	-	-	-	-	-	-
4111000	415854	Powerdale Decommissioning Reg Asset - WA	WA		-	-	-	-	-	-	-	-
4111000	415855	CA - January 2010 Storm Costs	OTHER	(124)	-	-	-	-	-	-	-	(124)
4111000	415856	Powerdale Decommissioning Reg Asset - WY	WYP		-	-	-	-	-	-	-	-
4111000	415857	ID - Deferred Overburden Costs	OTHER	(22)	-	-	-	-	-	-	-	(22)
4111000	415858	WY - Deferred Overburden Costs	WYP	(62)	-	-	-	(62)	-	-	-	-
4111000	415859	WY - Deferred Advertising Costs	WYP		-	-	-	-	-	-	-	-
4111000	415865	Reg Asset - UT MPA	OTHER	0	-	-	-	-	-	-	-	0
4111000	415867	Reg Asset - CA Solar Feed-in Tariff	OTHER		-	-	-	-	-	-	-	-
4111000	415868	Reg Asset - UT - Solar Incentive Program	OTHER	(1,047)	-	-	-	-	-	-	-	(1,047)
4111000	415876	Deferred Excess Net PowerCosts - OR	OTHER	29,457	-	-	-	-	-	-	-	29,457
4111000	415881	Deferral of Renewable Energy Credit - UT	OTHER		-	-	-	-	-	-	-	-
4111000	415883	Deferral of Renewable Energy Credit - WY	OTHER		-	-	-	-	-	-	-	-
4111000	415890	ID MEHC 2006 Transition Costs	IDU		-	-	-	-	-	-	-	-
4111000	415891	WY - 2006 Transition Severance Costs	WYP		-	-	-	-	-	-	-	-
4111000	415893	OR - MEHC Transition Service Costs	OTHER		-	-	-	-	-	-	-	-
4111000	415895	OR_RCAC SEP-DEC 07 DEFERRED	OR		-	-	-	-	-	-	-	-

PACIFICORP

Deferred Income Tax Expense (Actuals)
Twelve Months Ending - June 2023
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
4111000	415896	WA - Chehalis Plant Revenue Requirement	WA		-	-	-	-	-	-	-	-
4111000	415897	Reg Asset MEHC Transition Service Costs	CA		-	-	-	-	-	-	-	-
4111000	415898	Deferred Coal Costs - Naughton Contract	SE		-	-	-	-	-	-	-	-
4111000	415902	Reg Asset - UT REC's in Rates - Current	OTHER		-	-	-	-	-	-	-	-
4111000	415911	Contra Reg Asset - Naughton Unit $3 - CA	CA		-	-	-	-	-	-	-	-
4111000	415912	Contra Reg Asset - Naughton Unit #3 - OR	OTHER		-	-	-	-	-	-	-	-
4111000	415913	Contra Reg Asset - Naughton Unit #3 - WA	OTHER		-	-	-	-	-	-	-	-
4111000	415914	Reg Asset - UT - Naughton U3 Costs	UT		-	-	-	-	-	-	-	-
4111000	415915	Reg Asset - WY - Naughton U3 Costs	WYP		-	-	-	-	-	-	-	-
4111000	415926	Reg Liability - Depreciation Decrease -	OTHER	668	-	-	-	-	-	-	-	668
4111000	415927	Reg Liability - Depreciation Decrease De	WA		-	-	-	-	-	-	-	-
4111000	415938	Reg Asset - Carbon Plant Decommissioning	CA	13	13	-	-	-	-	-	-	-
4111000	415939	Reg Asset - Carbon Plant Decommissioning	WYP		-	-	-	-	-	-	-	-
4111000	415942	Reg Liability - Steam Decommissioning -	WA	(878)	-	-	(878)	-	-	-	-	-
4111000	425105	Reg Asset - OR Asset Sale Gain Giveback	OTHER	211	-	-	-	-	-	-	-	211
4111000	425125	Deferred Coal Cost - Arch	SE		-	-	-	-	-	-	-	-
4111000	425215	283Unearned Joint Use Pole Contact Revnu	SNPD		-	-	-	-	-	-	-	-
4111000	425250	283TGS BUYOUT-SG	SG		-	-	-	-	-	-	-	-
4111000	425280	283JOSEPH SETTLEMENT-SG	SG		-	-	-	-	-	-	-	-
4111000	425360	190Hermiston Swap	SG	(42)	(1)	(11)	(3)	(6)	(19)	(2)	(0)	-
4111000	425380	190Idaho Customer Bal Acct	OTHER	256	-	-	-	-	-	-	-	256
4111000	430100	283Weatherization	OTHER	2,975	-	-	-	-	-	-	-	2,975
4111000	430117	Reg Asset - Current DSM	OTHER		-	-	-	-	-	-	-	-
4111000	505115	283Sales & Use Tax Audit	SO		-	-	-	-	-	-	-	-
4111000	505125	190Accrued Royalties	SE	(147)	(2)	(39)	(10)	(22)	(66)	(9)	(0)	-
4111000	505400	190Bonus Liability	SO	87	2	24	6	11	39	5	0	-
4111000	505450	Accrued Payroll Taxes	SO	3,086	81	846	226	392	1,372	168	0	-
4111000	5054501	Accrued Payroll Taxes - PMI	SE	124	2	33	8	18	55	7	0	-
4111000	505520	Bonus Accrual - PMI	SE	(9)	(0)	(2)	(1)	(1)	(4)	(1)	(0)	-
4111000	505525	Accrued Severance -PMI	SE	15	0	4	1	2	7	1	0	-
4111000	505600	190Vacation Sickleave & PT Accrual	SO	(683)	(18)	(187)	(50)	(87)	(304)	(37)	(0)	-
4111000	505601	Sick Leave Accrual - PMI	SE	3	0	1	0	1	2	0	0	-
4111000	505700	190Accrued Retention Bonus	SO	3	0	1	0	0	1	0	0	-
4111000	605100	283TROJAN DECOMMISSIONING AMORT	TROJD	91	1	24	7	13	41	5	0	-
4111000	605710	REVERSE ACCRUED FINAL RECLAMATION	OTHER	75	-	-	-	-	-	-	-	75
4111000	605715	Trapper Mine Contract Obligation	SE	(553)	(7)	(146)	(38)	(82)	(247)	(33)	(0)	-
4111000	610000	283PMI Development Costs	SE		-	-	-	-	-	-	-	-
4111000	610141	190WA Rate Refunds	OTHER	700	-	-	-	-	-	-	-	700
4111000	610144	Reg Liability - CA California Alternativ	OTHER		-	-	-	-	-	-	-	-
4111000	610145	190REG LIAB_DSM	OTHER	(515)	-	-	-	-	-	-	-	(515)
4111000	610148	Reg Liability - Def NPC Balance Reclass	OTHER		-	-	-	-	-	-	-	-
4111000	610150	REG LIABILITY - BRIDGER MINE ACCELERA	OR	(894)	-	(894)	-	-	-	-	-	-
4111000	610155	Reg Liability - Plant Closure Cost - WA	WA	(333)	-	-	(333)	-	-	-	-	-

PACIFICORP

Deferred Income Tax Expense (Actuals)
Twelve Months Ending - June 2023
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
4111000	705240	283CA Alternative Rate for Energy Progra	OTHER	111	-	-	-	-	-	-	-	111
4111000	705241	Reg Liability - CA California Alternativ	OTHER	47	-	-	-	-	-	-	-	47
4111000	705245	REG LIABILITY - OR DIRECT ACCESS 5 YEA	OTHER	398	-	-	-	-	-	-	-	398
4111000	705262	Reg Liability - Sale of REC's-ID	OTHER		-	-	-	-	-	-	-	-
4111000	705263	Reg Liability - Sale of REC's-WA	OTHER	(19)	-	-	-	-	-	-	-	(19)
4111000	705266	Reg Liability - Energy Savings Assistanc	OTHER	62	-	-	-	-	-	-	-	62
4111000	705267	Reg Liability - WA Decoupling Mechanism	OTHER	(1,481)	-	-	-	-	-	-	-	(1,481)
4111000	705280	Non-Property EDIT - CA	CA	(225)	(225)	-	-	-	-	-	-	-
4111000	705281	Non-Property EDIT - ID	IDU		-	-	-	-	-	-	-	-
4111000	705283	Non-Property EDIT - UT	UT		-	-	-	-	-	-	-	-
4111000	705284	Non-Property EDIT - WA	WA	(211)	-	-	(211)	-	-	-	-	-
4111000	705285	Non-Property EDIT - WY	WYU		-	-	-	-	-	-	-	-
4111000	705286	Non-Property EDIT - FERC	FERC		-	-	-	-	-	-	-	-
4111000	705287	Protected PP&E EDIT - CA - Fed Only	CA	(1,094)	(1,094)	-	-	-	-	-	-	-
4111000	705288	Protected PP&E EDIT - ID - Fed Only	IDU	(2,951)	-	-	-	-	-	(2,951)	-	-
4111000	705289	Protected PP&E EDIT - OR - Fed Only	OR	(13,796)	-	(13,796)	-	-	-	-	-	-
4111000	705290	Protected PP&E EDIT - WA - Fed Only	WA	(6,621)	-	-	(6,621)	-	-	-	-	-
4111000	705291	Protected PP&E EDIT - WYP - Fed Only	WYP	(7,813)	-	-	-	(7,813)	-	-	-	-
4111000	7052911	Protected PP&E EDIT - WYU - Fed Only	WYU		-	-	-	-	-	-	-	-
4111000	705292	Protected PP&E EDIT - UT - Fed Only	UT	(22,173)	-	-	-	-	(22,173)	-	-	-
4111000	705293	Protected PP&E EDIT - UFERC - Fed Only	FERC		-	-	-	-	-	-	-	-
4111000	705294	Non-Protected PP&E EDIT - CA	CA	(854)	(854)	-	-	-	-	-	-	-
4111000	705295	Non-Protected PP&E EDIT - ID	IDU		-	-	-	-	-	-	-	-
4111000	705296	Non-Protected PP&E EDIT - WA	WA	(4,175)	-	-	(4,175)	-	-	-	-	-
4111000	705297	Non-Protected PP&E EDIT - WY Buydown - C	WYP	(11,173)	-	-	-	(11,173)	-	-	-	-
4111000	705298	Non-Protected PP&E EDIT - Utah Buydown -	UT		-	-	-	-	-	-	-	-
4111000	705299	Non-Protected PP&E EDIT - FERC	FERC		-	-	-	-	-	-	-	-
4111000	705301	Reg Liability - OR 2010 Protocol Def	OR		-	-	-	-	-	-	-	-
4111000	705336	Reg Liability - Sale of Renewable Energy	OTHER	(225)	-	-	-	-	-	-	-	(225)
4111000	705340	Reg Liability - Excess Income Tax Deferr	OTHER	383	-	-	-	-	-	-	-	383
4111000	705341	Reg Liability - Excess Income Tax Deferr	OTHER		-	-	-	-	-	-	-	-
4111000	705342	Reg Liability - Excess Income Tax Deferr	OTHER	816	-	-	-	-	-	-	-	816
4111000	705343	Reg Liability - Excess Income Tax Deferr	OTHER		-	-	-	-	-	-	-	-
4111000	705344	Reg Liability - Excess Income Tax Deferr	OTHER	373	-	-	-	-	-	-	-	373
4111000	705345	Reg Liability - Excess Income Tax Deferr	OTHER	(5)	-	-	-	-	-	-	-	(5)
4111000	705346	Deferral of Protected PP&E ARAM - CA	CA	(710)	(710)	-	-	-	-	-	-	-
4111000	705347	Deferral of Protected PP&E ARAM - ID	IDU	(3,373)	-	-	-	-	-	(3,373)	-	-
4111000	705348	Deferral of Protected PP&E ARAM - OR	OR		-	-	-	-	-	-	-	-
4111000	705349	Deferral of Protected PP&E ARAM - UT	UT	(13,615)	-	-	-	-	(13,615)	-	-	-
4111000	705350	Deferral of Protected PP&E ARAM - WA	WA	(2,543)	-	-	(2,543)	-	-	-	-	-
4111000	705351	Deferral of Protected PP&E ARAM - WY	WYU	(10,972)	-	-	-	(10,972)	-	-	-	-
4111000	705352	Reg Liability - CA Klamath River Dams Re	CA	(0)	(0)	-	-	-	-	-	-	-
4111000	705400	Reg Liability - OR Injuries & Damages Re	OR	2,188	-	2,188	-	-	-	-	-	-

PACIFICORP

Deferred Income Tax Expense (Actuals)
Twelve Months Ending - June 2023
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
4111000	705410	Reg Liability - Cholla Decommissioning -	CA	9	9	-	-	-	-	-	-	-
4111000	705411	Reg Liability - Cholla Decommissioning -	IDU	35	-	-	-	-	-	35	-	-
4111000	705412	Reg Liability - Cholla Decommissioning -	OR	152	-	152	-	-	-	-	-	-
4111000	705413	Reg Liability - Cholla Decommissioning -	UT	257	-	-	-	-	257	-	-	-
4111000	705414	Reg Liability - Cholla Decommissioning -	WYP	(66)	-	-	-	(66)	-	-	-	-
4111000	705420	Reg Liability - CA GHG Allowance Revenue	OTHER	(1,700)	-	-	-	-	-	-	-	(1,700)
4111000	705425	Reg Liability - Bridger Mine Accelerated	WA	(627)	-	-	(627)	-	-	-	-	-
4111000	705450	Reg Liability - Property Insurance Reser	CA	1,136	1,136	-	-	-	-	-	-	-
4111000	705451	Reg Liability - OR Property Insurance Re	OR	1,350	-	1,350	-	-	-	-	-	-
4111000	705452	Reg Liability - Property Insurance Reser	WA	76	-	-	76	-	-	-	-	-
4111000	705453	Reg Liability - ID Property Insurance Re	IDU		-	-	-	-	-	-	-	-
4111000	705455	Reg Liability - WY Property Insurance Re	WYP	92	-	-	-	92	-	-	-	-
4111000	705500	Reg Liability - Powerdale Decommissionin	UT		-	-	-	-	-	-	-	-
4111000	705511	Regulatory Liability - CA Deferred Exces	OTHER	(397)	-	-	-	-	-	-	-	(397)
4111000	705514	Regulatory Liability - OR Deferred Exces	OTHER		-	-	-	-	-	-	-	-
4111000	705515	Regulatory Liability - OR Deferred Exces	OTHER	976	-	-	-	-	-	-	-	976
4111000	705517	Regulatory Liability - UT Deferred Exces	OTHER		-	-	-	-	-	-	-	-
4111000	705518	Regulatory Liability - WA Deferred Exces	OTHER		-	-	-	-	-	-	-	-
4111000	705519	Regulatory Liability - WA Deferred Exces	OTHER		-	-	-	-	-	-	-	-
4111000	705521	Regulatory Liability - WY Deferred Exces	OTHER		-	-	-	-	-	-	-	-
4111000	705522	Regulatory Liability - UT RECS in Rates	OTHER		-	-	-	-	-	-	-	-
4111000	705523	Regulatory Liability - WA RECS in Rates	OTHER		-	-	-	-	-	-	-	-
4111000	705525	REGULATORY LIABILITY - SALE OF REC - (	OTHER		-	-	-	-	-	-	-	-
4111000	705526	Regulatory Liability - CA Solar Feed-in	OTHER		-	-	-	-	-	-	-	-
4111000	705527	Regulatory Liability - CA Solar Feed-in	OTHER		-	-	-	-	-	-	-	-
4111000	705530	Regulatory Liability - UT Solar Feed-in	OTHER		-	-	-	-	-	-	-	-
4111000	705531	Regulatory Liability - UT Solar Feed-in	OTHER	1,252	-	-	-	-	-	-	-	1,252
4111000	705536	Regulatory Liability - CA GreenHouse Gas	OTHER		-	-	-	-	-	-	-	-
4111000	705600	RegLiability - OR 2012 GRC Giveback	OTHER		-	-	-	-	-	-	-	-
4111000	705700	Reg Liability - Current Reclass - Other	OTHER		-	-	-	-	-	-	-	-
4111000	715105	MCI FOG Wire Lease	SG	424	6	114	32	58	190	24	0	-
4111000	715720	190NW Power Act(BPA Regional Crs)-WA	OTHER	30	-	-	-	-	-	-	-	30
4111000	715810	Chehalis WA EFSEC C02 Mitigation Obligat	SG		-	-	-	-	-	-	-	-
4111000	720300	190Pension/Retirement (Accrued/Prepaid)	SO	53	1	15	4	7	24	3	0	-
4111000	720560	Pension Liability - UMWA Withdrawal Obli	SE		-	-	-	-	-	-	-	-
4111000	740100	283Post Merger Debt Loss	SNP	(99)	(3)	(26)	(7)	(12)	(46)	(5)	(0)	-
4111000	910245	Contra Receivable from Joint Owners	SO	36	1	10	3	5	16	2	0	-
4111000	910905	283PMI BCC Underground Mine Cost Deplet	SE	20	0	5	1	3	9	1	0	-
4111000	920110	190PMIWYExtractionTax	SE	785	10	207	54	117	351	47	0	-
4111000	930100	190OR BETC Credit	OTHER		-	-	-	-	-	-	-	-
4111000	9301001	190OR BETC Credit	SG		-	-	-	-	-	-	-	-
4111000	999998	Deferred Income Tax Expense ~ Solar ITC	SG	20	0	5	1	3	9	1	0	-
4111000 Total				**(384,714)**	**(12,163)**	**(103,731)**	**(35,955)**	**(75,849)**	**(189,627)**	**(25,114)**	**(177)**	**57,902**

Deferred Income Tax Expense (Actuals)
Twelve Months Ending - June 2023
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
Grand Total				**55,172**	**(3,066)**	**(9,956)**	**(10,305)**	**(31,889)**	**(30,674)**	**(6,347)**	**(177)**	**147,586**

Investment Tax Credit Amortization (Actuals)
Sum of Range: 07/2022 - 06/2023
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
4114000	DEF ITC-EL-FED-CR	0	DEF ITC CREDIT FED	DGU	(910)	-	-	-	(30)	(783)	(98)	(0)	-
4114000 Total					**(910)**	**-**	**-**	**-**	**(30)**	**(783)**	**(98)**	**(0)**	**-**
Grand Total					**(910)**	**-**	**-**	**-**	**(30)**	**(783)**	**(98)**	**(0)**	**-**

B8. PLANT IN SERVICE

PACIFICORP

Electric Plant in Service (Actuals)
Year End: 06/2023
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	13,121	181	3,527	983	1,808	5,889	734	0	-
1010000	ELEC PLANT IN SERV	3020000	FRANCHISES AND CONSENTS	SG-P	103,455	1,424	27,813	7,747	14,252	46,431	5,788	0	-
1010000	ELEC PLANT IN SERV	3020000	FRANCHISES AND CONSENTS	SG-U	10,502	145	2,823	786	1,447	4,713	587	0	-
1010000	ELEC PLANT IN SERV	3031040	TRANSMISSION INTANGIBLE ASSETS	OR	531	-	531	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3031040	TRANSMISSION INTANGIBLE ASSETS	SG	53,615	738	14,414	4,015	7,386	24,063	2,999	0	-
1010000	ELEC PLANT IN SERV	3031040	TRANSMISSION INTANGIBLE ASSETS	UT	3,231	-	-	-	-	3,231	-	-	-
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	295	3,085	823	1,431	5,002	613	0	-
1010000	ELEC PLANT IN SERV	3031080	FUEL MANAGEMENT SYSTEM	SO	3,293	86	903	241	419	1,464	180	0	-
1010000	ELEC PLANT IN SERV	3031230	AFPR - AUTOMATED FACILITY POINT RECORDS	SO	4,410	116	1,209	323	561	1,961	240	0	-
1010000	ELEC PLANT IN SERV	3031680	CADOPS - COMPUTER-ASSISTED DISTRIBUTION	SO	16,796	441	4,606	1,229	2,136	7,468	916	0	-
1010000	ELEC PLANT IN SERV	3031830	CUSTOMER SERVICE SYSTEM (CSS)	CN	148,206	3,356	45,508	9,917	10,521	72,613	6,291	-	-
1010000	ELEC PLANT IN SERV	3032040	S A P	SO	183,239	4,807	50,254	13,406	23,303	81,477	9,991	0	-
1010000	ELEC PLANT IN SERV	3032130	NODAL PRICING SOFTWARE	SG	3,281	45	882	246	452	1,473	184	0	-
1010000	ELEC PLANT IN SERV	3032140	ESM-IRP	SO	3,649	96	1,001	267	464	1,623	199	0	-
1010000	ELEC PLANT IN SERV	3032150	CELONIS	SO	4,359	114	1,196	319	554	1,938	238	0	-
1010000	ELEC PLANT IN SERV	3032160	ARCOS	SO	3,083	81	845	226	392	1,371	168	0	-
1010000	ELEC PLANT IN SERV	3032170	AZURE B2C - IDENTITY MGT	SO	1,429	37	392	105	182	635	78	0	-
1010000	ELEC PLANT IN SERV	3032180	IAM - SCHEDULING/TAGGING SYSTEM	SO	1,342	35	368	98	171	597	73	0	-
1010000	ELEC PLANT IN SERV	3032190	PCI GenTrader	SO	1,888	50	518	138	240	839	103	0	-
1010000	ELEC PLANT IN SERV	3032200	ITOA	SO	4,360	114	1,196	319	555	1,939	238	0	-
1010000	ELEC PLANT IN SERV	3032210	TSSA - TrueSight Server Automation	SO	1,390	36	381	102	177	618	76	0	-
1010000	ELEC PLANT IN SERV	3032270	ENTERPRISE DATA WAREHOUSE	SO	5,877	154	1,612	430	747	2,613	320	0	-
1010000	ELEC PLANT IN SERV	3032330	FIELDNET PRO METER READING SYST -HRP REP	SO	2,908	76	797	213	370	1,293	159	0	-
1010000	ELEC PLANT IN SERV	3032340	FACILITY INSPECTION REPORTING SYSTEM	SO	2,020	53	554	148	257	898	110	0	-
1010000	ELEC PLANT IN SERV	3032360	2002 GRID NET POWER COST MODELING	SO	8,999	236	2,468	658	1,144	4,001	491	0	-
1010000	ELEC PLANT IN SERV	3032450	MID OFFICE IMPROVEMENT PROJECT	SO	10,577	277	2,901	774	1,345	4,703	577	0	-
1010000	ELEC PLANT IN SERV	3032510	OPERATIONS MAPPING SYSTEM	SO	10,386	272	2,849	760	1,321	4,618	566	0	-
1010000	ELEC PLANT IN SERV	3032530	POLE ATTACHMENT MGMT SYSTEM	SO	1,915	50	525	140	244	852	104	0	-
1010000	ELEC PLANT IN SERV	3032590	SUBSTATION/CIRCUIT HISTORY OF OPERATIONS	SO	2,416	63	663	177	307	1,074	132	0	-
1010000	ELEC PLANT IN SERV	3032600	SINGLE PERSON SCHEDULING	SO	13,486	354	3,699	987	1,715	5,997	735	0	-
1010000	ELEC PLANT IN SERV	3032640	TIBCO SOFTWARE	SO	7,830	205	2,147	573	996	3,481	427	0	-
1010000	ELEC PLANT IN SERV	3032680	TRANSMISSION WHOLESALE BILLING SYSTEM	SG	1,600	22	430	120	220	718	89	0	-
1010000	ELEC PLANT IN SERV	3032690	UTILITY INTERNATIONAL FORECASTING MODEL	SO	8,040	211	2,205	588	1,022	3,575	438	0	-
1010000	ELEC PLANT IN SERV	3032710	ROUGE RIVER HYDRO INTANGIBLES	SG	207	3	56	15	28	93	12	0	-
1010000	ELEC PLANT IN SERV	3032740	GADSBY INTANGIBLE ASSETS	SG	51	1	14	4	7	23	3	0	-
1010000	ELEC PLANT IN SERV	3032760	SWIFT 2 IMPROVEMENTS	SG	23,200	319	6,237	1,737	3,196	10,412	1,298	0	-
1010000	ELEC PLANT IN SERV	3032770	NORTH UMPQUA - SETTLEMENT AGREEMENT	SG	652	9	175	49	90	293	36	0	-
1010000	ELEC PLANT IN SERV	3032780	BEAR RIVER-SETTLEMENT AGREEMENT	SG	117	2	32	9	16	53	7	0	-
1010000	ELEC PLANT IN SERV	3032830	VCPRO - XEROX CUST STMT FRMTR ENHANCE -	SO	2,629	69	721	192	334	1,169	143	0	-
1010000	ELEC PLANT IN SERV	3032860	WEB SOFTWARE	SO	12,006	315	3,293	878	1,527	5,339	655	0	-
1010000	ELEC PLANT IN SERV	3032900	IDAHO TRANSMISSION CUSTOMER-OWNED ASSETS	SG	8,774	121	2,359	657	1,209	3,938	491	0	-
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	184	1,924	513	892	3,119	382	0	-
1010000	ELEC PLANT IN SERV	3033090	STEAM PLANT INTANGIBLE ASSETS	SG	89,672	1,235	24,108	6,715	12,353	40,245	5,016	0	-
1010000	ELEC PLANT IN SERV	3033190	ITRON METER READING SOFTWARE	CN	5,868	133	1,802	393	417	2,875	249	-	-
1010000	ELEC PLANT IN SERV	3033210	ArcFM Software	SO	3,978	104	1,091	291	506	1,769	217	0	-
1010000	ELEC PLANT IN SERV	3033220	MONARCH EMS/SCADA	SO	35,089	921	9,623	2,567	4,462	15,602	1,913	0	-
1010000	ELEC PLANT IN SERV	3033240	IEE - Itron Enterprise Addition	CN	4,934	112	1,515	330	350	2,418	209	-	-

PACIFICORP

Electric Plant in Service (Actuals)
Year End: 06/2023
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	3033250	AMI Metering Software	CN	48,604	1,101	14,924	3,252	3,450	23,813	2,063	-	-
1010000	ELEC PLANT IN SERV	3033260	Big Data & Analytics	SO	5,978	157	1,640	437	760	2,658	326	0	-
1010000	ELEC PLANT IN SERV	3033270	CES - Customer Experience System	CN	10,516	238	3,229	704	746	5,152	446	-	-
1010000	ELEC PLANT IN SERV	3033280	MAPAPPS - Mapping Systems Application	SO	7,595	199	2,083	556	966	3,377	414	0	-
1010000	ELEC PLANT IN SERV	3033290	CUSTOMER CONTACTS	CN	3,903	88	1,198	261	277	1,912	166	-	-
1010000	ELEC PLANT IN SERV	3033300	SECID - CUST SECURE WEB LOGIN	CN	1,085	25	333	73	77	532	46	-	-
1010000	ELEC PLANT IN SERV	3033310	C&T - Energy Trading System	SO	19,936	523	5,468	1,459	2,535	8,865	1,087	0	-
1010000	ELEC PLANT IN SERV	3033320	CAS - CONTROL AREA SCHEDULING (TRANSM)	SG	10,131	139	2,724	759	1,396	4,547	567	0	-
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	3033380	GAS PLANT INTANGIBLES	SG	1,601	22	430	120	221	719	90	0	-
1010000	ELEC PLANT IN SERV	3033390	CYME GATEWAY	SO	923	24	253	68	117	411	50	0	-
1010000	ELEC PLANT IN SERV	3033410	M365	SO	3,712	97	1,018	272	472	1,651	202	0	-
1010000	ELEC PLANT IN SERV	3033420	SUBSTATION RELIABILITY SOFTWARE	SO	825	22	226	60	105	367	45	0	-
1010000	ELEC PLANT IN SERV	3033430	DEPLOY DISTRIBUTION MGMT SYSTEM	SO	1,803	47	494	132	229	802	98	0	-
1010000	ELEC PLANT IN SERV	3033440	DISTRIBUTION ENGINEERING COSTS	SO	1,169	31	321	86	149	520	64	0	-
1010000	ELEC PLANT IN SERV	3033450	MAXIMO	SO	19,864	521	5,448	1,453	2,526	8,833	1,083	0	-
1010000	ELEC PLANT IN SERV	3033460	AURORA	SO	1,904	50	522	139	242	847	104	0	-
1010000	ELEC PLANT IN SERV	3033470	AUGMENTED REALITY	SO	3,046	80	835	223	387	1,354	166	0	-
1010000	ELEC PLANT IN SERV	3033480	CXP	CN	4,691	106	1,440	314	333	2,298	199	-	-
1010000	ELEC PLANT IN SERV	3033490	VMWARE	SO	7,308	192	2,004	535	929	3,250	398	0	-
1010000	ELEC PLANT IN SERV	3034900	MISC - MISCELLANEOUS	OR	12	-	12	-	-	-	-	-	-
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	197	3	53	15	27	88	11	0	-
1010000	ELEC PLANT IN SERV	3034900	MISC - MISCELLANEOUS	SO	38,100	1,000	10,449	2,788	4,845	16,941	2,077	0	-
1010000	ELEC PLANT IN SERV	3034900	MISC - MISCELLANEOUS	UT	7	-	-	-	-	7	-	-	-
1010000	ELEC PLANT IN SERV	3034900	MISC - MISCELLANEOUS	WA	1	-	-	1	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3034900	MISC - MISCELLANEOUS	WYP	81	-	-	-	81	-	-	-	-
1010000	ELEC PLANT IN SERV	3035320	HYDRO PLANT INTANGIBLES	SG	1,687	23	453	126	232	757	94	0	-
1010000	ELEC PLANT IN SERV	3035322	ACD–Call Center Automated Call Distribut	CN	4,132	94	1,269	277	293	2,025	175	-	-
1010000	ELEC PLANT IN SERV	3035330	OATI-OASIS INTERFACE	SO	1,447	38	397	106	184	643	79	0	-
1010000	ELEC PLANT IN SERV	3100000	LAND & LAND RIGHTS	SG	1,306	18	351	98	180	586	73	0	-
1010000	ELEC PLANT IN SERV	3101000	LAND OWNED IN FEE	SG	12,945	178	3,480	969	1,783	5,810	724	0	-
1010000	ELEC PLANT IN SERV	3102000	LAND RIGHTS	SG	41,789	575	11,235	3,129	5,757	18,755	2,338	0	-
1010000	ELEC PLANT IN SERV	3103000	WATER RIGHTS	SG	35,638	491	9,581	2,669	4,910	15,994	1,994	0	-
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	1,008,055	13,880	271,007	75,485	138,872	452,418	56,393	0	-
1010000	ELEC PLANT IN SERV	3120000	BOILER PLANT EQUIPMENT	SG	4,445,174	61,204	1,195,048	332,865	612,375	1,995,008	248,674	0	-
1010000	ELEC PLANT IN SERV	3140000	TURBOGENERATOR UNITS	SG	993,434	13,678	267,076	74,391	136,857	445,856	55,575	0	-
1010000	ELEC PLANT IN SERV	3150000	ACCESSORY ELECTRIC EQUIPMENT	SG	428,487	5,900	115,195	32,086	59,029	192,306	23,971	0	-
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	33,968	468	9,132	2,544	4,680	15,245	1,900	0	-
1010000	ELEC PLANT IN SERV	3300000	LAND AND LAND RIGHTS	SG-U	172	2	46	13	24	77	10	0	-
1010000	ELEC PLANT IN SERV	3301000	LAND OWNED IN FEE	SG-P	23,142	319	6,222	1,733	3,188	10,386	1,295	0	-
1010000	ELEC PLANT IN SERV	3301000	LAND OWNED IN FEE	SG-U	5,777	80	1,553	433	796	2,593	323	0	-
1010000	ELEC PLANT IN SERV	3302000	LAND RIGHTS	SG-P	7,994	110	2,149	599	1,101	3,588	447	0	-
1010000	ELEC PLANT IN SERV	3302000	LAND RIGHTS	SG-U	381	5	102	29	53	171	21	0	-
1010000	ELEC PLANT IN SERV	3303000	WATER RIGHTS	SG-P	21	0	6	2	3	9	1	0	-
1010000	ELEC PLANT IN SERV	3303000	WATER RIGHTS	SG-U	140	2	38	10	19	63	8	0	-
1010000	ELEC PLANT IN SERV	3304000	FLOOD RIGHTS	SG-P	406	6	109	30	56	182	23	0	-
1010000	ELEC PLANT IN SERV	3304000	FLOOD RIGHTS	SG-U	129	2	35	10	18	58	7	0	-

PACIFICORP

Electric Plant in Service (Actuals)
Year End: 06/2023
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	3305000	LAND RIGHTS - FISH/WILDLIFE	SG-P	310	4	83	23	43	139	17	0	-
1010000	ELEC PLANT IN SERV	3310000	STRUCTURES AND IMPROVE	SG-P	7	0	2	1	1	3	0	0	-
1010000	ELEC PLANT IN SERV	3310000	STRUCTURES AND IMPROVE	SG-U	9,355	129	2,515	701	1,289	4,199	523	0	-
1010000	ELEC PLANT IN SERV	3311000	STRUCTURES AND IMPROVE-PRODUCTION	SG-P	66,990	922	18,010	5,016	9,229	30,065	3,748	0	-
1010000	ELEC PLANT IN SERV	3311000	STRUCTURES AND IMPROVE-PRODUCTION	SG-U	10,346	142	2,782	775	1,425	4,643	579	0	-
1010000	ELEC PLANT IN SERV	3312000	STRUCTURES AND IMPROVE-FISH/WILDLIFE	SG-P	155,714	2,144	41,862	11,660	21,451	69,885	8,711	0	-
1010000	ELEC PLANT IN SERV	3312000	STRUCTURES AND IMPROVE-FISH/WILDLIFE	SG-U	364	5	98	27	50	163	20	0	-
1010000	ELEC PLANT IN SERV	3313000	STRUCTURES AND IMPROVE-RECREATION	SG-P	23,060	318	6,199	1,727	3,177	10,349	1,290	0	-
1010000	ELEC PLANT IN SERV	3313000	STRUCTURES AND IMPROVE-RECREATION	SG-U	2,056	28	553	154	283	923	115	0	-
1010000	ELEC PLANT IN SERV	3316000	STRUCTURES - LEASE IMPROVEMENTS	SG-P	14,768	203	3,970	1,106	2,034	6,628	826	0	-
1010000	ELEC PLANT IN SERV	3320000	"RESERVOIRS, DAMS & WATERWAYS"	SG-P	8,991	124	2,417	673	1,239	4,035	503	0	-
1010000	ELEC PLANT IN SERV	3320000	"RESERVOIRS, DAMS & WATERWAYS"	SG-U	30,858	425	8,296	2,311	4,251	13,849	1,726	0	-
1010000	ELEC PLANT IN SERV	3321000	"RESERVOIRS, DAMS, & WTRWYS-PRODUCTION"	SG-P	379,657	5,227	102,068	28,430	52,302	170,391	21,239	0	-
1010000	ELEC PLANT IN SERV	3321000	"RESERVOIRS, DAMS, & WTRWYS-PRODUCTION"	SG-U	74,814	1,030	20,113	5,602	10,307	33,577	4,185	0	-
1010000	ELEC PLANT IN SERV	3322000	"RESERVOIRS, DAMS, & WTRWYS-FISH/WILDLIF	SG-P	19,398	267	5,215	1,453	2,672	8,706	1,085	0	-
1010000	ELEC PLANT IN SERV	3322000	"RESERVOIRS, DAMS, & WTRWYS-FISH/WILDLIF	SG-U	411	6	110	31	57	184	23	0	-
1010000	ELEC PLANT IN SERV	3323000	"RESERVOIRS, DAMS, & WTRWYS-RECREATION"	SG-P	188	3	51	14	26	85	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	79,299	1,092	21,319	5,938	10,924	35,590	4,436	0	-
1010000	ELEC PLANT IN SERV	3330000	"WATER WHEELS, TURB & GENERATORS"	SG-U	51,285	706	13,787	3,840	7,065	23,017	2,869	0	-
1010000	ELEC PLANT IN SERV	3340000	ACCESSORY ELECTRIC EQUIPMENT	SG-P	56,699	781	15,243	4,246	7,811	25,447	3,172	0	-
1010000	ELEC PLANT IN SERV	3340000	ACCESSORY ELECTRIC EQUIPMENT	SG-U	14,656	202	3,940	1,098	2,019	6,578	820	0	-
1010000	ELEC PLANT IN SERV	3347000	ACCESSORY ELECT EQUIP - SUPV & ALARM	SG-P	1,623	22	436	122	224	728	91	0	-
1010000	ELEC PLANT IN SERV	3347000	ACCESSORY ELECT EQUIP - SUPV & ALARM	SG-U	64	1	17	5	9	29	4	0	-
1010000	ELEC PLANT IN SERV	3350000	MISC POWER PLANT EQUIP	SG-U	212	3	57	16	29	95	12	0	-
1010000	ELEC PLANT IN SERV	3351000	MISC POWER PLANT EQUIP - PRODUCTION	SG-P	2,471	34	664	185	340	1,109	138	0	-
1010000	ELEC PLANT IN SERV	3360000	"ROADS, RAILROADS & BRIDGES"	SG-P	21,323	294	5,733	1,597	2,938	9,570	1,193	0	-
1010000	ELEC PLANT IN SERV	3360000	"ROADS, RAILROADS & BRIDGES"	SG-U	4,287	59	1,152	321	591	1,924	240	0	-
1010000	ELEC PLANT IN SERV	3401000	LAND OWNED IN FEE	OR	75	-	75	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3401000	LAND OWNED IN FEE	SG	14,323	197	3,851	1,073	1,973	6,428	801	0	-
1010000	ELEC PLANT IN SERV	3402000	LAND RIGHTS	SG	5,758	79	1,548	431	793	2,584	322	0	-
1010000	ELEC PLANT IN SERV	3403000	WATER RIGHTS - OTHER PRODUCTION	SG	32,710	450	8,794	2,449	4,506	14,680	1,830	0	-
1010000	ELEC PLANT IN SERV	3410000	STRUCTURES & IMPROVEMENTS	OR	4	-	4	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3410000	STRUCTURES & IMPROVEMENTS	SG	276,144	3,802	74,239	20,678	38,042	123,934	15,448	0	-
1010000	ELEC PLANT IN SERV	3410000	STRUCTURES & IMPROVEMENTS	UT	69	-	-	-	-	69	-	-	-
1010000	ELEC PLANT IN SERV	3420000	"FUEL HOLDERS,PRODUCERS, ACCES"	SG	16,439	226	4,420	1,231	2,265	7,378	920	0	-
1010000	ELEC PLANT IN SERV	3430000	PRIME MOVERS	SG	4,027,556	55,454	1,082,774	301,593	554,843	1,807,580	225,312	0	-
1010000	ELEC PLANT IN SERV	3440000	GENERATORS	SG	594,086	8,180	159,715	44,486	81,842	266,628	33,235	0	-
1010000	ELEC PLANT IN SERV	3440000	GENERATORS	UT	285	-	-	-	-	285	-	-	-
1010000	ELEC PLANT IN SERV	3450000	ACCESSORY ELECTRIC EQUIPMENT	SG	462,407	6,367	124,314	34,626	63,702	207,530	25,868	0	-
1010000	ELEC PLANT IN SERV	3450000	ACCESSORY ELECTRIC EQUIPMENT	UT	81	-	-	-	-	81	-	-	-
1010000	ELEC PLANT IN SERV	3456000	Electric Equipment - Leasehold Improveme	OR	517	-	517	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3460000	MISCELLANEOUS PWR PLANT EQUIP	SG	24,841	342	6,678	1,860	3,422	11,149	1,390	0	-
1010000	ELEC PLANT IN SERV	3500000	LAND AND LAND RIGHTS	SG	841	12	226	63	116	377	47	0	-
1010000	ELEC PLANT IN SERV	3501000	LAND OWNED IN FEE	SG	63,412	873	17,048	4,748	8,736	28,459	3,547	0	-
1010000	ELEC PLANT IN SERV	3502000	LAND RIGHTS	SG	282,573	3,891	75,967	21,160	38,928	126,820	15,808	0	-
1010000	ELEC PLANT IN SERV	3520000	STRUCTURES & IMPROVEMENTS	SG	386,385	5,320	103,876	28,933	53,229	173,411	21,615	0	-
1010000	ELEC PLANT IN SERV	3530000	STATION EQUIPMENT	SG	2,519,851	34,695	677,441	188,692	347,139	1,130,917	140,967	0	-
1010000	ELEC PLANT IN SERV	3534000	STATION EQUIPMENT, STEP-UP TRANSFORMERS	SG	181,456	2,498	48,783	13,588	24,998	81,438	10,151	0	-
1010000	ELEC PLANT IN SERV	3537000	STATION EQUIPMENT-SUPERVISORY & ALARM	SG	26,109	359	7,019	1,955	3,597	11,718	1,461	0	-
1010000	ELEC PLANT IN SERV	3540000	TOWERS AND FIXTURES	SG	1,526,005	21,011	410,254	114,271	210,225	684,876	85,369	0	-
1010000	ELEC PLANT IN SERV	3550000	POLES AND FIXTURES	SG	1,278,839	17,608	343,805	95,762	176,175	573,947	71,541	0	-

PACIFICORP

Electric Plant in Service (Actuals)
Year End: 06/2023
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	3560000	OVERHEAD CONDUCTORS & DEVICES	SG	1,676,120	23,078	450,611	125,512	230,905	752,248	93,766	0	-
1010000	ELEC PLANT IN SERV	3570000	UNDERGROUND CONDUIT	SG	3,873	53	1,041	290	534	1,738	217	0	-
1010000	ELEC PLANT IN SERV	3580000	UNDERGROUND CONDUCTORS & DEVICES	SG	9,081	125	2,441	680	1,251	4,075	508	0	-
1010000	ELEC PLANT IN SERV	3590000	ROADS AND TRAILS	SG	12,141	167	3,264	909	1,673	5,449	679	0	-
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	1,606	1,606	-	-	-	-	-	-	-
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	28,101	-	-	-	-	28,101	-	-	-
1010000	ELEC PLANT IN SERV	3601000	LAND OWNED IN FEE	WA	2,095	-	-	2,095	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3601000	LAND OWNED IN FEE	WYP	847	-	-	-	847	-	-	-	-
1010000	ELEC PLANT IN SERV	3601000	LAND OWNED IN FEE	WYU	638	-	-	-	638	-	-	-	-
1010000	ELEC PLANT IN SERV	3602000	LAND RIGHTS	CA	1,204	1,204	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3602000	LAND RIGHTS	IDU	1,809	-	-	-	-	-	1,809	-	-
1010000	ELEC PLANT IN SERV	3602000	LAND RIGHTS	OR	6,442	-	6,442	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3602000	LAND RIGHTS	UT	12,514	-	-	-	-	12,514	-	-	-
1010000	ELEC PLANT IN SERV	3602000	LAND RIGHTS	WA	625	-	-	625	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3602000	LAND RIGHTS	WYP	4,807	-	-	-	4,807	-	-	-	-
1010000	ELEC PLANT IN SERV	3602000	LAND RIGHTS	WYU	6,999	-	-	-	6,999	-	-	-	-
1010000	ELEC PLANT IN SERV	3610000	STRUCTURES & IMPROVEMENTS	CA	8,656	8,656	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3610000	STRUCTURES & IMPROVEMENTS	IDU	4,316	-	-	-	-	-	4,316	-	-
1010000	ELEC PLANT IN SERV	3610000	STRUCTURES & IMPROVEMENTS	OR	35,034	-	35,034	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3610000	STRUCTURES & IMPROVEMENTS	UT	67,355	-	-	-	-	67,355	-	-	-
1010000	ELEC PLANT IN SERV	3610000	STRUCTURES & IMPROVEMENTS	WA	8,652	-	-	8,652	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3610000	STRUCTURES & IMPROVEMENTS	WYP	19,430	-	-	-	19,430	-	-	-	-
1010000	ELEC PLANT IN SERV	3610000	STRUCTURES & IMPROVEMENTS	WYU	5,027	-	-	-	5,027	-	-	-	-
1010000	ELEC PLANT IN SERV	3620000	STATION EQUIPMENT	CA	42,017	42,017	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3620000	STATION EQUIPMENT	IDU	49,251	-	-	-	-	-	49,251	-	-
1010000	ELEC PLANT IN SERV	3620000	STATION EQUIPMENT	OR	301,208	-	301,208	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3620000	STATION EQUIPMENT	UT	584,018	-	-	-	-	584,018	-	-	-
1010000	ELEC PLANT IN SERV	3620000	STATION EQUIPMENT	WA	87,466	-	-	87,466	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3620000	STATION EQUIPMENT	WYP	143,190	-	-	-	143,190	-	-	-	-
1010000	ELEC PLANT IN SERV	3620000	STATION EQUIPMENT	WYU	20,432	-	-	-	20,432	-	-	-	-
1010000	ELEC PLANT IN SERV	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	CA	893	893	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	IDU	602	-	-	-	-	-	602	-	-
1010000	ELEC PLANT IN SERV	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	OR	4,825	-	4,825	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	UT	7,742	-	-	-	-	7,742	-	-	-
1010000	ELEC PLANT IN SERV	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	WA	1,675	-	-	1,675	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	WYP	2,314	-	-	-	2,314	-	-	-	-
1010000	ELEC PLANT IN SERV	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	WYU	339	-	-	-	339	-	-	-	-
1010000	ELEC PLANT IN SERV	3640000	"POLES, TOWERS AND FIXTURES"	CA	107,509	107,509	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3640000	"POLES, TOWERS AND FIXTURES"	IDU	109,804	-	-	-	-	-	109,804	-	-
1010000	ELEC PLANT IN SERV	3640000	"POLES, TOWERS AND FIXTURES"	OR	516,891	-	516,891	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3640000	"POLES, TOWERS AND FIXTURES"	UT	479,764	-	-	-	-	479,764	-	-	-
1010000	ELEC PLANT IN SERV	3640000	"POLES, TOWERS AND FIXTURES"	WA	128,569	-	-	128,569	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3640000	"POLES, TOWERS AND FIXTURES"	WYP	159,783	-	-	-	159,783	-	-	-	-
1010000	ELEC PLANT IN SERV	3640000	"POLES, TOWERS AND FIXTURES"	WYU	31,556	-	-	-	31,556	-	-	-	-
1010000	ELEC PLANT IN SERV	3650000	OVERHEAD CONDUCTORS & DEVICES	CA	63,611	63,611	-	-	-	-	-	-	-

PACIFICORP

Electric Plant in Service (Actuals)
Year End: 06/2023
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	IDU	48,216	-	-	-	-	-	48,216	-	-
1010000	ELEC PLANT IN SERV	3650000	OVERHEAD CONDUCTORS & DEVICES	OR	325,013	-	325,013	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3650000	OVERHEAD CONDUCTORS & DEVICES	UT	297,195	-	-	-	-	297,195	-	-	-
1010000	ELEC PLANT IN SERV	3650000	OVERHEAD CONDUCTORS & DEVICES	WA	91,846	-	-	91,846	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3650000	OVERHEAD CONDUCTORS & DEVICES	WYP	119,335	-	-	-	119,335	-	-	-	-
1010000	ELEC PLANT IN SERV	3650000	OVERHEAD CONDUCTORS & DEVICES	WYU	15,604	-	-	-	15,604	-	-	-	-
1010000	ELEC PLANT IN SERV	3660000	UNDERGROUND CONDUIT	CA	19,772	19,772	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3660000	UNDERGROUND CONDUIT	IDU	14,009	-	-	-	-	-	14,009	-	-
1010000	ELEC PLANT IN SERV	3660000	UNDERGROUND CONDUIT	OR	120,811	-	120,811	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3660000	UNDERGROUND CONDUIT	UT	271,849	-	-	-	-	271,849	-	-	-
1010000	ELEC PLANT IN SERV	3660000	UNDERGROUND CONDUIT	WA	24,648	-	-	24,648	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3660000	UNDERGROUND CONDUIT	WYP	31,160	-	-	-	31,160	-	-	-	-
1010000	ELEC PLANT IN SERV	3660000	UNDERGROUND CONDUIT	WYU	5,555	-	-	-	5,555	-	-	-	-
1010000	ELEC PLANT IN SERV	3670000	UNDERGROUND CONDUCTORS & DEVICES	CA	22,172	22,172	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3670000	UNDERGROUND CONDUCTORS & DEVICES	IDU	36,231	-	-	-	-	-	36,231	-	-
1010000	ELEC PLANT IN SERV	3670000	UNDERGROUND CONDUCTORS & DEVICES	OR	235,066	-	235,066	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3670000	UNDERGROUND CONDUCTORS & DEVICES	UT	707,058	-	-	-	-	707,058	-	-	-
1010000	ELEC PLANT IN SERV	3670000	UNDERGROUND CONDUCTORS & DEVICES	WA	37,282	-	-	37,282	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3670000	UNDERGROUND CONDUCTORS & DEVICES	WYP	53,486	-	-	-	53,486	-	-	-	-
1010000	ELEC PLANT IN SERV	3670000	UNDERGROUND CONDUCTORS & DEVICES	WYU	19,778	-	-	-	19,778	-	-	-	-
1010000	ELEC PLANT IN SERV	3680000	LINE TRANSFORMERS	CA	60,543	60,543	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3680000	LINE TRANSFORMERS	IDU	94,650	-	-	-	-	-	94,650	-	-
1010000	ELEC PLANT IN SERV	3680000	LINE TRANSFORMERS	OR	532,451	-	532,451	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3680000	LINE TRANSFORMERS	UT	666,145	-	-	-	-	666,145	-	-	-
1010000	ELEC PLANT IN SERV	3680000	LINE TRANSFORMERS	WA	130,727	-	-	130,727	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3680000	LINE TRANSFORMERS	WYP	120,645	-	-	-	120,645	-	-	-	-
1010000	ELEC PLANT IN SERV	3680000	LINE TRANSFORMERS	WYU	16,871	-	-	-	16,871	-	-	-	-
1010000	ELEC PLANT IN SERV	3691000	SERVICES - OVERHEAD	CA	12,029	12,029	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3691000	SERVICES - OVERHEAD	IDU	10,420	-	-	-	-	-	10,420	-	-
1010000	ELEC PLANT IN SERV	3691000	SERVICES - OVERHEAD	OR	117,296	-	117,296	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3691000	SERVICES - OVERHEAD	UT	109,185	-	-	-	-	109,185	-	-	-
1010000	ELEC PLANT IN SERV	3691000	SERVICES - OVERHEAD	WA	28,354	-	-	28,354	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3691000	SERVICES - OVERHEAD	WYP	20,892	-	-	-	20,892	-	-	-	-
1010000	ELEC PLANT IN SERV	3691000	SERVICES - OVERHEAD	WYU	4,745	-	-	-	4,745	-	-	-	-
1010000	ELEC PLANT IN SERV	3692000	SERVICES - UNDERGROUND	CA	18,250	18,250	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3692000	SERVICES - UNDERGROUND	IDU	43,719	-	-	-	-	-	43,719	-	-
1010000	ELEC PLANT IN SERV	3692000	SERVICES - UNDERGROUND	OR	242,221	-	242,221	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3692000	SERVICES - UNDERGROUND	UT	321,089	-	-	-	-	321,089	-	-	-
1010000	ELEC PLANT IN SERV	3692000	SERVICES - UNDERGROUND	WA	51,712	-	-	51,712	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3692000	SERVICES - UNDERGROUND	WYP	40,854	-	-	-	40,854	-	-	-	-
1010000	ELEC PLANT IN SERV	3692000	SERVICES - UNDERGROUND	WYU	13,980	-	-	-	13,980	-	-	-	-
1010000	ELEC PLANT IN SERV	3700000	METERS	CA	9,216	9,216	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3700000	METERS	IDU	17,804	-	-	-	-	-	17,804	-	-
1010000	ELEC PLANT IN SERV	3700000	METERS	OR	105,898	-	105,898	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3700000	METERS	UT	126,671	-	-	-	-	126,671	-	-	-
1010000	ELEC PLANT IN SERV	3700000	METERS	WA	15,817	-	-	15,817	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3700000	METERS	WYP	15,109	-	-	-	15,109	-	-	-	-
1010000	ELEC PLANT IN SERV	3700000	METERS	WYU	2,998	-	-	-	2,998	-	-	-	-
1010000	ELEC PLANT IN SERV	3710000	INSTALL ON CUSTOMERS PREMISES	CA	288	288	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3710000	INSTALL ON CUSTOMERS PREMISES	IDU	171	-	-	-	-	-	171	-	-
1010000	ELEC PLANT IN SERV	3710000	INSTALL ON CUSTOMERS PREMISES	OR	2,686	-	2,686	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3710000	INSTALL ON CUSTOMERS PREMISES	UT	4,184	-	-	-	-	4,184	-	-	-

Electric Plant in Service (Actuals)
Year End: 06/2023
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	3710000	INSTALL ON CUSTOMERS PREMISES	WA	530	-	-	530	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3710000	INSTALL ON CUSTOMERS PREMISES	WYP	863	-	-	-	863	-	-	-	-
1010000	ELEC PLANT IN SERV	3710000	INSTALL ON CUSTOMERS PREMISES	WYU	150	-	-	-	150	-	-	-	-
1010000	ELEC PLANT IN SERV	3730000	STREET LIGHTING & SIGNAL SYSTEMS	CA	790	790	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3730000	STREET LIGHTING & SIGNAL SYSTEMS	IDU	849	-	-	-	-	-	849	-	-
1010000	ELEC PLANT IN SERV	3730000	STREET LIGHTING & SIGNAL SYSTEMS	OR	25,130	-	25,130	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3730000	STREET LIGHTING & SIGNAL SYSTEMS	UT	21,612	-	-	-	-	21,612	-	-	-
1010000	ELEC PLANT IN SERV	3730000	STREET LIGHTING & SIGNAL SYSTEMS	WA	3,750	-	-	3,750	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3730000	STREET LIGHTING & SIGNAL SYSTEMS	WYP	8,802	-	-	-	8,802	-	-	-	-
1010000	ELEC PLANT IN SERV	3730000	STREET LIGHTING & SIGNAL SYSTEMS	WYU	2,255	-	-	-	2,255	-	-	-	-
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	-	-	-
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	347	76	80	553	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	197	2,061	550	956	3,342	410	0	-
1010000	ELEC PLANT IN SERV	3891000	LAND OWNED IN FEE	UT	2,677	-	-	-	-	2,677	-	-	-
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	3,095	-	-	-	3,095	-	-	-	-
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	3	26	7	12	42	5	0	-
1010000	ELEC PLANT IN SERV	3892000	LAND RIGHTS	UT	96	-	-	-	-	96	-	-	-
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	3,893	3,893	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3900000	STRUCTURES AND IMPROVEMENTS	CN	8,219	186	2,524	550	583	4,027	349	-	-
1010000	ELEC PLANT IN SERV	3900000	STRUCTURES AND IMPROVEMENTS	IDU	13,427	-	-	-	-	-	13,427	-	-
1010000	ELEC PLANT IN SERV	3900000	STRUCTURES AND IMPROVEMENTS	OR	38,666	-	38,666	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3900000	STRUCTURES AND IMPROVEMENTS	SE	941	12	248	64	140	421	57	0	-
1010000	ELEC PLANT IN SERV	3900000	STRUCTURES AND IMPROVEMENTS	SG	12,024	166	3,232	900	1,656	5,396	673	0	-
1010000	ELEC PLANT IN SERV	3900000	STRUCTURES AND IMPROVEMENTS	SO	110,799	2,907	30,387	8,106	14,091	49,267	6,041	0	-
1010000	ELEC PLANT IN SERV	3900000	STRUCTURES AND IMPROVEMENTS	UT	48,410	-	-	-	-	48,410	-	-	-
1010000	ELEC PLANT IN SERV	3900000	STRUCTURES AND IMPROVEMENTS	WA	11,906	-	-	11,906	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3900000	STRUCTURES AND IMPROVEMENTS	WYP	16,273	-	-	-	16,273	-	-	-	-
1010000	ELEC PLANT IN SERV	3900000	STRUCTURES AND IMPROVEMENTS	WYU	4,435	-	-	-	4,435	-	-	-	-
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	5,684	-	5,684	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	SO	2,197	58	603	161	279	977	120	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	2,574	-	-	2,574	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	WYP	4,752	-	-	-	4,752	-	-	-	-
1010000	ELEC PLANT IN SERV	3910000	OFFICE FURNITURE	CA	110	110	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3910000	OFFICE FURNITURE	CN	847	19	260	57	60	415	36	-	-
1010000	ELEC PLANT IN SERV	3910000	OFFICE FURNITURE	IDU	80	-	-	-	-	-	80	-	-

PACIFICORP

Electric Plant in Service (Actuals)
Year End: 06/2023
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	3910000	OFFICE FURNITURE	OR	1,362	-	1,362	-	-	-	-	-	-
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	2,026	28	545	152	279	909	113	0	-
1010000	ELEC PLANT IN SERV	3910000	OFFICE FURNITURE	SO	15,994	420	4,387	1,170	2,034	7,112	872	0	-
1010000	ELEC PLANT IN SERV	3910000	OFFICE FURNITURE	UT	1,082	-	-	-	-	1,082	-	-	-
1010000	ELEC PLANT IN SERV	3910000	OFFICE FURNITURE	WA	58	-	-	58	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3910000	OFFICE FURNITURE	WYP	552	-	-	-	552	-	-	-	-
1010000	ELEC PLANT IN SERV	3910000	OFFICE FURNITURE	WYU	46	-	-	-	46	-	-	-	-
1010000	ELEC PLANT IN SERV	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	CA	49	49	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	CN	2,022	46	621	135	144	991	86	-	-
1010000	ELEC PLANT IN SERV	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	IDU	408	-	-	-	-	-	408	-	-
1010000	ELEC PLANT IN SERV	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	OR	987	-	987	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	SE	23	0	6	2	3	10	1	0	-
1010000	ELEC PLANT IN SERV	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	SG	2,520	35	677	189	347	1,131	141	0	-
1010000	ELEC PLANT IN SERV	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	SO	63,477	1,665	17,409	4,644	8,073	28,225	3,461	0	-
1010000	ELEC PLANT IN SERV	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	UT	808	-	-	-	-	808	-	-	-
1010000	ELEC PLANT IN SERV	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	WA	318	-	-	318	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	WYP	1,274	-	-	-	1,274	-	-	-	-
1010000	ELEC PLANT IN SERV	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	WYU	72	-	-	-	72	-	-	-	-
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	2	-	2	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3913000	OFFICE EQUIPMENT	SG	30	0	8	2	4	14	2	0	-
1010000	ELEC PLANT IN SERV	3913000	OFFICE EQUIPMENT	SO	739	19	203	54	94	329	40	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	327	-	-	-	-	-	327	-	-
1010000	ELEC PLANT IN SERV	3920100	1/4 TON MINI-PICKUPS AND VANS	OR	1,859	-	1,859	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3920100	1/4 TON MINI-PICKUPS AND VANS	SE	25	0	7	2	4	11	2	0	-
1010000	ELEC PLANT IN SERV	3920100	1/4 TON MINI-PICKUPS AND VANS	SG	545	8	147	41	75	245	30	0	-
1010000	ELEC PLANT IN SERV	3920100	1/4 TON MINI-PICKUPS AND VANS	SO	705	18	193	52	90	313	38	0	-
1010000	ELEC PLANT IN SERV	3920100	1/4 TON MINI-PICKUPS AND VANS	UT	3,457	-	-	-	-	3,457	-	-	-
1010000	ELEC PLANT IN SERV	3920100	1/4 TON MINI-PICKUPS AND VANS	WA	239	-	-	239	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3920100	1/4 TON MINI-PICKUPS AND VANS	WYP	731	-	-	-	731	-	-	-	-
1010000	ELEC PLANT IN SERV	3920200	MID AND FULL SIZE AUTOMOBILES	OR	282	-	282	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3920200	MID AND FULL SIZE AUTOMOBILES	SO	239	6	66	17	30	106	13	0	-
1010000	ELEC PLANT IN SERV	3920200	MID AND FULL SIZE AUTOMOBILES	UT	693	-	-	-	-	693	-	-	-
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	467	467	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	IDU	1,849	-	-	-	-	-	1,849	-	-
1010000	ELEC PLANT IN SERV	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	OR	6,101	-	6,101	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	SE	71	1	19	5	10	32	4	0	-
1010000	ELEC PLANT IN SERV	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	SG	8,792	121	2,364	658	1,211	3,946	492	0	-
1010000	ELEC PLANT IN SERV	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	SO	1,154	30	316	84	147	513	63	0	-
1010000	ELEC PLANT IN SERV	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	UT	9,396	-	-	-	-	9,396	-	-	-
1010000	ELEC PLANT IN SERV	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	WA	1,395	-	-	1,395	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	WYP	2,532	-	-	-	2,532	-	-	-	-
1010000	ELEC PLANT IN SERV	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	WYU	364	-	-	-	364	-	-	-	-
1010000	ELEC PLANT IN SERV	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	CA	1,367	1,367	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	IDU	4,558	-	-	-	-	-	4,558	-	-
1010000	ELEC PLANT IN SERV	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	OR	14,770	-	14,770	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	SE	181	2	48	12	27	81	11	0	-

PACIFICORP

Electric Plant in Service (Actuals)
Year End: 06/2023
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	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	SG	7,534	104	2,026	564	1,038	3,381	421	0	-
1010000	ELEC PLANT IN SERV	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	SO	364	10	100	27	46	162	20	0	-
1010000	ELEC PLANT IN SERV	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	UT	24,730	-	-	-	-	24,730	-	-	-
1010000	ELEC PLANT IN SERV	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	WA	3,428	-	-	3,428	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	WYP	6,311	-	-	-	6,311	-	-	-	-
1010000	ELEC PLANT IN SERV	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	WYU	1,303	-	-	-	1,303	-	-	-	-
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	4,155	57	1,117	311	572	1,865	232	0	-
1010000	ELEC PLANT IN SERV	3920600	DUMP TRUCKS	UT	149	-	-	-	-	149	-	-	-
1010000	ELEC PLANT IN SERV	3920600	DUMP TRUCKS	WA	86	-	-	86	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3920900	TRAILERS	CA	642	642	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3920900	TRAILERS	IDU	2,486	-	-	-	-	-	2,486	-	-
1010000	ELEC PLANT IN SERV	3920900	TRAILERS	OR	5,950	-	5,950	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3920900	TRAILERS	SE	41	1	11	3	6	18	2	0	-
1010000	ELEC PLANT IN SERV	3920900	TRAILERS	SG	2,042	28	549	153	281	916	114	0	-
1010000	ELEC PLANT IN SERV	3920900	TRAILERS	SO	1,180	31	324	86	150	525	64	0	-
1010000	ELEC PLANT IN SERV	3920900	TRAILERS	UT	13,145	-	-	-	-	13,145	-	-	-
1010000	ELEC PLANT IN SERV	3920900	TRAILERS	WA	1,026	-	-	1,026	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3920900	TRAILERS	WYP	4,469	-	-	-	4,469	-	-	-	-
1010000	ELEC PLANT IN SERV	3920900	TRAILERS	WYU	1,252	-	-	-	1,252	-	-	-	-
1010000	ELEC PLANT IN SERV	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	CA	304	304	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	IDU	252	-	-	-	-	-	252	-	-
1010000	ELEC PLANT IN SERV	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	OR	828	-	828	-	-	-	-	-	-
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	1,664	23	447	125	229	747	93	0	-
1010000	ELEC PLANT IN SERV	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	SO	93	2	26	7	12	41	5	0	-
1010000	ELEC PLANT IN SERV	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	UT	523	-	-	-	-	523	-	-	-
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	469	-	-	-	469	-	-	-	-
1010000	ELEC PLANT IN SERV	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	WYU	121	-	-	-	121	-	-	-	-
1010000	ELEC PLANT IN SERV	3921900	OVER-THE-ROAD SEMI-TRACTORS	OR	497	-	497	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3921900	OVER-THE-ROAD SEMI-TRACTORS	SG	757	10	203	57	104	340	42	0	-
1010000	ELEC PLANT IN SERV	3921900	OVER-THE-ROAD SEMI-TRACTORS	SO	215	6	59	16	27	95	12	0	-
1010000	ELEC PLANT IN SERV	3921900	OVER-THE-ROAD SEMI-TRACTORS	UT	2,049	-	-	-	-	2,049	-	-	-
1010000	ELEC PLANT IN SERV	3921900	OVER-THE-ROAD SEMI-TRACTORS	WA	456	-	-	456	-	-	-	-	-
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	79	821	219	381	1,331	163	0	-
1010000	ELEC PLANT IN SERV	3930000	STORES EQUIPMENT	CA	108	108	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3930000	STORES EQUIPMENT	IDU	891	-	-	-	-	-	891	-	-
1010000	ELEC PLANT IN SERV	3930000	STORES EQUIPMENT	OR	3,157	-	3,157	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3930000	STORES EQUIPMENT	SG	6,965	96	1,873	522	960	3,126	390	0	-
1010000	ELEC PLANT IN SERV	3930000	STORES EQUIPMENT	SO	243	6	67	18	31	108	13	0	-
1010000	ELEC PLANT IN SERV	3930000	STORES EQUIPMENT	UT	4,245	-	-	-	-	4,245	-	-	-
1010000	ELEC PLANT IN SERV	3930000	STORES EQUIPMENT	WA	742	-	-	742	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3930000	STORES EQUIPMENT	WYP	1,562	-	-	-	1,562	-	-	-	-
1010000	ELEC PLANT IN SERV	3930000	STORES EQUIPMENT	WYU	1	-	-	-	1	-	-	-	-
1010000	ELEC PLANT IN SERV	3940000	"TLS, SHOP, GAR EQUIPMENT"	CA	1,128	1,128	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3940000	"TLS, SHOP, GAR EQUIPMENT"	IDU	2,364	-	-	-	-	-	2,364	-	-
1010000	ELEC PLANT IN SERV	3940000	"TLS, SHOP, GAR EQUIPMENT"	OR	10,912	-	10,912	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3940000	"TLS, SHOP, GAR EQUIPMENT"	SE	126	2	33	9	19	56	8	0	-
1010000	ELEC PLANT IN SERV	3940000	"TLS, SHOP, GAR EQUIPMENT"	SG	23,058	317	6,199	1,727	3,177	10,349	1,290	0	-

PACIFICORP

Electric Plant in Service (Actuals)
Year End: 06/2023
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	3940000	"TLS, SHOP, GAR EQUIPMENT"	SO	1,802	47	494	132	229	801	98	0	-
1010000	ELEC PLANT IN SERV	3940000	"TLS, SHOP, GAR EQUIPMENT"	UT	16,888	-	-	-	-	16,888	-	-	-
1010000	ELEC PLANT IN SERV	3940000	"TLS, SHOP, GAR EQUIPMENT"	WA	2,992	-	-	2,992	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3940000	"TLS, SHOP, GAR EQUIPMENT"	WYP	4,202	-	-	-	4,202	-	-	-	-
1010000	ELEC PLANT IN SERV	3940000	"TLS, SHOP, GAR EQUIPMENT"	WYU	297	-	-	-	297	-	-	-	-
1010000	ELEC PLANT IN SERV	3950000	LABORATORY EQUIPMENT	CA	798	798	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3950000	LABORATORY EQUIPMENT	IDU	1,484	-	-	-	-	-	1,484	-	-
1010000	ELEC PLANT IN SERV	3950000	LABORATORY EQUIPMENT	OR	10,594	-	10,594	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3950000	LABORATORY EQUIPMENT	SE	1,327	17	349	90	197	593	80	0	-
1010000	ELEC PLANT IN SERV	3950000	LABORATORY EQUIPMENT	SG	7,525	104	2,023	564	1,037	3,377	421	0	-
1010000	ELEC PLANT IN SERV	3950000	LABORATORY EQUIPMENT	SO	5,071	133	1,391	371	645	2,255	276	0	-
1010000	ELEC PLANT IN SERV	3950000	LABORATORY EQUIPMENT	UT	10,207	-	-	-	-	10,207	-	-	-
1010000	ELEC PLANT IN SERV	3950000	LABORATORY EQUIPMENT	WA	1,463	-	-	1,463	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3950000	LABORATORY EQUIPMENT	WYP	3,475	-	-	-	3,475	-	-	-	-
1010000	ELEC PLANT IN SERV	3950000	LABORATORY EQUIPMENT	WYU	134	-	-	-	134	-	-	-	-
1010000	ELEC PLANT IN SERV	3960300	"AERIAL LIFT PB TRUCKS, 10000#-16000# GV	CA	2,235	2,235	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3960300	"AERIAL LIFT PB TRUCKS, 10000#-16000# GV	IDU	3,691	-	-	-	-	-	3,691	-	-
1010000	ELEC PLANT IN SERV	3960300	"AERIAL LIFT PB TRUCKS, 10000#-16000# GV	OR	15,386	-	15,386	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3960300	"AERIAL LIFT PB TRUCKS, 10000#-16000# GV	SG	254	3	68	19	35	114	14	0	-
1010000	ELEC PLANT IN SERV	3960300	"AERIAL LIFT PB TRUCKS, 10000#-16000# GV	SO	940	25	258	69	120	418	51	0	-
1010000	ELEC PLANT IN SERV	3960300	"AERIAL LIFT PB TRUCKS, 10000#-16000# GV	UT	16,298	-	-	-	-	16,298	-	-	-
1010000	ELEC PLANT IN SERV	3960300	"AERIAL LIFT PB TRUCKS, 10000#-16000# GV	WA	3,389	-	-	3,389	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3960300	"AERIAL LIFT PB TRUCKS, 10000#-16000# GV	WYP	6,540	-	-	-	6,540	-	-	-	-
1010000	ELEC PLANT IN SERV	3960300	"AERIAL LIFT PB TRUCKS, 10000#-16000# GV	WYU	1,408	-	-	-	1,408	-	-	-	-
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	1,066	-	1,066	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	SG	124	2	33	9	17	56	7	0	-
1010000	ELEC PLANT IN SERV	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	UT	1,268	-	-	-	-	1,268	-	-	-
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	1,665	1,665	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	IDU	4,548	-	-	-	-	-	4,548	-	-
1010000	ELEC PLANT IN SERV	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	OR	16,562	-	16,562	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	SG	1,231	17	331	92	170	553	69	0	-
1010000	ELEC PLANT IN SERV	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	SO	1,470	39	403	108	187	654	80	0	-
1010000	ELEC PLANT IN SERV	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	UT	18,180	-	-	-	-	18,180	-	-	-
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	8,397	-	-	-	8,397	-	-	-	-
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	1,542	-	1,542	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3961000	CRANES	SG	3,010	41	809	225	415	1,351	168	0	-
1010000	ELEC PLANT IN SERV	3961000	CRANES	UT	1,083	-	-	-	-	1,083	-	-	-
1010000	ELEC PLANT IN SERV	3961000	CRANES	WYP	608	-	-	-	608	-	-	-	-
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	36,312	500	9,762	2,719	5,002	16,297	2,031	0	-
1010000	ELEC PLANT IN SERV	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	SO	710	19	195	52	90	316	39	0	-
1010000	ELEC PLANT IN SERV	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	UT	2,940	-	-	-	-	2,940	-	-	-
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	1,676	1,676	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	IDU	3,884	-	-	-	-	-	3,884	-	-
1010000	ELEC PLANT IN SERV	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	OR	11,894	-	11,894	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	SG	325	4	87	24	45	146	18	0	-
1010000	ELEC PLANT IN SERV	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	SO	983	26	270	72	125	437	54	0	-

PACIFICORP

Electric Plant in Service (Actuals)
Year End: 06/2023
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	UT	18,508	-	-	-	-	18,508	-	-	-
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	5,188	-	-	-	5,188	-	-	-	-
1010000	ELEC PLANT IN SERV	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	WYU	1,661	-	-	-	1,661	-	-	-	-
1010000	ELEC PLANT IN SERV	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	CA	970	970	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	IDU	2,323	-	-	-	-	-	2,323	-	-
1010000	ELEC PLANT IN SERV	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	OR	5,063	-	5,063	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	SE	237	3	62	16	35	106	14	0	-
1010000	ELEC PLANT IN SERV	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	SG	6,995	96	1,881	524	964	3,140	391	0	-
1010000	ELEC PLANT IN SERV	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	SO	561	15	154	41	71	249	31	0	-
1010000	ELEC PLANT IN SERV	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	UT	10,672	-	-	-	-	10,672	-	-	-
1010000	ELEC PLANT IN SERV	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	WA	1,541	-	-	1,541	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	WYP	3,262	-	-	-	3,262	-	-	-	-
1010000	ELEC PLANT IN SERV	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	WYU	955	-	-	-	955	-	-	-	-
1010000	ELEC PLANT IN SERV	3970000	COMMUNICATION EQUIPMENT	CA	6,057	6,057	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3970000	COMMUNICATION EQUIPMENT	CN	3,459	78	1,062	231	246	1,695	147	-	-
1010000	ELEC PLANT IN SERV	3970000	COMMUNICATION EQUIPMENT	IDU	14,405	-	-	-	-	-	14,405	-	-
1010000	ELEC PLANT IN SERV	3970000	COMMUNICATION EQUIPMENT	OR	63,307	-	63,307	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3970000	COMMUNICATION EQUIPMENT	SE	280	4	74	19	42	125	17	0	-
1010000	ELEC PLANT IN SERV	3970000	COMMUNICATION EQUIPMENT	SG	203,467	2,801	54,700	15,236	28,030	91,317	11,382	0	-
1010000	ELEC PLANT IN SERV	3970000	COMMUNICATION EQUIPMENT	SO	95,729	2,511	26,254	7,004	12,174	42,566	5,220	0	-
1010000	ELEC PLANT IN SERV	3970000	COMMUNICATION EQUIPMENT	UT	73,133	-	-	-	-	73,133	-	-	-
1010000	ELEC PLANT IN SERV	3970000	COMMUNICATION EQUIPMENT	WA	13,195	-	-	13,195	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3970000	COMMUNICATION EQUIPMENT	WYP	26,489	-	-	-	26,489	-	-	-	-
1010000	ELEC PLANT IN SERV	3970000	COMMUNICATION EQUIPMENT	WYU	6,782	-	-	-	6,782	-	-	-	-
1010000	ELEC PLANT IN SERV	3972000	MOBILE RADIO EQUIPMENT	CA	335	335	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3972000	MOBILE RADIO EQUIPMENT	IDU	114	-	-	-	-	-	114	-	-
1010000	ELEC PLANT IN SERV	3972000	MOBILE RADIO EQUIPMENT	OR	976	-	976	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3972000	MOBILE RADIO EQUIPMENT	SE	82	1	22	6	12	37	5	0	-
1010000	ELEC PLANT IN SERV	3972000	MOBILE RADIO EQUIPMENT	SG	3,385	47	910	253	466	1,519	189	0	-
1010000	ELEC PLANT IN SERV	3972000	MOBILE RADIO EQUIPMENT	SO	107	3	29	8	14	48	6	0	-
1010000	ELEC PLANT IN SERV	3972000	MOBILE RADIO EQUIPMENT	UT	600	-	-	-	-	600	-	-	-
1010000	ELEC PLANT IN SERV	3972000	MOBILE RADIO EQUIPMENT	WA	61	-	-	61	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3972000	MOBILE RADIO EQUIPMENT	WYP	182	-	-	-	182	-	-	-	-
1010000	ELEC PLANT IN SERV	3972000	MOBILE RADIO EQUIPMENT	WYU	41	-	-	-	41	-	-	-	-
1010000	ELEC PLANT IN SERV	3980000	MISCELLANEOUS EQUIPMENT	CA	58	58	-	-	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3980000	MISCELLANEOUS EQUIPMENT	CN	71	2	22	5	5	35	3	-	-
1010000	ELEC PLANT IN SERV	3980000	MISCELLANEOUS EQUIPMENT	IDU	84	-	-	-	-	-	84	-	-
1010000	ELEC PLANT IN SERV	3980000	MISCELLANEOUS EQUIPMENT	OR	1,374	-	1,374	-	-	-	-	-	-
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	3,114	43	837	233	429	1,397	174	0	-
1010000	ELEC PLANT IN SERV	3980000	MISCELLANEOUS EQUIPMENT	SO	1,575	41	432	115	200	700	86	0	-
1010000	ELEC PLANT IN SERV	3980000	MISCELLANEOUS EQUIPMENT	UT	1,741	-	-	-	-	1,741	-	-	-
1010000	ELEC PLANT IN SERV	3980000	MISCELLANEOUS EQUIPMENT	WA	191	-	-	191	-	-	-	-	-
1010000	ELEC PLANT IN SERV	3980000	MISCELLANEOUS EQUIPMENT	WYP	276	-	-	-	276	-	-	-	-
1010000	ELEC PLANT IN SERV	3980000	MISCELLANEOUS EQUIPMENT	WYU	17	-	-	-	17	-	-	-	-
1010000	ELEC PLANT IN SERV	3992100	LAND OWNED IN FEE	SE	1,823	23	480	124	271	815	110	0	-
1010000 Total					**32,587,639**	**724,222**	**9,064,731**	**2,401,722**	**4,188,491**	**14,419,644**	**1,788,829**	**0**	**-**
1019000	ELEC PLT IN SERV-OTH	140109	Land-Non-Rec	SG	(11)	(0)	(3)	(1)	(1)	(5)	(1)	(0)	-
1019000	ELEC PLT IN SERV-OTH	140129	ELECTRIC PLANT IN SERVICE - OTHER	SO	(802)	(21)	(220)	(59)	(102)	(356)	(44)	(0)	-
1019000	ELEC PLT IN SERV-OTH	140139	PRODUCTION PLANT-NON-RECONCILED	SG	(18,735)	(258)	(5,037)	(1,403)	(2,581)	(8,408)	(1,048)	(0)	-
1019000	ELEC PLT IN SERV-OTH	140149	TRANS PLANT NON-RECONCILED	SG	(2,897)	(40)	(779)	(217)	(399)	(1,300)	(162)	(0)	-

PACIFICORP

Electric Plant in Service (Actuals)
Year End: 06/2023
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1019000	ELEC PLT IN SERV-OTH	140169	DISTRIBN- NON-RECONCILED	CA	(32)	(32)	-	-	-	-	-	-	-
1019000	ELEC PLT IN SERV-OTH	140169	DISTRIBN- NON-RECONCILED	IDU	(46)	-	-	-	-	-	(46)	-	-
1019000	ELEC PLT IN SERV-OTH	140169	DISTRIBN- NON-RECONCILED	OR	(686)	-	(686)	-	-	-	-	-	-
1019000	ELEC PLT IN SERV-OTH	140169	DISTRIBN- NON-RECONCILED	UT	(862)	-	-	-	-	(862)	-	-	-
1019000	ELEC PLT IN SERV-OTH	140169	DISTRIBN- NON-RECONCILED	WA	(303)	-	-	(303)	-	-	-	-	-
1019000	ELEC PLT IN SERV-OTH	140169	DISTRIBN- NON-RECONCILED	WYU	(212)	-	-	-	(212)	-	-	-	-
1019000 Total					**(24,584)**	**(351)**	**(6,724)**	**(1,982)**	**(3,295)**	**(10,931)**	**(1,300)**	**(0)**	**-**
1020000	ELEC PL PUR OR SLD	0	ELECTRIC PLANT PURCHASED OR SOLD	SG	(553)	(8)	(149)	(41)	(76)	(248)	(31)	(0)	-
1020000	ELEC PL PUR OR SLD	140708	CONTRA ELEC PLANT PURCH OR SOLD - LOSS	SG	553	8	149	41	76	248	31	0	-
1020000 Total					**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
1061000	DIST COMP CONST NOT	0	DISTRIB COMPLETED CONSTRUCTN NOT CLASSIF	CA	18,529	18,529	-	-	-	-	-	-	-
1061000	DIST COMP CONST NOT	0	DISTRIB COMPLETED CONSTRUCTN NOT CLASSIF	IDU	2,259	-	-	-	-	-	2,259	-	-
1061000	DIST COMP CONST NOT	0	DISTRIB COMPLETED CONSTRUCTN NOT CLASSIF	OR	25,225	-	25,225	-	-	-	-	-	-
1061000	DIST COMP CONST NOT	0	DISTRIB COMPLETED CONSTRUCTN NOT CLASSIF	UT	27,824	-	-	-	-	27,824	-	-	-
1061000	DIST COMP CONST NOT	0	DISTRIB COMPLETED CONSTRUCTN NOT CLASSIF	WA	12,947	-	-	12,947	-	-	-	-	-
1061000	DIST COMP CONST NOT	0	DISTRIB COMPLETED CONSTRUCTN NOT CLASSIF	WYU	6,363	-	-	-	6,363	-	-	-	-
1061000 Total					**93,147**	**18,529**	**25,225**	**12,947**	**6,363**	**27,824**	**2,259**	**-**	**-**
1062000	TRAN COMP CONST NOT	0	TRANSM COMPLETED CONSTRUCTN NOT CLASSIFI	SG	127,341	1,753	34,234	9,536	17,543	57,151	7,124	0	-
1062000 Total					**127,341**	**1,753**	**34,234**	**9,536**	**17,543**	**57,151**	**7,124**	**0**	**-**
1063000	PROD COMP CONST NOT	0	PROD COMPLETED CONSTRUCTN NOT CLASSIFIED	SG	36,524	503	9,819	2,735	5,032	16,392	2,043	0	-
1063000 Total					**36,524**	**503**	**9,819**	**2,735**	**5,032**	**16,392**	**2,043**	**0**	**-**
1064000	GEN COMP CONST NOT	0	GENERAL COMPLETED CONSTRUCTN NOT CLASSIF	SO	66,213	1,737	18,159	4,844	8,421	29,442	3,610	0	-
1064000 Total					**66,213**	**1,737**	**18,159**	**4,844**	**8,421**	**29,442**	**3,610**	**0**	**-**
Grand Total					**32,886,279**	**746,393**	**9,145,444**	**2,429,801**	**4,222,554**	**14,539,521**	**1,802,566**	**0**	**-**

B9. CAPITAL LEASE PLANT

Capital Lease (Actuals)
Year End: 06/2023
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	3908230	(FINANCE LEASES-GAS)	SG	12,159	167	3,269	911	1,675	5,457	680	0	-
1011000 Total					**14,874**	**167**	**5,983**	**911**	**1,675**	**5,457**	**680**	**0**	**-**
1011500	CAP LEASES–ACCM AMRT	3908220	(FINANCE LEASES-BLDGS)	OR	(2,023)	-	(2,023)	-	-	-	-	-	-
1011500	CAP LEASES–ACCM AMRT	3908230	(FINANCE LEASES-GAS)	SG	(4,101)	(56)	(1,103)	(307)	(565)	(1,841)	(229)	(0)	-
1011500 Total					**(6,124)**	**(56)**	**(3,126)**	**(307)**	**(565)**	**(1,841)**	**(229)**	**(0)**	**-**
1011900	PRPTY UND CPTL LSS-O	142794	FIN LEASE ROU ASSETS (COST)-OTHER-TEM	OR	3,146	-	3,146	-	-	-	-	-	-
1011900	PRPTY UND CPTL LSS-O	142794	FIN LEASE ROU ASSETS (COST)-OTHER-TEM	SG	4,793	66	1,288	359	660	2,151	268	0	-
1011900 Total					**7,939**	**66**	**4,434**	**359**	**660**	**2,151**	**268**	**0**	**-**
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)	(66)	(1,288)	(359)	(660)	(2,151)	(268)	(0)	-
1011950 Total					**(7,939)**	**(66)**	**(4,434)**	**(359)**	**(660)**	**(2,151)**	**(268)**	**(0)**	**-**
Grand Total					**8,749**	**111**	**2,858**	**603**	**1,110**	**3,617**	**451**	**0**	**-**

B10.PLANT HELD FOR FUTURE USE

PACIFICORP

Plant Held for Future Use (Actuals)
Year End: 06/2023
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	3501000	LAND OWNED IN FEE	SG	1,358	19	365	102	187	609	76	0	-
1050000	EL PLT HLD FTR USE	3502000	LAND RIGHTS	SG	755	10	203	57	104	339	42	0	-
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	5,168	-	-	-	-	5,168	-	-	-
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					**14,175**	**29**	**7,461**	**158**	**292**	**6,116**	**118**	**0**	**-**
Grand Total					**14,175**	**29**	**7,461**	**158**	**292**	**6,116**	**118**	**0**	**-**

B11. MISC. DEFERRED DEBITS

PACIFICORP

Deferred Debits (Actuals)
Year End: 06/2023
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	30	618	160	349	1,049	141	0	-
1861000	MS DEF DB-OTH WIP	185017	ERCs - Impairment Reserve	SE	(2,040)	(26)	(537)	(139)	(303)	(912)	(123)	(0)	-
1861000 Total					**307**	**4**	**81**	**21**	**46**	**137**	**18**	**0**	**-**
1861200	FINANCING COSTS DEFR	185027	UNAMORTIZED CREDIT AGREEMENT COSTS	OTHER	3,197	-	-	-	-	-	-	-	3,197
1861200	FINANCING COSTS DEFR	185029	UNAMORTIZED PCRB MADE CONVERSION COSTS	OTHER	118	-	-	-	-	-	-	-	118
1861200	FINANCING COSTS DEFR	185030	UNAMORTIZED '94 SERIES RESTRUCTURING COS	OTHER	78	-	-	-	-	-	-	-	78
1861200 Total					**3,393**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**3,393**
1868000	MISC DF DR-OTH-CST	134305	Oth Def Chrg - IT Licenses/Maintenance	OTHER	34	-	-	-	-	-	-	-	34
1868000	MISC DF DR-OTH-CST	185336	BOGUS CREEK	SG	685	9	184	51	94	307	38	0	-
1868000	MISC DF DR-OTH-CST	185337	POINT-TO-POINT TRANS RESERVATIONS	SG	10,536	145	2,832	789	1,451	4,728	589	0	-
1868000	MISC DF DR-OTH-CST	185359	LT Lake Side 2 Maint. Prepayment	SG	33,050	455	8,885	2,475	4,553	14,833	1,849	0	-
1868000	MISC DF DR-OTH-CST	185360	LT LAKE SIDE MAINT PREPAYMENT	SG	24,824	342	6,674	1,859	3,420	11,141	1,389	0	-
1868000	MISC DF DR-OTH-CST	185361	LT CHEHALIS CSA MAINT. PREPAYMENT	SG	10,641	147	2,861	797	1,466	4,776	595	0	-
1868000	MISC DF DR-OTH-CST	185362	LT Currant Creek CSA Maint Prepayment	SG	10,553	145	2,837	790	1,454	4,736	590	0	-
1868000	MISC DF DR-OTH-CST	185371	LT Chehalis CSA Prepaid O&M	SG	1,641	23	441	123	226	736	92	0	-
1868000	MISC DF DR-OTH-CST	185372	LT Currant Creek CSA Prepaid O&M	SG	421	6	113	31	58	189	24	0	-
1868000	MISC DF DR-OTH-CST	185400	Trans Readiness Security - Due to ESM	SG	28,026	386	7,535	2,099	3,861	12,578	1,568	0	-
1868000	MISC DF DR-OTH-CST	185401	Trans Readiness Security - ESM Rec	SG	(28,026)	(386)	(7,535)	(2,099)	(3,861)	(12,578)	(1,568)	(0)	-
1868000	MISC DF DR-OTH-CST	185402	Trans Sec - Site Control - Due to ESM	SG	30	0	8	2	4	13	2	0	-
1868000	MISC DF DR-OTH-CST	185403	Trans Sec - Site Control - ESM Rec	SG	(30)	(0)	(8)	(2)	(4)	(13)	(2)	(0)	-
1868000	MISC DF DR-OTH-CST	185551	LT Prepaid-FSA Capital - Dunlap	SG	4,478	62	1,204	335	617	2,010	250	0	-
1868000	MISC DF DR-OTH-CST	185552	LT Prepaid-FSA Capital - Ekola Flats	SG	4,134	57	1,111	310	570	1,855	231	0	-
1868000	MISC DF DR-OTH-CST	185554	LT Prepaid-FSA Capital - Foote Creek	SG	1,005	14	270	75	138	451	56	0	-
1868000	MISC DF DR-OTH-CST	185557	LT Prepaid-FSA Capital - Glenrock I	SG	4,271	59	1,148	320	588	1,917	239	0	-
1868000	MISC DF DR-OTH-CST	185558	LT Prepaid-FSA Capital - Glenrock III	SG	1,778	24	478	133	245	798	99	0	-
1868000	MISC DF DR-OTH-CST	185561	LT Prepaid-FSA Capital - Goodnoe Hills	SG	3,968	55	1,067	297	547	1,781	222	0	-
1868000	MISC DF DR-OTH-CST	185564	LT Prepaid-FSA Capital - High Plains	SG	3,877	53	1,042	290	534	1,740	217	0	-
1868000	MISC DF DR-OTH-CST	185567	LT Prepaid-FSA Capital - Leaning Juniper	SG	4,517	62	1,214	338	622	2,027	253	0	-
1868000	MISC DF DR-OTH-CST	185570	LT Prepaid-FSA Capital - Marengo I	SG	5,933	82	1,595	444	817	2,663	332	0	-
1868000	MISC DF DR-OTH-CST	185571	LT Prepaid-FSA Capital - Marengo II	SG	2,949	41	793	221	406	1,324	165	0	-
1868000	MISC DF DR-OTH-CST	185574	LT Prepaid-FSA Capital - McFadden Ridge	SG	1,474	20	396	110	203	661	82	0	-
1868000	MISC DF DR-OTH-CST	185576	LT Prepaid-FSA Capital - Pryor Mtn	SG	6,431	89	1,729	482	886	2,886	360	0	-
1868000	MISC DF DR-OTH-CST	185577	LT Prepaid-FSA Capital - Rolling Hills	SG	4,031	56	1,084	302	555	1,809	226	0	-
1868000	MISC DF DR-OTH-CST	185580	LT Prepaid-FSA Capital - Seven Mile I	SG	4,241	58	1,140	318	584	1,903	237	0	-
1868000	MISC DF DR-OTH-CST	185581	LT Prepaid-FSA Capital - Seven Mile II	SG	975	13	262	73	134	438	55	0	-
1868000	MISC DF DR-OTH-CST	185584	LT Prepaid-FSA Capital - TB Flats I	SG	3,247	45	873	243	447	1,457	182	0	-
1868000	MISC DF DR-OTH-CST	185585	LT Prepaid-FSA Capital - TB Flats II	SG	3,601	50	968	270	496	1,616	201	0	-
1868000 Total					**153,294**	**2,110**	**41,203**	**11,476**	**21,113**	**68,783**	**8,574**	**0**	**34**
1869000	MISC DF DR-OTH-NC	185334	HERMISTON SWAP	SG	2,246	31	604	168	309	1,008	126	0	-
1869000 Total					**2,246**	**31**	**604**	**168**	**309**	**1,008**	**126**	**0**	**-**
Grand Total					**159,240**	**2,145**	**41,887**	**11,666**	**21,468**	**69,929**	**8,718**	**0**	**3,427**

B12. BLANK

B13. MATERIALS & SUPPLIES

PACIFICORP

Material & Supplies (Actuals)
Year End: 06/2023
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	24,158	307	6,363	1,648	3,589	10,798	1,453	0	-
1511120 Total					**24,158**	**307**	**6,363**	**1,648**	**3,589**	**10,798**	**1,453**	**0**	**-**
1511130	COAL INVNTRY-HTG	0	COAL INVENTORY - HUNTINGTON	SE	22,464	286	5,917	1,532	3,338	10,041	1,351	0	-
1511130 Total					**22,464**	**286**	**5,917**	**1,532**	**3,338**	**10,041**	**1,351**	**0**	**-**
1511140	COAL INVNTRY-JB	0	COAL INVENTORY - JIM BRIDGER	SE	36,658	466	9,655	2,500	5,447	16,385	2,205	0	-
1511140 Total					**36,658**	**466**	**9,655**	**2,500**	**5,447**	**16,385**	**2,205**	**0**	**-**
1511160	COAL INVNTRY-NAU	0	COAL INVENTORY - NAUGHTON	SE	21,630	275	5,697	1,475	3,214	9,668	1,301	0	-
1511160 Total					**21,630**	**275**	**5,697**	**1,475**	**3,214**	**9,668**	**1,301**	**0**	**-**
1511300	COAL INVNTRY-COLSTRI	0	COAL INVENTORY - COLSTIP	SE	2,093	27	551	143	311	935	126	0	-
1511300 Total					**2,093**	**27**	**551**	**143**	**311**	**935**	**126**	**0**	**-**
1511400	COAL INVNTRY-CRAIG	0	COAL INVENTORY - CRAIG	SE	7,582	96	1,997	517	1,127	3,389	456	0	-
1511400 Total					**7,582**	**96**	**1,997**	**517**	**1,127**	**3,389**	**456**	**0**	**-**
1511600	COAL INVNTRY-DJ	0	COAL INVENTORY - DAVE JOHNSTON	SE	15,026	191	3,958	1,025	2,233	6,716	904	0	-
1511600 Total					**15,026**	**191**	**3,958**	**1,025**	**2,233**	**6,716**	**904**	**0**	**-**
1511700	COAL INVNTRY-RG	0	COAL INVENTORY ROCK GARDEN PILE	SE	4,698	60	1,237	320	698	2,100	283	0	-
1511700 Total					**4,698**	**60**	**1,237**	**320**	**698**	**2,100**	**283**	**0**	**-**
1511900	COAL INVNTRY-HAYDEN	0	COAL INVENTORY - HAYDEN	SE	2,645	34	697	180	393	1,182	159	0	-
1511900 Total					**2,645**	**34**	**697**	**180**	**393**	**1,182**	**159**	**0**	**-**
1512180	NATURAL GAS-CLAY BAS	0	NATURAL GAS - CLAY BASIN	SE	1,783	23	470	122	265	797	107	0	-
1512180 Total					**1,783**	**23**	**470**	**122**	**265**	**797**	**107**	**0**	**-**
1514000	FUEL STK-FUEL OIL	0	FUEL STOCK COAL MINE	SE	3,282	42	865	224	488	1,467	197	0	-
1514000 Total					**3,282**	**42**	**865**	**224**	**488**	**1,467**	**197**	**0**	**-**
1514300	OIL INVNTRY-COLSTRIP	0	OIL INVENTORY - COLSTRIP	SE	103	1	27	7	15	46	6	0	-
1514300 Total					**103**	**1**	**27**	**7**	**15**	**46**	**6**	**0**	**-**
1514400	OIL INVENTORY-CRAIG	0	OIL INVENTORY - CRAIG	SE	37	0	10	3	5	16	2	0	-
1514400 Total					**37**	**0**	**10**	**3**	**5**	**16**	**2**	**0**	**-**
1514900	OIL INVENTORY-HAYDEN	0	OIL INVENTORY - HAYDEN	SE	13	0	3	1	2	6	1	0	-
1514900 Total					**13**	**0**	**3**	**1**	**2**	**6**	**1**	**0**	**-**
1541000	PLNT M&S STK CNTRL	0	MATERIAL CONTROL ADJUST	SO	(148)	(4)	(41)	(11)	(19)	(66)	(8)	(0)	-
1541000	PLNT M&S STK CNTRL	1510	JIM BRIDGER STORE ROOM	SG	25,966	358	6,981	1,944	3,577	11,653	1,453	0	-
1541000	PLNT M&S STK CNTRL	1515	DAVE JOHNSTON STORE ROOM	SG	21,602	297	5,808	1,618	2,976	9,695	1,208	0	-
1541000	PLNT M&S STK CNTRL	1520	WYODAK STORE ROOM	SG	7,090	98	1,906	531	977	3,182	397	0	-
1541000	PLNT M&S STK CNTRL	1525	GADSBY STORE ROOM	SG	4,499	62	1,209	337	620	2,019	252	0	-
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	13,975	192	3,757	1,046	1,925	6,272	782	0	-
1541000	PLNT M&S STK CNTRL	1540	HUNTINGTON STORE ROOM	SG	21,660	298	5,823	1,622	2,984	9,721	1,212	0	-
1541000	PLNT M&S STK CNTRL	1545	HUNTER STORE ROOM	SG	31,265	430	8,405	2,341	4,307	14,032	1,749	0	-
1541000	PLNT M&S STK CNTRL	1550	BLUNDELL STORE ROOM	SG	1,227	17	330	92	169	551	69	0	-
1541000	PLNT M&S STK CNTRL	1565	CURRANT CREEK PLANT	SG	4,116	57	1,107	308	567	1,847	230	0	-
1541000	PLNT M&S STK CNTRL	1570	LAKESIDE PLANT	SG	6,942	96	1,866	520	956	3,115	388	0	-
1541000	PLNT M&S STK CNTRL	1580	CHEHALIS PLANT	SG	3,856	53	1,037	289	531	1,730	216	0	-
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	29	0	8	2	4	13	2	0	-
1541000	PLNT M&S STK CNTRL	1700	LEANING JUNIPER STOREROOM	SG	318	4	85	24	44	143	18	0	-
1541000	PLNT M&S STK CNTRL	1705	GOODNOE HILLS WIND	SG	116	2	31	9	16	52	7	0	-
1541000	PLNT M&S STK CNTRL	1715	MARENGO WIND	SG	235	3	63	18	32	105	13	0	-
1541000	PLNT M&S STK CNTRL	1720	Foote Creek	SG	5	0	1	0	1	2	0	0	-
1541000	PLNT M&S STK CNTRL	1725	Glenrock/Rolling Hills	SG	1,012	14	272	76	139	454	57	0	-
1541000	PLNT M&S STK CNTRL	1730	Seven Mile Hill	SG	485	7	130	36	67	218	27	0	-

PACIFICORP

Material & Supplies (Actuals)
Year End: 06/2023
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	1735	Ekola Flats	SG	5	0	1	0	1	2	0	0	-
1541000	PLNT M&S STK CNTRL	1740	High Plains/McFadden	SG	352	5	95	26	49	158	20	0	-
1541000	PLNT M&S STK CNTRL	1745	Dunlap Wind Project	SG	444	6	119	33	61	199	25	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	940	13	253	70	129	422	53	0	-
1541000	PLNT M&S STK CNTRL	1765	Pryor Mountain	SG	8	0	2	1	1	4	0	0	-
1541000	PLNT M&S STK CNTRL	2005	CASPER STORE ROOM	WYP	804	-	-	-	804	-	-	-	-
1541000	PLNT M&S STK CNTRL	2010	BUFFALO STORE ROOM	WYP	163	-	-	-	163	-	-	-	-
1541000	PLNT M&S STK CNTRL	2015	DOUGLAS STORE ROOM	WYP	360	-	-	-	360	-	-	-	-
1541000	PLNT M&S STK CNTRL	2020	CODY STORE ROOM	WYP	1,016	-	-	-	1,016	-	-	-	-
1541000	PLNT M&S STK CNTRL	2030	WORLAND STORE ROOM	WYP	1,027	-	-	-	1,027	-	-	-	-
1541000	PLNT M&S STK CNTRL	2035	RIVERTON STORE ROOM	WYP	669	-	-	-	669	-	-	-	-
1541000	PLNT M&S STK CNTRL	2040	EVANSTON STORE ROOM	WYU	1,336	-	-	-	1,336	-	-	-	-
1541000	PLNT M&S STK CNTRL	2045	KEMMERER STORE ROOM	WYU	13	-	-	-	13	-	-	-	-
1541000	PLNT M&S STK CNTRL	2050	PINEDALE STORE ROOM	WYU	948	-	-	-	948	-	-	-	-
1541000	PLNT M&S STK CNTRL	2060	ROCK SPRINGS STORE ROOM	WYP	1,909	-	-	-	1,909	-	-	-	-
1541000	PLNT M&S STK CNTRL	2065	RAWLINS STORE ROOM	WYP	653	-	-	-	653	-	-	-	-
1541000	PLNT M&S STK CNTRL	2070	LARAMIE STORE ROOM	WYP	754	-	-	-	754	-	-	-	-
1541000	PLNT M&S STK CNTRL	2075	REXBERG STORE ROOM	IDU	2,885	-	-	-	-	-	2,885	-	-
1541000	PLNT M&S STK CNTRL	2080	MUDLAKE STORE ROOM	IDU	1	-	-	-	-	-	1	-	-
1541000	PLNT M&S STK CNTRL	2085	SHELLY STORE ROOM	IDU	1,567	-	-	-	-	-	1,567	-	-
1541000	PLNT M&S STK CNTRL	2090	PRESTON STORE ROOM	IDU	93	-	-	-	-	-	93	-	-
1541000	PLNT M&S STK CNTRL	2095	LAVA HOT SPRINGS STORE ROOM	IDU	312	-	-	-	-	-	312	-	-
1541000	PLNT M&S STK CNTRL	2100	MONTPELIER STORE ROOM	IDU	366	-	-	-	-	-	366	-	-
1541000	PLNT M&S STK CNTRL	2110	BRIDGERLAND STORE ROOM	UT	1,562	-	-	-	-	1,562	-	-	-
1541000	PLNT M&S STK CNTRL	2205	TREMONTON STORE ROOM	UT	671	-	-	-	-	671	-	-	-
1541000	PLNT M&S STK CNTRL	2210	OGDEN STORE ROOM	UT	2,806	-	-	-	-	2,806	-	-	-
1541000	PLNT M&S STK CNTRL	2215	LAYTON STORE ROOM	UT	2,353	-	-	-	-	2,353	-	-	-
1541000	PLNT M&S STK CNTRL	2220	SALT LAKE METRO STORE ROOM	UT	11,527	-	-	-	-	11,527	-	-	-
1541000	PLNT M&S STK CNTRL	2230	JORDAN VALLEY STORE ROOM	UT	1,415	-	-	-	-	1,415	-	-	-
1541000	PLNT M&S STK CNTRL	2235	PARK CITY STORE ROOM	UT	2,648	-	-	-	-	2,648	-	-	-
1541000	PLNT M&S STK CNTRL	2240	TOOELE STORE ROOM	UT	1,043	-	-	-	-	1,043	-	-	-
1541000	PLNT M&S STK CNTRL	2245	WASATCH RESTORATION CENTER	UT	1,800	-	-	-	-	1,800	-	-	-
1541000	PLNT M&S STK CNTRL	2400	PLNT M&S STK CNTRL EAGLE MOUNTAIN	UT	1,013	-	-	-	-	1,013	-	-	-
1541000	PLNT M&S STK CNTRL	2405	AMERICAN FORK STORE ROOM	UT	2,555	-	-	-	-	2,555	-	-	-
1541000	PLNT M&S STK CNTRL	2410	SANTAQUIN STORE ROOM	UT	1,991	-	-	-	-	1,991	-	-	-
1541000	PLNT M&S STK CNTRL	2415	DELTA STORE ROOM	UT	456	-	-	-	-	456	-	-	-
1541000	PLNT M&S STK CNTRL	2420	VERNAL STORE ROOM	UT	1,124	-	-	-	-	1,124	-	-	-
1541000	PLNT M&S STK CNTRL	2425	PRICE STORE ROOM	UT	949	-	-	-	-	949	-	-	-
1541000	PLNT M&S STK CNTRL	2430	MOAB STORE ROOM	UT	1,376	-	-	-	-	1,376	-	-	-
1541000	PLNT M&S STK CNTRL	2435	BLANDING STORE ROOM	UT	112	-	-	-	-	112	-	-	-
1541000	PLNT M&S STK CNTRL	2445	RICHFIELD STORE ROOM	UT	141	-	-	-	-	141	-	-	-
1541000	PLNT M&S STK CNTRL	2450	CEDAR CITY STORE ROOM	UT	2,881	-	-	-	-	2,881	-	-	-
1541000	PLNT M&S STK CNTRL	2455	MILFORD STORE ROOM	UT	14	-	-	-	-	14	-	-	-
1541000	PLNT M&S STK CNTRL	2460	WASHINGTON STORE ROOM	UT	1,049	-	-	-	-	1,049	-	-	-
1541000	PLNT M&S STK CNTRL	2620	WALLA WALLA STORE ROOM	WA	2,633	-	-	2,633	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	2630	YAKIMA STORE ROOM	WA	474	-	-	474	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	2635	ENTERPRISE STORE ROOM	OR	229	-	229	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	2640	PENDLETON STORE ROOM	OR	1,188	-	1,188	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	2650	HOOD RIVER STORE ROOM	OR	661	-	661	-	-	-	-	-	-

PACIFICORP

Material & Supplies (Actuals)
Year End: 06/2023
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	2655	PORTLAND METRO - STORE ROOM	OR	17,015	-	17,015	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	2660	ASTORIA STORE ROOM	OR	1,659	-	1,659	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	2665	MADRAS STORE ROOM	OR	116	-	116	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	2670	PRINEVILLE STORE ROOM	OR	1	-	1	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	2675	BEND STORE ROOM	OR	3,741	-	3,741	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	2805	ALBANY STORE ROOM	OR	303	-	303	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	2810	LINCOLN CITY STORE ROOM	OR	255	-	255	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	2830	ROSEBURG STORE ROOM	OR	4,929	-	4,929	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	2835	COOS BAY STORE ROOM	OR	1,144	-	1,144	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	2840	GRANTS PASS STORE ROOM	OR	1,867	-	1,867	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	2845	MEDFORD STORE ROOM	OR	938	-	938	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	2850	KLAMATH FALLS STORE ROOM	OR	3,513	-	3,513	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	2855	LAKEVIEW STORE ROOM	OR	144	-	144	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	2860	ALTURAS STORE ROOM	CA	100	100	-	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	2865	MT SHASTA STORE ROOM	CA	369	369	-	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	2870	YREKA STORE ROOM	CA	1,758	1,758	-	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	2875	CRESENT CITY STORE ROOM	CA	579	579	-	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	5005	TREMONTON STORE ROOM	SO	146	4	40	11	19	65	8	0	-
1541000	PLNT M&S STK CNTRL	5110	MATERIAL PACKAGING CENTER - WEST	OR	0	-	0	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	5115	DEMC - SLC	SNPD	179	12	45	10	15	87	9	-	-
1541000	PLNT M&S STK CNTRL	5120	DEMC - MEDFORD	OR	173	-	173	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	5125	DEMC - OREGON	OR	18,630	-	18,630	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	5130	MEDFORD HUB	OR	35,606	-	35,606	-	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	5135	YAKIMA HUB	WA	15,820	-	-	15,820	-	-	-	-	-
1541000	PLNT M&S STK CNTRL	5140	PRESTON HUB	IDU	9,399	-	-	-	-	-	9,399	-	-
1541000	PLNT M&S STK CNTRL	5150	RICHFIELD HUB	UT	10,274	-	-	-	-	10,274	-	-	-
1541000	PLNT M&S STK CNTRL	5155	CASPER HUB	WYP	8,843	-	-	-	8,843	-	-	-	-
1541000	PLNT M&S STK CNTRL	5160	SALT LAKE METRO HUB	UT	53,964	-	-	-	-	53,964	-	-	-
1541000	PLNT M&S STK CNTRL	5300	METER TEST WAREHOUSE	UT	3	-	-	-	-	3	-	-	-
1541000 Total					**397,028**	**4,831**	**131,449**	**29,882**	**38,647**	**169,410**	**22,810**	**0**	**-**
1541500	OTHER M&S	0	M&S GLENROCK COAL MINE	SE	198	3	52	13	29	88	12	0	-
1541500	OTHER M&S	120001	OTHER MATERIAL & SUPPLIES - GENERAL STOC	SE	(198)	(3)	(52)	(13)	(29)	(88)	(12)	(0)	-
1541500	OTHER M&S	120001	OTHER MATERIAL & SUPPLIES - GENERAL STOC	SO	597	16	164	44	76	266	33	0	-
1541500 Total					**597**	**16**	**164**	**44**	**76**	**266**	**33**	**0**	**-**
1541900	PLNT M&S GEN JV CUT	120005	JV CUTBACK MATERIAL & SUPPLIES INVENTORY	SG	(8,694)	(120)	(2,337)	(651)	(1,198)	(3,902)	(486)	(0)	-
1541900	PLNT M&S GEN JV CUT	120005	JV CUTBACK MATERIAL & SUPPLIES INVENTORY	SO	(1,380)	(36)	(378)	(101)	(175)	(613)	(75)	(0)	-
1541900	PLNT M&S GEN JV CUT	120010	Minority Owned Plant M&S Inventory	SG	5,311	73	1,428	398	732	2,384	297	0	-
1541900 Total					**(4,762)**	**(83)**	**(1,288)**	**(354)**	**(641)**	**(2,131)**	**(264)**	**(0)**	**-**
1549900	CR-OBSOL&SURPL INV	102930	SB Asset # 120930	SO	(27)	(1)	(8)	(2)	(3)	(12)	(1)	(0)	-
1549900	CR-OBSOL&SURPL INV	120930	INVENTORY RESERVE POWER SUPPLY	SG	(166)	(2)	(44)	(12)	(23)	(74)	(9)	(0)	-
1549900	CR-OBSOL&SURPL INV	120930	INVENTORY RESERVE POWER SUPPLY	SO	(12)	(0)	(3)	(1)	(2)	(6)	(1)	(0)	-
1549900	CR-OBSOL&SURPL INV	120932	Inventory Reserve - RMP (T&D)	SNPD	(1,038)	(70)	(259)	(60)	(89)	(507)	(51)	-	-
1549900	CR-OBSOL&SURPL INV	120933	Inventory Reserve - PP (T&D)	SNPD	(460)	(31)	(115)	(27)	(40)	(225)	(23)	-	-
1549900 Total					**(1,703)**	**(104)**	**(430)**	**(102)**	**(157)**	**(825)**	**(86)**	**(0)**	**-**
1581200	WA GHG ALLOWANCE INV	0	WA GHG ALLOWANCE INVENTORY	OTHER	16,243	-	-	-	-	-	-	-	16,243
1581200 Total					**16,243**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**16,243**
2531600	WORK CAP DEP-UAMPS	289920	WORKING CAPITAL DEPOSIT - UAMPS	SE	(1,762)	(22)	(464)	(120)	(262)	(788)	(106)	(0)	-
2531600 Total					**(1,762)**	**(22)**	**(464)**	**(120)**	**(262)**	**(788)**	**(106)**	**(0)**	**-**
2531700	WORKG CAP DEP-DG&T	289921	OTH DEF CR - WORKING CAPITAL DEPOS-DG&T	SE	(2,803)	(36)	(738)	(191)	(416)	(1,253)	(169)	(0)	-

Material & Supplies (Actuals)
Year End: 06/2023
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
2531700 Total					**(2,803)**	**(36)**	**(738)**	**(191)**	**(416)**	**(1,253)**	**(169)**	**(0)**	**-**
2531800	WCD-PROVO-PLNT M&S	289922	OTH DEF CR - WCD - PROVO - PLANT M&S	SG	(273)	(4)	(73)	(20)	(38)	(123)	(15)	(0)	-
2531800 Total					**(273)**	**(4)**	**(73)**	**(20)**	**(38)**	**(123)**	**(15)**	**(0)**	**-**
Grand Total					**544,735**	**6,404**	**166,066**	**38,834**	**58,333**	**228,102**	**30,754**	**0**	**16,243**

B14. CASH WORKING CAPITAL

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Cash Working Capital (Actuals)
12 Month Average: 06/2023
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	21,728	570	5,959	1,590	2,763	9,661	1,185	0	-
1430000 Total					**21,728**	**570**	**5,959**	**1,590**	**2,763**	**9,661**	**1,185**	**0**	**-**
1431000	EMP ACCOUNTS REC	0	EMPLOYEE RECEIVABLES	SO	4,636	122	1,272	339	590	2,062	253	0	-
1431000 Total					**4,636**	**122**	**1,272**	**339**	**590**	**2,062**	**253**	**0**	**-**
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	289	8	79	21	37	128	16	0	-
1431500	INC TAXES RECEIVABLE	116134	InterCo State Tax Rec -(Odd Years)- MEHC	SO	(57)	(2)	(16)	(4)	(7)	(25)	(3)	(0)	-
1431500 Total					**161**	**4**	**44**	**12**	**20**	**72**	**9**	**0**	**-**
1433000	JOINT OWNER REC	0	JOINT OWNER RECEIVABLE	SO	2,455	64	673	180	312	1,092	134	0	-
1433000 Total					**2,455**	**64**	**673**	**180**	**312**	**1,092**	**134**	**0**	**-**
1436000	OTH ACCT REC	0	OTHER ACCOUNTS RECEIVABLE	SO	50,207	1,317	13,770	3,673	6,385	22,324	2,737	0	-
1436000 Total					**50,207**	**1,317**	**13,770**	**3,673**	**6,385**	**22,324**	**2,737**	**0**	**-**
1437000	CSS OAR BILLINGS	0	CSS OAR BILLINGS	SO	8,829	232	2,421	646	1,123	3,926	481	0	-
1437000 Total					**8,829**	**232**	**2,421**	**646**	**1,123**	**3,926**	**481**	**0**	**-**
1437100	CSS OAR BILLINGS-WOR	0	OTHER ACCT REC CCS	SO	(20,441)	(536)	(5,606)	(1,496)	(2,600)	(9,089)	(1,115)	(0)	-
1437100 Total					**(20,441)**	**(536)**	**(5,606)**	**(1,496)**	**(2,600)**	**(9,089)**	**(1,115)**	**(0)**	**-**
2300000	ASSET RETIREMENT OBL	284915	ARO LIAB - DEER CREEK MINE RECLAMATION	OTHER	(2,023)	-	-	-	-	-	-	-	(2,023)
2300000 Total					**(2,023)**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**(2,023)**
2320000	ACCOUNTS PAYABLE	210460	JOINT OWNER RECEIVABLES - CREDIT	SE	(859)	(11)	(226)	(59)	(128)	(384)	(52)	(0)	-
2320000	ACCOUNTS PAYABLE	210677	Bronco Utah Operations LLC - Coal	SE	(1,819)	(23)	(479)	(124)	(270)	(813)	(109)	(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	(4)	(0)	(1)	(0)	(1)	(2)	(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	(8)	(0)	(2)	(1)	(1)	(4)	(0)	(0)	-
2320000	ACCOUNTS PAYABLE	215077	K-PLUS EMPLOYER CONTRIBUTIONS - ENHANCED	SO	(568)	(15)	(156)	(42)	(72)	(253)	(31)	(0)	-
2320000	ACCOUNTS PAYABLE	215078	K-Plus Employer Contributions - Fixed	SO	(97)	(3)	(27)	(7)	(12)	(43)	(5)	(0)	-
2320000	ACCOUNTS PAYABLE	215080	METLIFE MEDICAL INSURANCE	SO	(4,168)	(109)	(1,143)	(305)	(530)	(1,853)	(227)	(0)	-
2320000	ACCOUNTS PAYABLE	215082	METLIFE DENTAL INSURANCE	SO	(57)	(1)	(16)	(4)	(7)	(25)	(3)	(0)	-
2320000	ACCOUNTS PAYABLE	215084	METLIFE VISION INSURANCE	SO	(163)	(4)	(45)	(12)	(21)	(72)	(9)	(0)	-
2320000	ACCOUNTS PAYABLE	215085	Western Utilities Dental Payable	SO	60	2	16	4	8	27	3	0	-
2320000	ACCOUNTS PAYABLE	215086	Western Utilities Vision Payable	SO	8	0	2	1	1	3	0	0	-
2320000	ACCOUNTS PAYABLE	215088	UWUA Health & Welfare Payable	SO	0	0	0	0	0	0	0	0	-
2320000	ACCOUNTS PAYABLE	215095	HMO HEALTH PLAN	SO	(19)	(0)	(5)	(1)	(2)	(8)	(1)	(0)	-
2320000	ACCOUNTS PAYABLE	215103	Bluegrass Coal Purchases	SE	(77)	(1)	(20)	(5)	(11)	(34)	(5)	(0)	-
2320000	ACCOUNTS PAYABLE	215112	Minnesota Life Insurance	SO	(19)	(1)	(5)	(1)	(2)	(9)	(1)	(0)	-
2320000	ACCOUNTS PAYABLE	215116	IBEW 57 MEDICAL INSURANCE	SO	(445)	(12)	(122)	(33)	(57)	(198)	(24)	(0)	-
2320000	ACCOUNTS PAYABLE	215350	"IBEW 57 HEALTH REIMBURSEMENT, CURRENT Y	SO	3	0	1	0	0	1	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	(34)	(1)	(9)	(2)	(4)	(15)	(2)	(0)	-
2320000	ACCOUNTS PAYABLE	215357	"DEPENDENT CARE REIMBURSEMENT, CURRENT Y	SO	(16)	(0)	(4)	(1)	(2)	(7)	(1)	(0)	-
2320000	ACCOUNTS PAYABLE	215425	OR DOE Cool School Program	OTHER	(19)	-	-	-	-	-	-	-	(19)
2320000	ACCOUNTS PAYABLE	215439	Cal ISO Trans Payable	SG	(4,622)	(64)	(1,243)	(346)	(637)	(2,074)	(259)	(0)	-
2320000	ACCOUNTS PAYABLE	215850	Subscription Fee - OR Community Solar	OTHER	(5)	-	-	-	-	-	-	-	(5)
2320000	ACCOUNTS PAYABLE	215851	Participation Fee - OR Community Solar	OTHER	(0)	-	-	-	-	-	-	-	(0)
2320000	ACCOUNTS PAYABLE	235230	ACCRUAL - ROYALTIES	SE	(61)	(1)	(16)	(4)	(9)	(27)	(4)	(0)	-
2320000	ACCOUNTS PAYABLE	235599	Safety Award	SO	(1,017)	(27)	(279)	(74)	(129)	(452)	(55)	(0)	-
2320000	ACCOUNTS PAYABLE	240330	PROVISION FOR WORKERS' COMPENSATION	SO	83	2	23	6	11	37	5	0	-
2320000 Total					**(13,924)**	**(269)**	**(3,756)**	**(1,011)**	**(1,877)**	**(6,206)**	**(780)**	**(0)**	**(24)**

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Cash Working Capital (Actuals)
12 Month Average: 06/2023
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
2533000	O DEF CR-MISC PPL	289517	TRAPPER MINE FINAL RECLAMATION	SE	(10,816)	(137)	(2,849)	(738)	(1,607)	(4,834)	(651)	(0)	-
2533000 Total					**(10,816)**	**(137)**	**(2,849)**	**(738)**	**(1,607)**	**(4,834)**	**(651)**	**(0)**	**-**
Grand Total					**40,813**	**1,366**	**11,928**	**3,195**	**5,110**	**19,007**	**2,254**	**(0)**	**(2,047)**

B15. MISC. RATE BASE

Miscellaneous Rate Base (Actuals)
Year End: 06/2023
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	1,992	38,903	10,836	19,935	64,944	8,095	0	-
1140000	EL PLT ACQUIST ADJ	1140000	ELECTRIC PLANT ACQUISITION ADJUSTMENTS	UT	11,764	-	-	-	-	11,764	-	-	-
1140000 Total					**156,468**	**1,992**	**38,903**	**10,836**	**19,935**	**76,708**	**8,095**	**0**	**-**
1150000	Ac Prov El Pt Acq Ad	1140000	ACCUM PROV ELECTRIC PLANT ACQUISITION AD	SG	(142,014)	(1,955)	(38,179)	(10,634)	(19,564)	(63,736)	(7,945)	(0)	-
1150000	Ac Prov El Pt Acq Ad	1140000	ACCUM PROV ELECTRIC PLANT ACQUISITION AD	UT	(2,501)	-	-	-	-	(2,501)	-	-	-
1150000 Total					**(144,514)**	**(1,955)**	**(38,179)**	**(10,634)**	**(19,564)**	**(66,237)**	**(7,945)**	**(0)**	**-**
1281000	Oth Special Funds-Pn	0	Other special funds - Pensions	SO	104,951	2,753	28,783	7,679	13,347	46,666	5,722	0	-
1281000 Total					**104,951**	**2,753**	**28,783**	**7,679**	**13,347**	**46,666**	**5,722**	**0**	**-**
1651000	PREPAY-INSURANCE	132008	PREPAID INSURANCE - PUBLIC LIABILITY & P	SO	4,199	110	1,152	307	534	1,867	229	0	-
1651000	PREPAY-INSURANCE	132012	PREPAID INSURANCE - ALLPURPOSE INSURANCE	SO	567	15	155	41	72	252	31	0	-
1651000	PREPAY-INSURANCE	132016	PREPAID INS-MINORITY OWNED PLANTS	SO	783	21	215	57	100	348	43	0	-
1651000	PREPAY-INSURANCE	132045	PREPAID WORKERS COMPENSATION	SO	409	11	112	30	52	182	22	0	-
1651000	PREPAY-INSURANCE	132055	PREPAID EMPLOYEE BENEFIT COSTS	SO	34	1	9	3	4	15	2	0	-
1651000 Total					**5,991**	**157**	**1,643**	**438**	**762**	**2,664**	**327**	**0**	**-**
1652000	PREPAY-TAXES	132109	UTE-PREPAID POSSESSORY INTEREST	GPS	23	1	6	2	3	10	1	0	-
1652000	PREPAY-TAXES	132110	SHO-BAN-PREPAID POSSESSORY INTEREST	GPS	149	4	41	11	19	66	8	0	-
1652000	PREPAY-TAXES	132111	Goshute - Prepaid Possessory Interest	GPS	15	0	4	1	2	7	1	0	-
1652000	PREPAY-TAXES	132200	"Prepaid Taxes (Federal, State, Local)"	SO	29	1	8	2	4	13	2	0	-
1652000 Total					**216**	**6**	**59**	**16**	**27**	**96**	**12**	**0**	**-**
1652100	PREPAY - OTHER	132097	Prepaid CA GHG Cap & Trade Allowances	OTHE	3,922	-	-	-	-	-	-	-	3,922
1652100	PREPAY - OTHER	132098	Prepaid - CA GHG Wholesale	OTHE	2,400	-	-	-	-	-	-	-	2,400
1652100	PREPAY - OTHER	132310	PREPAID RATING AGNCY	SO	47	1	13	3	6	21	3	0	-
1652100	PREPAY - OTHER	132548	Prepaid-FSA O&M - Cedar Springs II	SG	507	7	136	38	70	228	28	0	-
1652100	PREPAY - OTHER	132551	Prepaid-FSA O&M - Dunlap	SG	208	3	56	16	29	93	12	0	-
1652100	PREPAY - OTHER	132552	Prepaid-FSA O&M - Ekola Flats	SG	331	5	89	25	46	149	19	0	-
1652100	PREPAY - OTHER	132557	Prepaid-FSA O&M - Glenrock I	SG	185	3	50	14	26	83	10	0	-
1652100	PREPAY - OTHER	132558	Prepaid-FSA O&M - Glenrock III	SG	146	2	39	11	20	66	8	0	-
1652100	PREPAY - OTHER	132561	Prepaid-FSA O&M - Goodnoe Hills	SG	231	3	62	17	32	104	13	0	-
1652100	PREPAY - OTHER	132564	Prepaid-FSA O&M - High Plains	SG	556	8	150	42	77	250	31	0	-
1652100	PREPAY - OTHER	132567	Prepaid-FSA O&M - Leaning Juniper	SG	282	4	76	21	39	127	16	0	-
1652100	PREPAY - OTHER	132570	Prepaid-FSA O&M - Marengo I	SG	358	5	96	27	49	161	20	0	-
1652100	PREPAY - OTHER	132571	Prepaid-FSA O&M - Marengo II	SG	179	2	48	13	25	80	10	0	-
1652100	PREPAY - OTHER	132574	Prepaid-FSA O&M - McFadden Ridge	SG	107	1	29	8	15	48	6	0	-
1652100	PREPAY - OTHER	132576	Prepaid-FSA O&M - Pryor Mtn	SG	541	7	146	41	75	243	30	0	-
1652100	PREPAY - OTHER	132577	Prepaid-FSA O&M - Rolling Hills	SG	278	4	75	21	38	125	16	0	-
1652100	PREPAY - OTHER	132580	Prepaid-FSA O&M - Seven Mile I	SG	185	3	50	14	26	83	10	0	-
1652100	PREPAY - OTHER	132581	Prepaid-FSA O&M - Seven Mile II	SG	37	1	10	3	5	16	2	0	-
1652100	PREPAY - OTHER	132584	Prepaid-FSA O&M - TB Flats I	SG	330	5	89	25	46	148	18	0	-
1652100	PREPAY - OTHER	132585	Prepaid-FSA O&M - TB Flats II	SG	344	5	92	26	47	154	19	0	-
1652100	PREPAY - OTHER	132608	Prepaid - Records Management Costs	SG	66	1	18	5	9	30	4	0	-
1652100	PREPAY - OTHER	132620	PREPAYMENTS - WATER RIGHTS LEASE	SG	578	8	155	43	80	259	32	0	-
1652100	PREPAY - OTHER	132621	Prepayments - Water Rights (Ferron Canal	SG	223	3	60	17	31	100	12	0	-
1652100	PREPAY - OTHER	132622	Prepayments - Water Rights (Hntgtn-Clev)	SG	264	4	71	20	36	119	15	0	-
1652100	PREPAY - OTHER	132650	PREPAID DUES	SO	3,455	91	948	253	439	1,536	188	0	-
1652100	PREPAY - OTHER	132700	PREPAID RENT	GPS	11	0	3	1	1	5	1	0	-
1652100	PREPAY - OTHER	132740	PREPAID O&M WIND	SG	85	1	23	6	12	38	5	0	-
1652100	PREPAY - OTHER	132755	Prepaid Aircraft Maintenance Costs	SG	110	2	29	8	15	49	6	0	-
1652100	PREPAY - OTHER	132900	PREPAYMENTS - OTHER	SE	72	1	19	5	11	32	4	0	-
1652100	PREPAY - OTHER	132900	PREPAYMENTS - OTHER	SO	1,468	39	403	107	187	653	80	0	-
1652100	PREPAY - OTHER	132901	PRE FEES - OREGON PUB UTIL COMMISSION	OR	4,550	-	4,550	-	-	-	-	-	-
1652100	PREPAY - OTHER	132903	PREP FEES-UTAH PUBLIC SERVICE COMMISSION	UT	6,908	-	-	-	-	6,908	-	-	-
1652100	PREPAY - OTHER	132904	PREP FEES-IDAHO PUB UTIL COMMISSION	IDU	312	-	-	-	-	-	312	-	-

PACIFICORP

Miscellaneous Rate Base (Actuals)
Year End: 06/2023
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1652100	PREPAY - OTHER	132910	Prepayments - Hardware & Software	SO	27,040	709	7,416	1,978	3,439	12,023	1,474	0	-
1652100	PREPAY - OTHER	132999	PREPAY - RECLASS TO LT	SO	(3,253)	(85)	(892)	(238)	(414)	(1,446)	(177)	(0)	-
1652100	PREPAY - OTHER	134000	L/T PREPAY RECLASS	SO	3,253	85	892	238	414	1,446	177	0	-
1652100	PREPAY - OTHER	134100	Prepaid CA GHG Retail - Non-Current	OTHE	22,954	-	-	-	-	-	-	-	22,954
1652100	PREPAY - OTHER	134101	Prepaid CA GHG Wholesale - Non-Current	OTHE	10,174	-	-	-	-	-	-	-	10,174
1652100 Total					**89,448**	**925**	**15,000**	**2,807**	**4,928**	**23,932**	**2,406**	**0**	**39,450**
1655000	PREPAY-COAL MIN EX	132400	PREPAID - TAXES	SE	516	7	136	35	77	230	31	0	-
1655000 Total					**516**	**7**	**136**	**35**	**77**	**230**	**31**	**0**	**-**
2281000	ACC PROV-PROP INS	288711	Reg Liab - CA Property Insurance Reserve	CA	3,367	3,367	-	-	-	-	-	-	-
2281000	ACC PROV-PROP INS	288712	Reg Liab - OR Property Insurance Reserve	OR	31,639	-	31,639	-	-	-	-	-	-
2281000	ACC PROV-PROP INS	288713	Reg Liab - WA Property Insurance Reserve	WA	318	-	-	318	-	-	-	-	-
2281000	ACC PROV-PROP INS	288714	Reg Liab - ID Property Insurance Reserve	IDU	(1,117)	-	-	-	-	-	(1,117)	-	-
2281000	ACC PROV-PROP INS	288715	Reg Liab - UT Property Insurance Reserve	UT	707	-	-	-	-	707	-	-	-
2281000	ACC PROV-PROP INS	288716	Reg Liab - WY Property Insurance Reserve	WYP	(558)	-	-	-	(558)	-	-	-	-
2281000	ACC PROV-PROP INS	288747	RegL-CA Insurance Reserves-Recl to Asst	OTHE	(3,367)	-	-	-	-	-	-	-	(3,367)
2281000	ACC PROV-PROP INS	288748	RegL-WA Insurance Reserves-Recl to Asst	OTHE	(318)	-	-	-	-	-	-	-	(318)
2281000	ACC PROV-PROP INS	288749	RegL - Insurance Reserves - Reclass	OTHE	(31,639)	-	-	-	-	-	-	-	(31,639)
2281000 Total					**(968)**	**3,367**	**31,639**	**318**	**(558)**	**707**	**(1,117)**	**-**	**(35,324)**
2281200	ACC PRV-INS-T&D LN	280307	Accum Prov For Prop Ins - Pac Power T&D	SO	(10,000)	(262)	(2,743)	(732)	(1,272)	(4,446)	(545)	(0)	-
2281200 Total					**(10,000)**	**(262)**	**(2,743)**	**(732)**	**(1,272)**	**(4,446)**	**(545)**	**(0)**	**-**
2282100	ACC PRV IN & DAMAG	280310	Prov for Injuries & Damages - General	SO	(4,717)	(124)	(1,294)	(345)	(600)	(2,097)	(257)	(0)	-
2282100	ACC PRV IN & DAMAG	280311	ACC. PROV. I & D - EXCL. AUTO	SO	(948,049)	(24,871)	(260,007)	(69,363)	(120,568)	(421,548)	(51,692)	(0)	-
2282100	ACC PRV IN & DAMAG	280314	I & D Provisions - Reclass to Current	SO	62,417	1,637	17,118	4,567	7,938	27,754	3,403	0	-
2282100 Total					**(890,349)**	**(23,357)**	**(244,182)**	**(65,141)**	**(113,230)**	**(395,892)**	**(48,545)**	**(0)**	**-**
2282400	ACCUM PRV FR I&D-OR	288700	Reg Liab - OR Injuries & Damages Reserve	OR	5,480	-	5,480	-	-	-	-	-	-
2282400	ACCUM PRV FR I&D-OR	288701	Contra Reg Liab - OR Injuries & Damages	OR	(9,797)	-	(9,797)	-	-	-	-	-	-
2282400 Total					**(4,317)**	**-**	**(4,317)**	**-**	**-**	**-**	**-**	**-**	**-**
2282500	Acc Prov I&D-Insur	156909	Insurance Reim Receivable (I&D)-NonCurr	SO	378,850	9,939	103,901	27,718	48,180	168,455	20,656	0	-
2282500	Acc Prov I&D-Insur	156911	Insurance Reim Rec-Reclass to Current	SO	(14,700)	(386)	(4,032)	(1,076)	(1,869)	(6,536)	(802)	(0)	-
2282500 Total					**364,150**	**9,553**	**99,870**	**26,643**	**46,311**	**161,919**	**19,855**	**0**	**-**
2283000	PEN/BENFT-SICK	280349	SUPPL. PENSION BENEFITS (RETIRE ALLOW)	SO	(1,253)	(33)	(344)	(92)	(159)	(557)	(68)	(0)	-
2283000 Total					**(1,253)**	**(33)**	**(344)**	**(92)**	**(159)**	**(557)**	**(68)**	**(0)**	**-**
2283400	POST-RETIREMENT BEN	280329	FAS 106-Contra Liability-Medicare Subsid	SO	22,389	587	6,140	1,638	2,847	9,955	1,221	0	-
2283400	POST-RETIREMENT BEN	280440	FAS 158 PR Liab Medicare Sub (Non-Dedct)	SO	(5,429)	(142)	(1,489)	(397)	(690)	(2,414)	(296)	(0)	-
2283400	POST-RETIREMENT BEN	280454	FAS 158 PR Liab Reg Medicare (Non-Dedct)	SO	5,429	142	1,489	397	690	2,414	296	0	-
2283400	POST-RETIREMENT BEN	280456	FAS 106-Contra Liab-Med.Sub.Claims	SO	(16,960)	(445)	(4,651)	(1,241)	(2,157)	(7,541)	(925)	(0)	-
2283400	POST-RETIREMENT BEN	280457	FAS 158 - CONTRA LIA - Reg Medicare	SO	(5,429)	(142)	(1,489)	(397)	(690)	(2,414)	(296)	(0)	-
2283400 Total					**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
2283500	PENSIONS	280350	Pension - Local 57	SO	(454)	(12)	(125)	(33)	(58)	(202)	(25)	(0)	-
2283500	PENSIONS	280365	FAS 158 Pension Liab-Rcls to Current	SO	454	12	125	33	58	202	25	0	-
2283500 Total					**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
2284100	AC MIS OP PR-OTHER	289320	CHEHALIS WA EFSEC C02 MITIGATION OBLIG	SG	(235)	(3)	(63)	(18)	(32)	(105)	(13)	(0)	-
2284100 Total					**(235)**	**(3)**	**(63)**	**(18)**	**(32)**	**(105)**	**(13)**	**(0)**	**-**
2300000	ASSET RETIREMENT OBL	284918	ARO LIAB - TROJAN NUCLEAR PLANT	TROJ	(6,946)	(94)	(1,861)	(512)	(970)	(3,115)	(394)	(0)	-
2300000 Total					**(6,946)**	**(94)**	**(1,861)**	**(512)**	**(970)**	**(3,115)**	**(394)**	**(0)**	**-**
2530000	OTHER DEF CREDITS	289005	UNEARNED JOINT USE POLE CONTACT REVENUE	CA	(63)	(63)	-	-	-	-	-	-	-
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	(331)	-	(331)	-	-	-	-	-	-
2530000	OTHER DEF CREDITS	289005	UNEARNED JOINT USE POLE CONTACT REVENUE	UT	(74)	-	-	-	-	(74)	-	-	-
2530000	OTHER DEF CREDITS	289005	UNEARNED JOINT USE POLE CONTACT REVENUE	WA	(15)	-	-	(15)	-	-	-	-	-
2530000	OTHER DEF CREDITS	289005	UNEARNED JOINT USE POLE CONTACT REVENUE	WYP	(33)	-	-	-	(33)	-	-	-	-

PACIFICORP

Miscellaneous Rate Base (Actuals)
Year End: 06/2023
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
2530000 Total					**(530)**	**(63)**	**(331)**	**(15)**	**(33)**	**(74)**	**(15)**	**-**	**-**
2533500	OTH DEF CR-PEN & BEN	280370	PENSION LIAB-UMWA WITHDRAWAL OBLIG	SE	(115,119)	(1,463)	(30,321)	(7,851)	(17,105)	(51,455)	(6,924)	(0)	-
2533500 Total					**(115,119)**	**(1,463)**	**(30,321)**	**(7,851)**	**(17,105)**	**(51,455)**	**(6,924)**	**(0)**	**-**
2539900	OTH DEF CR - OTHER	0	Fossil Rock Fuels Entries	SE	(5,006)	(64)	(1,319)	(341)	(744)	(2,238)	(301)	(0)	-
2539900	OTH DEF CR - OTHER	230155	EMPLOYEE HOUSING SECURITY DEPOSITS	CA	(21)	(21)	-	-	-	-	-	-	-
2539900	OTH DEF CR - OTHER	284902	IT Software Licenses	SO	(12,178)	(319)	(3,340)	(891)	(1,549)	(5,415)	(664)	(0)	-
2539900	OTH DEF CR - OTHER	289051	DEFERRED RENT REVENUE AMORT OIL & GAS LE	SG	(1,887)	(26)	(507)	(141)	(260)	(847)	(106)	(0)	-
2539900	OTH DEF CR - OTHER	289341	Accrued Royalties-Reg Rcvry-Noncurrent	SE	(15,783)	(201)	(4,157)	(1,076)	(2,345)	(7,055)	(949)	(0)	-
2539900	OTH DEF CR - OTHER	289523	Govt Coal Lease Bonus Payment Liability	SE	5,006	64	1,319	341	744	2,238	301	0	-
2539900	OTH DEF CR - OTHER	289913	MCI - F.O.G. WIRE LEASE	SG	(514)	(7)	(138)	(38)	(71)	(231)	(29)	(0)	-
2539900	OTH DEF CR - OTHER	289914	TRANSMISSION SERVICE DEPOSITS - THIRD PA	SG	(5,857)	(81)	(1,575)	(439)	(807)	(2,629)	(328)	(0)	-
2539900	OTH DEF CR - OTHER	289923	Transmission Cluster Study Deposits	SG	(56,425)	(777)	(15,169)	(4,225)	(7,773)	(25,324)	(3,157)	(0)	-
2539900	OTH DEF CR - OTHER	289925	TRANSM CONST SECURITY DEPOSITS	SG	(63,243)	(871)	(17,002)	(4,736)	(8,713)	(28,384)	(3,538)	(0)	-
2539900	OTH DEF CR - OTHER	289927	Transm Deposit - Readiness Fin Security	SG	(172,545)	(2,376)	(46,387)	(12,921)	(23,770)	(77,439)	(9,653)	(0)	-
2539900	OTH DEF CR - OTHER	289928	Transmission Deposits-Site Control	SG	(2,220)	(31)	(597)	(166)	(306)	(996)	(124)	(0)	-
2539900	OTH DEF CR - OTHER	289955	Accrued Right-of-Way Obligations	SG	(2,028)	(28)	(545)	(152)	(279)	(910)	(113)	(0)	-
2539900	OTH DEF CR - OTHER	289993	LT Acc- Misc Exp - Reclass from Current	OTHE	(2,549)	-	-	-	-	-	-	-	(2,549)
2539900	OTH DEF CR - OTHER	289994	Long-Term Trade AP - Recl from Current	OTHE	(72,456)	-	-	-	-	-	-	-	(72,456)
2539900 Total					**(407,708)**	**(4,736)**	**(89,419)**	**(24,786)**	**(45,873)**	**(149,229)**	**(18,660)**	**(0)**	**(75,006)**
2540000	REGULATORY LIAB	187394	RegA - UT Solar Feed-In - Recl to Liab	OTHE	463	-	-	-	-	-	-	-	463
2540000	REGULATORY LIAB	231010	Reg Liab Current - Blue Sky	OTHE	(7,196)	-	-	-	-	-	-	-	(7,196)
2540000	REGULATORY LIAB	231020	Reg Liab Current - DSM	OTHE	(4,748)	-	-	-	-	-	-	-	(4,748)
2540000	REGULATORY LIAB	231045	Reg Liab Current - GHG Allowances	OTHE	(6,054)	-	-	-	-	-	-	-	(6,054)
2540000	REGULATORY LIAB	231050	Reg Liab Current - Def Net Power Costs	OTHE	(4,027)	-	-	-	-	-	-	-	(4,027)
2540000	REGULATORY LIAB	231080	Reg Liab Current - REC Sales	OTHE	(3,750)	-	-	-	-	-	-	-	(3,750)
2540000	REGULATORY LIAB	231090	Reg Liab Current - Solar Feed-In	OTHE	(7,389)	-	-	-	-	-	-	-	(7,389)
2540000	REGULATORY LIAB	231095	Reg Liab Current - Income Tax Related	OTHE	(44,242)	-	-	-	-	-	-	-	(44,242)
2540000	REGULATORY LIAB	231100	Reg Liab Current - Other	OTHE	(21,168)	-	-	-	-	-	-	-	(21,168)
2540000	REGULATORY LIAB	288001	Reg Liab - Excess Def Inc Taxes - CA	CA	(26)	(26)	-	-	-	-	-	-	-
2540000	REGULATORY LIAB	288005	Reg Liab - Excess Def Inc Taxes - WA	WA	(723)	-	-	(723)	-	-	-	-	-
2540000	REGULATORY LIAB	288021	Reg Liab-FAS 158 Post-Retirement	SO	(33,831)	(888)	(9,278)	(2,475)	(4,303)	(15,043)	(1,845)	(0)	-
2540000	REGULATORY LIAB	288061	Reg L-WA Decoupling Mech Jul20-Jun21	OTHE	2,293	-	-	-	-	-	-	-	2,293
2540000	REGULATORY LIAB	288062	Reg L-WA Decoupling Mech Jan22-Dec22	OTHE	(3,808)	-	-	-	-	-	-	-	(3,808)
2540000	REGULATORY LIAB	288063	Reg L-WA Decoupling Mech Jan23-Dec23	OTHE	(5,431)	-	-	-	-	-	-	-	(5,431)
2540000	REGULATORY LIAB	288072	Contra Reg A-WA Decoupling Jan22-Dec22	OTHE	273	-	-	-	-	-	-	-	273
2540000	REGULATORY LIAB	288073	Contra Reg A-WA Decoupling Jan23-Dec23	OTHE	(572)	-	-	-	-	-	-	-	(572)
2540000	REGULATORY LIAB	288079	RegL-WA Decoupling Mech - Recl to Curr	OTHE	653	-	-	-	-	-	-	-	653
2540000	REGULATORY LIAB	288081	Reg Liab - Cholla Decomm - CA	CA	99	99	-	-	-	-	-	-	-
2540000	REGULATORY LIAB	288082	Reg Liab - Cholla Decomm - ID	IDU	(2,335)	-	-	-	-	-	(2,335)	-	-
2540000	REGULATORY LIAB	288083	Reg Liab - Cholla Decomm - OR	OR	(7,552)	-	(7,552)	-	-	-	-	-	-
2540000	REGULATORY LIAB	288084	Reg Liab - Cholla Decomm - UT	UT	(17,685)	-	-	-	-	(17,685)	-	-	-
2540000	REGULATORY LIAB	288086	Reg Liab - Cholla Decomm - WY	WYP	(318)	-	-	-	(318)	-	-	-	-
2540000	REGULATORY LIAB	288099	RegL-Depr/Amortz Deferral-Bal Reclass	OTHE	(99)	-	-	-	-	-	-	-	(99)
2540000	REGULATORY LIAB	288114	REG LIABILITY - OR GAIN-SALE EPUD ASSETS	OTHE	1	-	-	-	-	-	-	-	1
2540000	REGULATORY LIAB	288159	RegL - Blue Sky - Recl to Curr	OTHE	7,196	-	-	-	-	-	-	-	7,196
2540000	REGULATORY LIAB	288161	RL-Energy Savings Assistance (ESA)-CA	OTHE	(143)	-	-	-	-	-	-	-	(143)
2540000	REGULATORY LIAB	288162	Reg Liab-CA Klamath River Dams Removal	CA	(262)	(262)	-	-	-	-	-	-	-
2540000	REGULATORY LIAB	288165	Reg Liab - OR Enrgy	OTHE	(5,663)	-	-	-	-	-	-	-	(5,663)
2540000	REGULATORY LIAB	288174	RegL - OR Asset Sale Gain-Balance Recl	OTHE	(3,203)	-	-	-	-	-	-	-	(3,203)
2540000	REGULATORY LIAB	288184	Reg Liability - Sale of RECs - WA	OTHE	(0)	-	-	-	-	-	-	-	(0)
2540000	REGULATORY LIAB	288191	RegL - OR Pryor Mtn REC	OTHE	(348)	-	-	-	-	-	-	-	(348)
2540000	REGULATORY LIAB	288211	Reg Liab - Non-Prot PP&E EDIT - CA	CA	(100)	(100)	-	-	-	-	-	-	-

PACIFICORP

Miscellaneous Rate Base (Actuals)
Year End: 06/2023
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	288214	Reg Liab - Non-Prot PP&E EDIT - WA	WA	(14,284)	-	-	(14,284)	-	-	-	-	-
2540000	REGULATORY LIAB	288215	Reg Liab - Non-Prot PP&E EDIT - WY	WYP	(18,218)	-	-	-	(18,218)	-	-	-	-
2540000	REGULATORY LIAB	288232	Reg Liab - OR 2017 FERC Rate True-Up	OTHE	(2,024)	-	-	-	-	-	-	-	(2,024)
2540000	REGULATORY LIAB	288260	Reg Liability - WA PCAM CY2021	OTHE	27,898	-	-	-	-	-	-	-	27,898
2540000	REGULATORY LIAB	288262	Reg Liability - WA PCAM CY2022	OTHE	63,599	-	-	-	-	-	-	-	63,599
2540000	REGULATORY LIAB	288263	Contra Reg Liability - WA PCAM CY2022	OTHE	(3,056)	-	-	-	-	-	-	-	(3,056)
2540000	REGULATORY LIAB	288264	Reg Liability - WA PCAM PTC CY2021	OTHE	1,925	-	-	-	-	-	-	-	1,925
2540000	REGULATORY LIAB	288285	Reg Liab-Excess Income Tax Deferral-WA	OTHE	(6,669)	-	-	-	-	-	-	-	(6,669)
2540000	REGULATORY LIAB	288286	Reg Liab-Excess Income Tax Deferral-WY	OTHE	(1,340)	-	-	-	-	-	-	-	(1,340)
2540000	REGULATORY LIAB	288404	Reg Liab - OR Fly Ash	OTHE	(1,402)	-	-	-	-	-	-	-	(1,402)
2540000	REGULATORY LIAB	288405	Reg Liab-OR Direct Access 5 yr Opt Out	OTHE	(4,399)	-	-	-	-	-	-	-	(4,399)
2540000	REGULATORY LIAB	288406	Reg L-OR-Bridger Mine Accel Depr&Reclm	OR	(9,096)	-	(9,096)	-	-	-	-	-	-
2540000	REGULATORY LIAB	288409	Reg Liab-WA-Plant Closure Cost Deferral	WA	(3,389)	-	-	(3,389)	-	-	-	-	-
2540000	REGULATORY LIAB	288410	Reg Liab-WA-Bridger Mine Accel Depr	WA	(6,374)	-	-	(6,374)	-	-	-	-	-
2540000	REGULATORY LIAB	288411	Reg Liab - WA-Accel Depr 2015 GRC	WA	(8,709)	-	-	(8,709)	-	-	-	-	-
2540000	REGULATORY LIAB	288412	Reg Liab - Depr Decrease Deferral - OR	OTHE	(1,415)	-	-	-	-	-	-	-	(1,415)
2540000	REGULATORY LIAB	288420	Reg Liab - CA GHG Allowance Revenues	OTHE	(5,094)	-	-	-	-	-	-	-	(5,094)
2540000	REGULATORY LIAB	288422	Reg Liab - CA Solar (SOMAH)-GHG Funds	OTHE	(8,833)	-	-	-	-	-	-	-	(8,833)
2540000	REGULATORY LIAB	288423	RegL - CA GHG Allowances - Recl to Curr	OTHE	6,054	-	-	-	-	-	-	-	6,054
2540000	REGULATORY LIAB	288443	RegL - OR RECs in Rates - Recl to Curr	OTHE	3,365	-	-	-	-	-	-	-	3,365
2540000	REGULATORY LIAB	288444	RegL - UT RECs in Rates - Recl to Curr	OTHE	134	-	-	-	-	-	-	-	134
2540000	REGULATORY LIAB	288445	RegL - WA RECs in Rates - Recl to Curr	OTHE	0	-	-	-	-	-	-	-	0
2540000	REGULATORY LIAB	288446	RegL - WY RECs in Rates - Recl to Curr	OTHE	251	-	-	-	-	-	-	-	251
2540000	REGULATORY LIAB	288451	RegL - WA Pryor Mtn REC	OTHE	(153)	-	-	-	-	-	-	-	(153)
2540000	REGULATORY LIAB	288454	RegL - UT RECs in Rates - Balance Recl	OTHE	(3,451)	-	-	-	-	-	-	-	(3,451)
2540000	REGULATORY LIAB	288456	RegL - WY RECs in Rates - Balance Recl	OTHE	(1,260)	-	-	-	-	-	-	-	(1,260)
2540000	REGULATORY LIAB	288459	Reg Liab - Def RECs in Rates - Reclass	OTHE	(186)	-	-	-	-	-	-	-	(186)
2540000	REGULATORY LIAB	288461	RegL - CA Def Exc NPC - Recl to Curr	OTHE	4,027	-	-	-	-	-	-	-	4,027
2540000	REGULATORY LIAB	288471	RegL - CA Def Exc NPC - Balance Reclass	OTHE	(4,027)	-	-	-	-	-	-	-	(4,027)
2540000	REGULATORY LIAB	288475	RegL - WA Def Exc NPC - Balance Reclass	OTHE	(90,367)	-	-	-	-	-	-	-	(90,367)
2540000	REGULATORY LIAB	288484	RegL - UT Solar Feed-In - Recl to Curr	OTHE	7,389	-	-	-	-	-	-	-	7,389
2540000	REGULATORY LIAB	288494	RegL - UT Solar Feed-In - Balance Recl	OTHE	(7,389)	-	-	-	-	-	-	-	(7,389)
2540000	REGULATORY LIAB	288817	RegL - DSM - CA - Reclass to Current	OTHE	142	-	-	-	-	-	-	-	142
2540000	REGULATORY LIAB	288819	Reg Liab - DSM - CA - Balance Reclass	OTHE	(142)	-	-	-	-	-	-	-	(142)
2540000	REGULATORY LIAB	288827	RegL - DSM - ID - Reclass to Current	OTHE	1,457	-	-	-	-	-	-	-	1,457
2540000	REGULATORY LIAB	288829	Reg Liab - DSM - ID - Balance Reclass	OTHE	(1,457)	-	-	-	-	-	-	-	(1,457)
2540000	REGULATORY LIAB	288857	RegL - DSM - WA - Reclass to Current	OTHE	3,150	-	-	-	-	-	-	-	3,150
2540000	REGULATORY LIAB	288859	Reg Liab - DSM - WA - Balance Reclass	OTHE	(3,150)	-	-	-	-	-	-	-	(3,150)
2540000	REGULATORY LIAB	288931	Reg Liab - Protected PP&E EDIT - CA	CA	(30,764)	(30,764)	-	-	-	-	-	-	-
2540000	REGULATORY LIAB	288932	Reg Liab - Protected PP&E EDIT - ID	IDU	(78,625)	-	-	-	-	-	(78,625)	-	-
2540000	REGULATORY LIAB	288933	Reg Liab - Protected PP&E EDIT - OR	OR	(342,778)	-	(342,778)	-	-	-	-	-	-
2540000	REGULATORY LIAB	288934	Reg Liab - Protected PP&E EDIT - WA	WA	(74,590)	-	-	(74,590)	-	-	-	-	-
2540000	REGULATORY LIAB	288935	Reg Liab - Protected PP&E EDIT - WY	WYP	(194,510)	-	-	-	(194,510)	-	-	-	-
2540000	REGULATORY LIAB	288936	Reg Liab - Protected PP&E EDIT - UT	UT	(609,056)	-	-	-	-	(609,056)	-	-	-
2540000	REGULATORY LIAB	288941	Reg Liab - Protected PP&E ARAM - CA	CA	(788)	(788)	-	-	-	-	-	-	-
2540000	REGULATORY LIAB	288942	Reg Liab - Protected PP&E ARAM - ID	IDU	(3,071)	-	-	-	-	-	(3,071)	-	-
2540000	REGULATORY LIAB	288943	Reg Liab - Protected PP&E ARAM - OR	OR	(2)	-	(2)	-	-	-	-	-	-
2540000	REGULATORY LIAB	288945	Reg Liab - Protected PP&E ARAM - WA	WA	(8,701)	-	-	(8,701)	-	-	-	-	-
2540000	REGULATORY LIAB	288946	Reg Liab - Protected PP&E ARAM - WY	WYU	(16,877)	-	-	-	(16,877)	-	-	-	-
2540000	REGULATORY LIAB	288948	RegL-Income Tax Related-Recl to Asset	OTHE	(527)	-	-	-	-	-	-	-	(527)
2540000	REGULATORY LIAB	288949	RegL - EDIT Deferral - Recl to Curr	OTHE	44,242	-	-	-	-	-	-	-	44,242
2540000	REGULATORY LIAB	288995	RegL - Other - Recl to Curr	OTHE	20,515	-	-	-	-	-	-	-	20,515

Miscellaneous Rate Base (Actuals)
Year End: 06/2023
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account	Secondary Account	Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
2540000 Total			(1,551,720)	(32,728)	(368,706)	(119,245)	(234,225)	(641,784)	(85,875)	(0)	(69,156)
Grand Total			(2,411,917)	(45,935)	(564,432)	(180,253)	(347,634)	(999,972)	(133,655)	(0)	(140,036)

B16. REGULATORY ASSETS

PACIFICORP

Regulatory Assets (Actuals)
Year End: 06/2023
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	692	-	-	-	-	-	-	-	692
1242000	PAC PWR-INT FREE LN	0	INT FREE-PPL	WA	7	-	-	7	-	-	-	-	-
1242000 Total					**699**	**-**	**-**	**7**	**-**	**-**	**-**	**-**	**692**
1247100	CSS/ELI SYSTEM LOANS	0	CSS/ELI SYSTEM	OTHER	5	-	-	-	-	-	-	-	5
1247100 Total					**5**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**5**
1249000	RESV UNCOLL ESC&WZ	0	ESC - RESERVE	OTHER	(183)	-	-	-	-	-	-	-	(183)
1249000	RESV UNCOLL ESC&WZ	0	ESC - RESERVE	UT	0	-	-	-	-	0	-	-	-
1249000	RESV UNCOLL ESC&WZ	0	ESC - RESERVE	WA	(4)	-	-	(4)	-	-	-	-	-
1249000 Total					**(187)**	**-**	**-**	**(4)**	**-**	**0**	**-**	**-**	**(183)**
1823000	DSR REGULATORY ASSET	0	DSR REGULATORY ASSETS	OTHER	(125,470)	-	-	-	-	-	-	-	(125,470)
1823000 Total					**(125,470)**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**(125,470)**
1823700	OTH REGA-ENERGY WEST	186817	Contra RA-DCM PP&E-Amortz & Oth Adjs	CA	166	166	-	-	-	-	-	-	-
1823700	OTH REGA-ENERGY WEST	186817	Contra RA-DCM PP&E-Amortz & Oth Adjs	OR	752	-	752	-	-	-	-	-	-
1823700	OTH REGA-ENERGY WEST	186817	Contra RA-DCM PP&E-Amortz & Oth Adjs	SE	(1,662)	(21)	(438)	(113)	(247)	(743)	(100)	(0)	-
1823700	OTH REGA-ENERGY WEST	186817	Contra RA-DCM PP&E-Amortz & Oth Adjs	WA	744	-	-	744	-	-	-	-	-
1823700	OTH REGA-ENERGY WEST	186820	Reg Asset-Deer Creek Mine ARO	SE	6,524	83	1,718	445	969	2,916	392	0	-
1823700	OTH REGA-ENERGY WEST	186825	Reg Asset-Deer Creek Mine M&S	SE	4,492	57	1,183	306	667	2,008	270	0	-
1823700	OTH REGA-ENERGY WEST	186826	Reg Asset-Deer Creek-Prepaid Royalties	SE	843	11	222	57	125	377	51	0	-
1823700	OTH REGA-ENERGY WEST	186828	Reg Asset-Deer Creek-Recovery Royalties	SE	15,783	201	4,157	1,076	2,345	7,055	949	0	-
1823700	OTH REGA-ENERGY WEST	186829	Contra RA-DCM Closure-Royalties Amortz	IDU	(520)	-	-	-	-	-	(520)	-	-
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	20	425	110	239	720	97	0	-
1823700	OTH REGA-ENERGY WEST	186833	Reg Asset-Deer Creek-Nonunion Severance	SE	2,770	35	730	189	412	1,238	167	0	-
1823700	OTH REGA-ENERGY WEST	186835	Reg Asset-Deer Creek-Misc Closure Costs	SE	45,112	573	11,882	3,077	6,703	20,164	2,713	0	-
1823700	OTH REGA-ENERGY WEST	186836	Contra RA-DCM Closure-To Joint Owners	SE	(3,184)	(40)	(839)	(217)	(473)	(1,423)	(192)	(0)	-
1823700	OTH REGA-ENERGY WEST	186837	Contra RA-DCM Closure-Amortz & Oth Adjs	IDU	(1,896)	-	-	-	-	-	(1,896)	-	-
1823700	OTH REGA-ENERGY WEST	186837	Contra RA-DCM Closure-Amortz & Oth Adjs	OTHER	(11,831)	-	-	-	-	-	-	-	(11,831)
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	38	785	203	443	1,331	179	0	-
1823700	OTH REGA-ENERGY WEST	186851	Contra Reg Asset-Deer Creek Closure-CA	CA	(1,278)	(1,278)	-	-	-	-	-	-	-
1823700	OTH REGA-ENERGY WEST	186852	CONTRA REG ASSET-DEER CREEK CLOSURE-ID	IDU	(1,336)	-	-	-	-	-	(1,336)	-	-
1823700	OTH REGA-ENERGY WEST	186853	Contra Reg Asset-Deer Creek Closure-OR	OR	(1,946)	-	(1,946)	-	-	-	-	-	-
1823700	OTH REGA-ENERGY WEST	186855	Contra Reg Asset-Deer Creek Closure-WA	WA	(4,281)	-	-	(4,281)	-	-	-	-	-
1823700	OTH REGA-ENERGY WEST	186861	RA-Deer Creek-ROR Offset-Fuel Inventory	IDU	(1,669)	-	-	-	-	-	(1,669)	-	-
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	186863	RA-Deer Creek-ROR Offset-Note Intrst-ID	IDU	(191)	-	-	-	-	-	(191)	-	-
1823700	OTH REGA-ENERGY WEST	186871	RA-DC ROR Offset-Fuel Inventory-Amortz	IDU	835	-	-	-	-	-	835	-	-
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	186873	RA-DC ROR Offset-Note Interest-Amortz	IDU	95	-	-	-	-	-	95	-	-
1823700	OTH REGA-ENERGY WEST	186881	Reg Asset-UMWA Pension Trust Oblig	SE	115,119	1,463	30,321	7,851	17,105	51,455	6,924	0	-
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					**115,348**	**1,308**	**48,953**	**9,447**	**14,688**	**58,864**	**6,769**	**0**	**(24,681)**
1823750	OTHER REG A-CHLA U4	185831	Reg Asset - Cholla Unrec Plant - CA	CA	3,926	3,926	-	-	-	-	-	-	-
1823750	OTHER REG A-CHLA U4	185836	Reg Asset - Cholla Unrec Plant - WY	WYP	34,289	-	-	-	34,289	-	-	-	-
1823750	OTHER REG A-CHLA U4	185864	Reg Asset-Cholla U4-Property Taxes-OR	OTHER	611	-	-	-	-	-	-	-	611
1823750	OTHER REG A-CHLA U4	185866	Reg Asset-Cholla U4-Nonunion Severance	SG	2,424	33	652	181	334	1,088	136	0	-

PACIFICORP

Regulatory Assets (Actuals)
Year End: 06/2023
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1823750	OTHER REG A-CHLA U4	185867	Reg Asset-Cholla U4-Safe Harbor Lease	SG	102	1	27	8	14	46	6	0	-
1823750	OTHER REG A-CHLA U4	185874	Contra Reg Asset-Cholla U4 Closure-UT	UT	(1,238)	-	-	-	-	(1,238)	-	-	-
1823750	OTHER REG A-CHLA U4	185876	Contra Reg Asset-Cholla U4 Closure-WY	WYP	(411)	-	-	-	(411)	-	-	-	-
1823750 Total					**39,702**	**3,961**	**679**	**189**	**34,225**	**(104)**	**141**	**0**	**611**
1823870	DEFERRED PENSION	187017	FAS 158 Pen Liab Adj	SO	258,517	6,782	70,899	18,914	32,877	114,949	14,095	0	-
1823870	DEFERRED PENSION	187608	Reg Asset - Pension Settlement - CA	OTHER	1,299	-	-	-	-	-	-	-	1,299
1823870	DEFERRED PENSION	187611	Reg Asset - Pension Settlement - OR	OTHER	10,753	-	-	-	-	-	-	-	10,753
1823870	DEFERRED PENSION	187612	Reg Asset - Pension Settlement - UT	OTHER	4,606	-	-	-	-	-	-	-	4,606
1823870	DEFERRED PENSION	187613	Reg Asset - Pension Settlement - WY	WYU	4,965	-	-	-	4,965	-	-	-	-
1823870	DEFERRED PENSION	187621	Reg Asset FAS - 158	SO	(34,098)	(895)	(9,352)	(2,495)	(4,336)	(15,162)	(1,859)	(0)	-
1823870	DEFERRED PENSION	187629	Reg Asset - Post-Ret - Settlement Loss	CA	(127)	(127)	-	-	-	-	-	-	-
1823870	DEFERRED PENSION	187629	Reg Asset - Post-Ret - Settlement Loss	IDU	(260)	-	-	-	-	-	(260)	-	-
1823870	DEFERRED PENSION	187629	Reg Asset - Post-Ret - Settlement Loss	OTHER	(1,637)	-	-	-	-	-	-	-	(1,637)
1823870	DEFERRED PENSION	187629	Reg Asset - Post-Ret - Settlement Loss	SO	8,323	218	2,283	609	1,058	3,701	454	0	-
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	33,831	888	9,278	2,475	4,303	15,043	1,845	0	-
1823870 Total					**280,533**	**6,866**	**73,109**	**18,843**	**37,455**	**114,965**	**14,274**	**0**	**15,021**
1823910	ENVIR CST UNDR AMORT	102465	UTAH METALS CLEANUP	SO	148	4	41	11	19	66	8	0	-
1823910	ENVIR CST UNDR AMORT	103408	D-SM RETAIL MINOR SITES	SO	3,832	101	1,051	280	487	1,704	209	0	-
1823910	ENVIR CST UNDR AMORT	103420	ASTORIA YOUNGS BAY CLEANUP	SO	477	13	131	35	61	212	26	0	-
1823910	ENVIR CST UNDR AMORT	103426	SILVER BELL MINE ENVIRONMENTAL REMED	SO	4,929	129	1,352	361	627	2,192	269	0	-
1823910	ENVIR CST UNDR AMORT	103440	WASHINGTON NON-DEFERRED COSTS	WA	(8)	-	-	(8)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	103445	American Barrel (UT)	SO	272	7	75	20	35	121	15	0	-
1823910	ENVIR CST UNDR AMORT	103446	Astoria/Unocal (Downtown)	SO	800	21	219	59	102	356	44	0	-
1823910	ENVIR CST UNDR AMORT	103447	Big Fork Hydro Plant (MT)	SO	732	19	201	54	93	326	40	0	-
1823910	ENVIR CST UNDR AMORT	103448	Bridger Coal Fuel Oil Spill	SO	501	13	137	37	64	223	27	0	-
1823910	ENVIR CST UNDR AMORT	103449	Bridger FGD Pond 1 Closure	SO	518	14	142	38	66	231	28	0	-
1823910	ENVIR CST UNDR AMORT	103450	Bridger Plant Oil Spills	SO	327	9	90	24	42	146	18	0	-
1823910	ENVIR CST UNDR AMORT	103451	Cedar Stream Plant (UT)	SO	45	1	12	3	6	20	2	0	-
1823910	ENVIR CST UNDR AMORT	103452	Dave Johnston Oil Spill	SO	434	11	119	32	55	193	24	0	-
1823910	ENVIR CST UNDR AMORT	103453	Eugene MGP (50% PCRP)	SO	229	6	63	17	29	102	12	0	-
1823910	ENVIR CST UNDR AMORT	103454	Everett MGP (2/3 PCRP)	SO	11	0	3	1	1	5	1	0	-
1823910	ENVIR CST UNDR AMORT	103455	Hunter Fuel Oil Spills	SO	34	1	9	2	4	15	2	0	-
1823910	ENVIR CST UNDR AMORT	103456	Huntington Ash Landfill	SO	886	23	243	65	113	394	48	0	-
1823910	ENVIR CST UNDR AMORT	103457	Idaho Falls Pole Yard	SO	1,272	33	349	93	162	566	69	0	-
1823910	ENVIR CST UNDR AMORT	103458	Jordan Plant Substation	SO	118	3	32	9	15	53	6	0	-
1823910	ENVIR CST UNDR AMORT	103459	Little Mountain Gas Plant	SO	172	5	47	13	22	77	9	0	-
1823910	ENVIR CST UNDR AMORT	103460	Montague Ranch (CA)	SO	21	1	6	2	3	10	1	0	-
1823910	ENVIR CST UNDR AMORT	103461	Naughton FGD Pond Closure	SO	79	2	22	6	10	35	4	0	-
1823910	ENVIR CST UNDR AMORT	103462	Ogden MGP	SO	1,607	42	441	118	204	715	88	0	-
1823910	ENVIR CST UNDR AMORT	103465	Tacoma A St. (25% PCRP)	SO	47	1	13	3	6	21	3	0	-
1823910	ENVIR CST UNDR AMORT	103466	Portland Harbor Service Ctr	SO	5,093	134	1,397	373	648	2,264	278	0	-
1823910	ENVIR CST UNDR AMORT	103467	Wyodak Fuel Oil Spill	SO	88	2	24	6	11	39	5	0	-
1823910	ENVIR CST UNDR AMORT	103585	CLINE FALLS-HYDRO	SO	10	0	3	1	1	5	1	0	-
1823910	ENVIR CST UNDR AMORT	103737	Geneva Rock Bldg - Hunter Plant	SO	3	0	1	0	0	2	0	0	-
1823910	ENVIR CST UNDR AMORT	103851	Alturas Service Center (CA)	SO	2	0	1	0	0	1	0	0	-
1823910	ENVIR CST UNDR AMORT	103852	Pendleton Service Center (OR)	SO	1	0	0	0	0	0	0	0	-
1823910	ENVIR CST UNDR AMORT	103853	Sunnyside Service Center (WA)	SO	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	-

PACIFICORP

Regulatory Assets (Actuals)
Year End: 06/2023
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	103941	D-SM Retail Minor Sites - RMP - 2013	SO	3	0	1	0	0	1	0	0	-
1823910	ENVIR CST UNDR AMORT	103942	D-SM Retail Minor Sites - RMP - 2014	SO	110	3	30	8	14	49	6	0	-
1823910	ENVIR CST UNDR AMORT	103948	WASHINGTON NON-DEFERRED COSTS-SPPC PACIF	WA	(52)	-	-	(52)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	103949	WASHINGTON NON-DEFERRED COSTS-SPPC ROCKY	WA	(38)	-	-	(38)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	103950	WASHINGTON NON-DEFERRED COSTS-REMEDIATIO	WA	(50)	-	-	(50)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	103951	WASHINGTON NON-DEFERRED COSTS-REMEDIATIO	WA	(228)	-	-	(228)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	103952	WASHINGTON NON-DEFERRED COSTS-REMEDIATIO	WA	(36)	-	-	(36)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	103955	Wash Non-Def Costs - SPPC - RMP - 2014	WA	(54)	-	-	(54)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	103961	D-SM RETAIL MINOR SITES - RMP	SO	3,453	91	947	253	439	1,535	188	0	-
1823910	ENVIR CST UNDR AMORT	104072	FREEPORT SUBSTATION	SO	34	1	9	2	4	15	2	0	-
1823910	ENVIR CST UNDR AMORT	104108	Bors Property (OR) - 2016	SO	9	0	2	1	1	4	0	0	-
1823910	ENVIR CST UNDR AMORT	104112	Carbon Ash Spill (UT) - 2016	SO	2,049	54	562	150	261	911	112	0	-
1823910	ENVIR CST UNDR AMORT	104143	Hunter Fuel Oil Spills - 2017	SO	1	0	0	0	0	0	0	0	-
1823910	ENVIR CST UNDR AMORT	104144	Naughton Oil Spill	SO	11	0	3	1	1	5	1	0	-
1823910	ENVIR CST UNDR AMORT	104175	Ririe Substation	SO	5	0	1	0	1	2	0	0	-
1823910	ENVIR CST UNDR AMORT	104197	Bridger Plant - FGD Pond 1	SO	2,753	72	755	201	350	1,224	150	0	-
1823910	ENVIR CST UNDR AMORT	104198	Bridger Plant - FGD Pond 2	SO	27	1	8	2	3	12	1	0	-
1823910	ENVIR CST UNDR AMORT	104199	Naughton Plant - FGD Pond 1	SO	6,152	161	1,687	450	782	2,736	335	0	-
1823910	ENVIR CST UNDR AMORT	104200	Naughton Plant - FGD Pond 2	SO	4,716	124	1,293	345	600	2,097	257	0	-
1823910	ENVIR CST UNDR AMORT	104201	Huntington Plant Ash Landfill	SO	551	14	151	40	70	245	30	0	-
1823910	ENVIR CST UNDR AMORT	104202	Dave Johnston Pond 4A & 4B	SO	2,548	67	699	186	324	1,133	139	0	-
1823910	ENVIR CST UNDR AMORT	104203	Colstrip Pond	SO	2,989	78	820	219	380	1,329	163	0	-
1823910	ENVIR CST UNDR AMORT	104204	Cholla Ash-Flyash Pond	SO	810	21	222	59	103	360	44	0	-
1823910	ENVIR CST UNDR AMORT	104205	Naughton North Ash Pond	SO	3	0	1	0	0	1	0	0	-
1823910	ENVIR CST UNDR AMORT	104206	Naughton South Ash Pond	SO	39	1	11	3	5	17	2	0	-
1823910	ENVIR CST UNDR AMORT	104210	American Barrel (UT)-WA	WA	(15)	-	-	(15)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104211	Astoria/Unocal (Downtown)-WA	WA	(43)	-	-	(43)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104212	ASTORIA YOUNGS BAY CLEANUP-WA	WA	(30)	-	-	(30)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104213	Big Fork Hydro Plant (MT)-WA	WA	(39)	-	-	(39)	-	-	-	-	-
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	(29)	-	-	(29)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104216	Bridger FGD Pond 1 Closure-WA	WA	(25)	-	-	(25)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104218	Bridger Plant - FGD Pond 1-WA	WA	(187)	-	-	(187)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104219	Bridger Plant - FGD Pond 2-WA	WA	(2)	-	-	(2)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104220	Bridger Plant Oil Spills-2018	WA	(17)	-	-	(17)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104221	Carbon Ash Spill (UT) - WA	WA	(55)	-	-	(55)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104222	Cedar Steam - WA	WA	(3)	-	-	(3)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104223	Colstrip Pond - WA	WA	(202)	-	-	(202)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104224	Cholla Ash - WA	WA	(54)	-	-	(54)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104225	DJ Oil Spill - WA	WA	(10)	-	-	(10)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104226	DJ 4A&4B - WA	WA	(172)	-	-	(172)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104227	Eugene MGP (50%PCRP) - WA	WA	(13)	-	-	(13)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104228	Everett MGP (2/3 PCRP) - WA	WA	(1)	-	-	(1)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104229	Hunter Plant - WA	WA	(41)	-	-	(41)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104230	Huntington Ash- WA	WA	(56)	-	-	(56)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104231	Idaho Falls Pole Yard- WA	WA	(69)	-	-	(69)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104232	Jordan Plant Substation- WA	WA	(6)	-	-	(6)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104233	Montague Ranch - WA	WA	(0)	-	-	(0)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104234	Naughton Plant FGDP 1 - WA	WA	(413)	-	-	(413)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104235	Naughton Plant FGDP 2 - WA	WA	(316)	-	-	(316)	-	-	-	-	-

PACIFICORP

Regulatory Assets (Actuals)
Year End: 06/2023
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	104236	Naughton Plant FGDP Closure - WA	WA	(3)	-	-	(3)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104237	Naughton Oil Spill - WA	WA	(0)	-	-	(0)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104238	Naughton North Ash Pond - WA	WA	(0)	-	-	(0)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104239	Naughton South Ash Pond - WA	WA	(3)	-	-	(3)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104240	Ogden MGP - WA	WA	(73)	-	-	(73)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104241	Olympia - WA	WA	(0)	-	-	(0)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104242	Portland Harbor Srce Cntrl - WA	WA	(311)	-	-	(311)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104244	Silver Bell/Telluride - WA	WA	(246)	-	-	(246)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104245	Tacoma A St. (25% PCRP) - WA	WA	(3)	-	-	(3)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104246	Utah Metal East - WA	WA	(0)	-	-	(0)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104247	Wyodak Oil Spill - WA	WA	(5)	-	-	(5)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104248	Hunter Fuel Oil Spill-WA	WA	(0)	-	-	(0)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104268	Rocky Mountain - WA	WA	(193)	-	-	(193)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104269	Pac Power - WA	WA	(224)	-	-	(224)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104274	Hayden Ash Landfill	SO	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	-
1823910	ENVIR CST UNDR AMORT	104275	Hayden Ash Landfill - WA	WA	0	-	-	0	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104296	NTO Parking Lot-Asbestos 2018	SO	119	3	33	9	15	53	6	0	-
1823910	ENVIR CST UNDR AMORT	104297	NTO Parking Lot Asbestos - WA 2018	WA	(9)	-	-	(9)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104394	Klamath Falls	SO	1,676	44	460	123	213	745	91	0	-
1823910	ENVIR CST UNDR AMORT	104395	Klamath Falls - WA 2021	WA	(114)	-	-	(114)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104399	Portland Harbor Service Insurance	SO	(708)	(19)	(194)	(52)	(90)	(315)	(39)	(0)	-
1823910	ENVIR CST UNDR AMORT	104404	North Temple Office	SO	1,256	33	344	92	160	558	68	0	-
1823910	ENVIR CST UNDR AMORT	104405	North Temple Office WA	WA	(84)	-	-	(84)	-	-	-	-	-
1823910	ENVIR CST UNDR AMORT	104408	American Barrel (UT) - 2022	SO	271	7	74	20	34	121	15	0	-
1823910	ENVIR CST UNDR AMORT	104409	American Barrel (UT)-WA 2022	WA	(18)	-	-	(18)	-	-	-	-	-
1823910 Total					**48,019**	**1,353**	**14,142**	**225**	**6,558**	**22,929**	**2,812**	**0**	**-**
1823920	DSR COSTS AMORTIZED	0	DSR COST AMORT	OTHER	410,553	-	-	-	-	-	-	-	410,553
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

Regulatory Assets (Actuals)
Year End: 06/2023
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	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
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

PACIFICORP

Regulatory Assets (Actuals)
Year End: 06/2023
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	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
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

PACIFICORP

Regulatory Assets (Actuals)
Year End: 06/2023
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	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
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

PACIFICORP

Regulatory Assets (Actuals)
Year End: 06/2023
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

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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
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

PACIFICORP

Regulatory Assets (Actuals)
Year End: 06/2023
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

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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
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

PACIFICORP

Regulatory Assets (Actuals)
Year End: 06/2023
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

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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
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

PACIFICORP

Regulatory Assets (Actuals)
Year End: 06/2023
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	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
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

PACIFICORP

Regulatory Assets (Actuals)
Year End: 06/2023
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

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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
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

PACIFICORP

Regulatory Assets (Actuals)
Year End: 06/2023
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	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
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

PACIFICORP

Regulatory Assets (Actuals)
Year End: 06/2023
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	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
1823920	DSR COSTS AMORTIZED	104111	WY DSM - 186065 Clear Acct Balance	OTHER	(1,405)	-	-	-	-	-	-	-	(1,405)
1823920 Total					**369,897**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**369,897**
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

PACIFICORP

Regulatory Assets (Actuals)
Year End: 06/2023
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

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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
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

PACIFICORP

Regulatory Assets (Actuals)
Year End: 06/2023
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

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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

PACIFICORP

Regulatory Assets (Actuals)
Year End: 06/2023
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

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1823930	DSR COSTS NOT AMORT	104016	IRRIGATION EFFICIENCY PRGRM - ID 2016	OTHER	80	-	-	-	-	-	-	-	80
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	138015	Reg Asset Current - Energy West Mining	SE	968	12	255	66	144	433	58	0	-
1823990	OTHR REG ASSET-N CST	138020	Reg Asset Current - DSM	OTHER	411	-	-	-	-	-	-	-	411
1823990	OTHR REG ASSET-N CST	138045	Reg Asset Current - GHG Allowances	OTHER	5,639	-	-	-	-	-	-	-	5,639
1823990	OTHR REG ASSET-N CST	138050	Reg Asset Current - Def Net Power Costs	OTHER	304,547	-	-	-	-	-	-	-	304,547
1823990	OTHR REG ASSET-N CST	138055	Reg Asset Current - Def RECs in Rates	OTHER	117	-	-	-	-	-	-	-	117
1823990	OTHR REG ASSET-N CST	138060	Reg Asset Current - BPA Balancing Accts	OTHER	3,913	-	-	-	-	-	-	-	3,913
1823990	OTHR REG ASSET-N CST	138075	Reg Asset Current - Wildfire Mitigation	OTHER	39,972	-	-	-	-	-	-	-	39,972
1823990	OTHR REG ASSET-N CST	138090	Reg Asset Current - Solar Feed-In	OTHER	4,438	-	-	-	-	-	-	-	4,438
1823990	OTHR REG ASSET-N CST	138190	Reg Asset Current - Other	OTHER	13,813	-	-	-	-	-	-	-	13,813
1823990	OTHR REG ASSET-N CST	186100	Calif Alternative Rate for Energy (CARE)	OTHER	452	-	-	-	-	-	-	-	452
1823990	OTHR REG ASSET-N CST	186119	Reg Asset - DSM - CA - Balance Reclass	OTHER	142	-	-	-	-	-	-	-	142
1823990	OTHR REG ASSET-N CST	186129	Reg Asset - DSM - ID - Balance Reclass	OTHER	1,457	-	-	-	-	-	-	-	1,457
1823990	OTHR REG ASSET-N CST	186137	RegA - DSM - OR - Reclass to Current	OTHER	(411)	-	-	-	-	-	-	-	(411)
1823990	OTHR REG ASSET-N CST	186159	Reg Asset - DSM - WA - Balance Reclass	OTHER	3,150	-	-	-	-	-	-	-	3,150
1823990	OTHR REG ASSET-N CST	186793	RegA - Deer Creek - OR - Recl to Curr	SE	(575)	(7)	(152)	(39)	(85)	(257)	(35)	(0)	-
1823990	OTHR REG ASSET-N CST	187042	Reg Asset - CA GHG Allowances	OTHER	5,639	-	-	-	-	-	-	-	5,639
1823990	OTHR REG ASSET-N CST	187048	RegA - CA GHG Allowances - Recl to Curr	OTHER	(5,639)	-	-	-	-	-	-	-	(5,639)
1823990	OTHR REG ASSET-N CST	187230	RegA - Oregon OCAT Expense Deferral	OTHER	(527)	-	-	-	-	-	-	-	(527)
1823990	OTHR REG ASSET-N CST	187231	Reg Asset - Oregon Metro BIT	OTHER	19	-	-	-	-	-	-	-	19
1823990	OTHR REG ASSET-N CST	187239	RegA-Income Tax Related-Recl to Liab	OTHER	527	-	-	-	-	-	-	-	527
1823990	OTHR REG ASSET-N CST	187255	RegA - BPA Balancing Accts - Recl to Cur	OTHER	(3,913)	-	-	-	-	-	-	-	(3,913)
1823990	OTHR REG ASSET-N CST	187300	CA - Jan 2010 Storm Costs	OTHER	(202)	-	-	-	-	-	-	-	(202)
1823990	OTHR REG ASSET-N CST	187302	RegA-OR Low Income Bill Discount	OTHER	3,330	-	-	-	-	-	-	-	3,330
1823990	OTHR REG ASSET-N CST	187303	RegA-OR Low Income Bill Disc Admin Cost	OTHER	55	-	-	-	-	-	-	-	55
1823990	OTHR REG ASSET-N CST	187304	RegA-CA Emerg Svc Prgms-Battery Storage	OTHER	(228)	-	-	-	-	-	-	-	(228)
1823990	OTHR REG ASSET-N CST	187308	RegA - WY Low-Carbon Energy Standards	OTHER	72	-	-	-	-	-	-	-	72
1823990	OTHR REG ASSET-N CST	187309	RegA-OR Utility Community Advisory Group	OTHER	136	-	-	-	-	-	-	-	136
1823990	OTHR REG ASSET-N CST	187320	Reg Asset - Deprec Increase - ID	IDU	8,713	-	-	-	-	-	8,713	-	-
1823990	OTHR REG ASSET-N CST	187321	Reg Asset - Deprec Increase - UT	UT	1,024	-	-	-	-	1,024	-	-	-
1823990	OTHR REG ASSET-N CST	187322	Reg Asset - Deprec Increase - WY	WYP	14,420	-	-	-	14,420	-	-	-	-
1823990	OTHR REG ASSET-N CST	187332	Reg Asset - Carbon Unrec Plant - UT	UT	12,337	-	-	-	-	12,337	-	-	-
1823990	OTHR REG ASSET-N CST	187338	REG ASSET - CARBON PLT DECOM/INVENTORY	CA	(52)	(52)	-	-	-	-	-	-	-
1823990	OTHR REG ASSET-N CST	187338	REG ASSET - CARBON PLT DECOM/INVENTORY	IDU	(99)	-	-	-	-	-	(99)	-	-
1823990	OTHR REG ASSET-N CST	187338	REG ASSET - CARBON PLT DECOM/INVENTORY	OR	(449)	-	(449)	-	-	-	-	-	-
1823990	OTHR REG ASSET-N CST	187338	REG ASSET - CARBON PLT DECOM/INVENTORY	SG	3,446	47	927	258	475	1,547	193	0	-
1823990	OTHR REG ASSET-N CST	187338	REG ASSET - CARBON PLT DECOM/INVENTORY	UT	(1,517)	-	-	-	-	(1,517)	-	-	-
1823990	OTHR REG ASSET-N CST	187338	REG ASSET - CARBON PLT DECOM/INVENTORY	WA	(278)	-	-	(278)	-	-	-	-	-
1823990	OTHR REG ASSET-N CST	187338	REG ASSET - CARBON PLT DECOM/INVENTORY	WYU	(420)	-	-	-	(420)	-	-	-	-
1823990	OTHR REG ASSET-N CST	187345	Reg Asset - UT - Pref Stock Redemp Loss	OTHER	58	-	-	-	-	-	-	-	58

PACIFICORP

Regulatory Assets (Actuals)
Year End: 06/2023
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	187346	Reg Asset - WY - Pref Stock Redemp Loss	OTHER	20	-	-	-	-	-	-	-	20
1823990	OTHR REG ASSET-N CST	187347	Reg Asset - WA - Pref Stock Redemp Loss	OTHER	9	-	-	-	-	-	-	-	9
1823990	OTHR REG ASSET-N CST	187350	ID - Deferred Overburden Costs	OTHER	685	-	-	-	-	-	-	-	685
1823990	OTHR REG ASSET-N CST	187351	WY - Deferred Overburden Costs	WYP	1,679	-	-	-	1,679	-	-	-	-
1823990	OTHR REG ASSET-N CST	187353	RegA-OR Distribution System Plan	OTHER	1,495	-	-	-	-	-	-	-	1,495
1823990	OTHR REG ASSET-N CST	187354	RegA-OR 2020 GRC-Meters Replcd by AMI	OTHER	9,487	-	-	-	-	-	-	-	9,487
1823990	OTHR REG ASSET-N CST	187357	CA Mobile Home Park Conversion (MHPCBA)	OTHER	200	-	-	-	-	-	-	-	200
1823990	OTHR REG ASSET-N CST	187358	Reg Asset - UT MPA Balancing Account	OTHER	0	-	-	-	-	-	-	-	0
1823990	OTHR REG ASSET-N CST	187361	Reg A-OR-COVID-19 Bill Assistance Prog	OTHER	11,927	-	-	-	-	-	-	-	11,927
1823990	OTHR REG ASSET-N CST	187362	Reg A-WA-COVID-19 Bill Assistance Prog	OTHER	3,101	-	-	-	-	-	-	-	3,101
1823990	OTHR REG ASSET-N CST	187369	RegA -WA Equity Advisory Group (CETA)	OTHER	1,032	-	-	-	-	-	-	-	1,032
1823990	OTHR REG ASSET-N CST	187380	Reg Asset - UT Solar Incentive Program	OTHER	(447)	-	-	-	-	-	-	-	(447)
1823990	OTHR REG ASSET-N CST	187383	RegA - OR Solar Feed-In - Recl to Curr	OTHER	(4,300)	-	-	-	-	-	-	-	(4,300)
1823990	OTHR REG ASSET-N CST	187384	RegA - UT Solar Feed-In - Recl to Curr	OTHER	(138)	-	-	-	-	-	-	-	(138)
1823990	OTHR REG ASSET-N CST	187387	Reg Asset-Utah STEP Pilot Prog Bal Acct	OTHER	(6,479)	-	-	-	-	-	-	-	(6,479)
1823990	OTHR REG ASSET-N CST	187390	UT-Klamath Hydro Relicensing Costs	OTHER	(0)	-	-	-	-	-	-	-	(0)
1823990	OTHR REG ASSET-N CST	187392	Reg Asset-OR Solar Feed-In Tariff 2022	OTHER	1,327	-	-	-	-	-	-	-	1,327
1823990	OTHR REG ASSET-N CST	187394	RegA - UT Solar Feed-In - Recl to Liab	OTHER	7,389	-	-	-	-	-	-	-	7,389
1823990	OTHR REG ASSET-N CST	187395	Reg Asset-OR Solar Feed-In Tariff 2023	OTHER	2,217	-	-	-	-	-	-	-	2,217
1823990	OTHR REG ASSET-N CST	187415	Reg Asset-UT Subscriber Solar Program	OTHER	1,865	-	-	-	-	-	-	-	1,865
1823990	OTHR REG ASSET-N CST	187420	RegA - OR Community Solar	OTHER	2,973	-	-	-	-	-	-	-	2,973
1823990	OTHR REG ASSET-N CST	187495	RegA - Other - Recl to Curr	OTHER	(13,813)	-	-	-	-	-	-	-	(13,813)
1823990	OTHR REG ASSET-N CST	187648	Reg A - Post-Retirement - Recl to Curr	SE	(393)	(5)	(103)	(27)	(58)	(176)	(24)	(0)	-
1823990	OTHR REG ASSET-N CST	187651	RegA-OR TB Flats	OTHER	6,889	-	-	-	-	-	-	-	6,889
1823990	OTHR REG ASSET-N CST	187652	RegA-OR Cedar Springs II	OTHER	275	-	-	-	-	-	-	-	275
1823990	OTHR REG ASSET-N CST	187658	RegA-WA Insurance Reserves-Recl to Liab	OTHER	318	-	-	-	-	-	-	-	318
1823990	OTHR REG ASSET-N CST	187659	RegA-CA Insurance Reserves-Recl to Liab	OTHER	3,367	-	-	-	-	-	-	-	3,367
1823990	OTHR REG ASSET-N CST	187660	RegA-OR Transp Electrification Pilot	OTHER	2,723	-	-	-	-	-	-	-	2,723
1823990	OTHR REG ASSET-N CST	187661	RegA-UT Elec Vehicle Charging Infrast	OTHER	(7,326)	-	-	-	-	-	-	-	(7,326)
1823990	OTHR REG ASSET-N CST	187662	RegA-CA Transp Electrification Pilot	OTHER	(236)	-	-	-	-	-	-	-	(236)
1823990	OTHR REG ASSET-N CST	187664	RegA-WA Transp Electrification Pilot	OTHER	820	-	-	-	-	-	-	-	820
1823990	OTHR REG ASSET-N CST	187665	RegA-OR Residential Charging Pilot	OTHER	(3,270)	-	-	-	-	-	-	-	(3,270)
1823990	OTHR REG ASSET-N CST	187831	Reg Asset - UT RBA CY2022	OTHER	(389)	-	-	-	-	-	-	-	(389)
1823990	OTHR REG ASSET-N CST	187833	Reg Asset - UT RBA CY2023	OTHER	(3,062)	-	-	-	-	-	-	-	(3,062)
1823990	OTHR REG ASSET-N CST	187860	Reg Asset - WY RRA CY2022	OTHER	(139)	-	-	-	-	-	-	-	(139)
1823990	OTHR REG ASSET-N CST	187861	Reg Asset - WY RRA CY2023	OTHER	(1,009)	-	-	-	-	-	-	-	(1,009)
1823990	OTHR REG ASSET-N CST	187885	Reg Asset - WY RRA CY2021	OTHER	(112)	-	-	-	-	-	-	-	(112)
1823990	OTHR REG ASSET-N CST	187886	Reg Asset-OR RPS Compliance Purchases	OTHER	117	-	-	-	-	-	-	-	117
1823990	OTHR REG ASSET-N CST	187894	RegA - OR RECs in Rates - Recl to Curr	OTHER	(117)	-	-	-	-	-	-	-	(117)
1823990	OTHR REG ASSET-N CST	187897	RegA - UT RECs in Rates - Recl to Liab	OTHER	3,451	-	-	-	-	-	-	-	3,451
1823990	OTHR REG ASSET-N CST	187899	RegA - WY RECs in Rates - Recl to Liab	OTHER	1,260	-	-	-	-	-	-	-	1,260
1823990	OTHR REG ASSET-N CST	187911	REG ASSET - LAKE SIDE LIQ. DAMAGES - WY	WYP	663	-	-	-	663	-	-	-	-
1823990	OTHR REG ASSET-N CST	187913	Reg Asset - Goodnoe Hills Liq. Damages -	WYP	223	-	-	-	223	-	-	-	-
1823990	OTHR REG ASSET-N CST	187914	"Reg Asset-UT-Liq. Damages JB4, N1&2"	UT	367	-	-	-	-	367	-	-	-
1823990	OTHR REG ASSET-N CST	187915	Reg Asset-WY-Liq. Damages N2	WYP	60	-	-	-	60	-	-	-	-
1823990	OTHR REG ASSET-N CST	187916	Reg Asset-WY Wind Test Energy Deferral	WYU	210	-	-	-	210	-	-	-	-
1823990	OTHR REG ASSET-N CST	187952	DEFERRED INTERVENER	OTHER	0	-	-	-	-	-	-	-	0
1823990	OTHR REG ASSET-N CST	187956	CA DEFERRED INTERVENOR FUNDING	OTHER	417	-	-	-	-	-	-	-	417
1823990	OTHR REG ASSET-N CST	187957	DEFERRED OR INDEPENDENT EVALUATOR FEES	OTHER	116	-	-	-	-	-	-	-	116
1823990	OTHR REG ASSET-N CST	187958	ID Deferred Intervenor Funding	IDU	40	-	-	-	-	-	40	-	-

PACIFICORP

Regulatory Assets (Actuals)
Year End: 06/2023
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	187964	RegA - Intervenor Fees - Recl to Liab	OTHER	186	-	-	-	-	-	-	-	186
1823990	OTHR REG ASSET-N CST	187967	RegA - OR Asset Sale Gain-Balance Recl	OTHER	3,203	-	-	-	-	-	-	-	3,203
1823990	OTHR REG ASSET-N CST	187968	Reg A - Insurance Reserves - Reclass	OTHER	31,639	-	-	-	-	-	-	-	31,639
1823990	OTHR REG ASSET-N CST	187975	Reg Asset - CA ECAC	OTHER	(4,027)	-	-	-	-	-	-	-	(4,027)
1823990	OTHR REG ASSET-N CST	187989	Reg Asset - OR PCAM FY2021	OTHER	51,650	-	-	-	-	-	-	-	51,650
1823990	OTHR REG ASSET-N CST	189001	RegA-CA Fire Risk Mitigation (FRMMA)	OTHER	393	-	-	-	-	-	-	-	393
1823990	OTHR REG ASSET-N CST	189002	RegA-CA Wildfire Mitigation Plan(WMPMA)	OTHER	34,661	-	-	-	-	-	-	-	34,661
1823990	OTHR REG ASSET-N CST	189003	Contra RegA-CA Fire/Wildlife Mitigation	OTHER	(1,886)	-	-	-	-	-	-	-	(1,886)
1823990	OTHR REG ASSET-N CST	189004	RegA-CA Fire Hazard Prevention (FHPMA)	OTHER	3,052	-	-	-	-	-	-	-	3,052
1823990	OTHR REG ASSET-N CST	189005	RegA-CA Wildfire/Natl Disaster (WNDRR)	OTHER	86	-	-	-	-	-	-	-	86
1823990	OTHR REG ASSET-N CST	189006	RegA-CA Emerg Cust Protections (ECPMA)	OTHER	6	-	-	-	-	-	-	-	6
1823990	OTHR REG ASSET-N CST	189011	Reg Asset-UT Wildland Fire Protection	OTHER	8,664	-	-	-	-	-	-	-	8,664
1823990	OTHR REG ASSET-N CST	189016	Reg Asset-OR Wildfire Mitigation Acct	OTHER	34,441	-	-	-	-	-	-	-	34,441
1823990	OTHR REG ASSET-N CST	189017	RegA-OR Wildfire – Damaged Asset NBV	OR	1,878	-	1,878	-	-	-	-	-	-
1823990	OTHR REG ASSET-N CST	189018	RegA-OR Wildfire Risk/Veg Mgmt (WMVM)	OTHER	4,446	-	-	-	-	-	-	-	4,446
1823990	OTHR REG ASSET-N CST	189019	RegA-OR Wildfire WMVM 2022	OTHER	25,927	-	-	-	-	-	-	-	25,927
1823990	OTHR REG ASSET-N CST	189020	Contra RegA-OR Wildfire Mitigation	OTHER	(1,296)	-	-	-	-	-	-	-	(1,296)
1823990	OTHR REG ASSET-N CST	189029	RegA-Wildfire Mitigation - Recl to Curr	OTHER	(39,972)	-	-	-	-	-	-	-	(39,972)
1823990	OTHR REG ASSET-N CST	189030	Klamath Unrecovered Plant and Transfer	SG	5,178	71	1,392	388	713	2,324	290	0	-
1823990	OTHR REG ASSET-N CST	189506	Reg Asset - CA ECAC CY2022	OTHER	9,161	-	-	-	-	-	-	-	9,161
1823990	OTHR REG ASSET-N CST	189507	Contra Reg Asset - CA ECAC CY2022	OTHER	(459)	-	-	-	-	-	-	-	(459)
1823990	OTHR REG ASSET-N CST	189508	Reg Asset - CA ECAC CY2023	OTHER	8,441	-	-	-	-	-	-	-	8,441
1823990	OTHR REG ASSET-N CST	189509	Contra Reg Asset - CA ECAC CY2023	OTHER	(422)	-	-	-	-	-	-	-	(422)
1823990	OTHR REG ASSET-N CST	189529	RegA - CA Def Exc NPC - Recl to Liab	OTHER	4,027	-	-	-	-	-	-	-	4,027
1823990	OTHR REG ASSET-N CST	189537	Reg Asset-ID ECAM CY 2022	OTHER	29,529	-	-	-	-	-	-	-	29,529
1823990	OTHR REG ASSET-N CST	189538	Reg Asset-ID ECAM CY 2023	OTHER	24,874	-	-	-	-	-	-	-	24,874
1823990	OTHR REG ASSET-N CST	189547	Contra Reg Asset - ID ECAM CY 2022	OTHER	(1,617)	-	-	-	-	-	-	-	(1,617)
1823990	OTHR REG ASSET-N CST	189548	Contra Reg Asset - ID ECAM CY 2023	OTHER	(1,244)	-	-	-	-	-	-	-	(1,244)
1823990	OTHR REG ASSET-N CST	189568	RegA - ID Def Exc NPC - Recl to Curr	OTHER	(29,984)	-	-	-	-	-	-	-	(29,984)
1823990	OTHR REG ASSET-N CST	189586	Reg Asset - OR PCAM FY2022	OTHER	125,919	-	-	-	-	-	-	-	125,919
1823990	OTHR REG ASSET-N CST	189587	Contra Reg Asset - OR PCAM FY2022	OTHER	(57,715)	-	-	-	-	-	-	-	(57,715)
1823990	OTHR REG ASSET-N CST	189588	Reg Asset - OR PCAM CY2023	OTHER	59,262	-	-	-	-	-	-	-	59,262
1823990	OTHR REG ASSET-N CST	189589	Contra Reg Asset - OR PCAM CY2023	OTHER	(59,262)	-	-	-	-	-	-	-	(59,262)
1823990	OTHR REG ASSET-N CST	189598	RegA - OR Def Exc NPC - Recl to Curr	OTHER	(18,036)	-	-	-	-	-	-	-	(18,036)
1823990	OTHR REG ASSET-N CST	189610	Reg Asset - UT EBA CY2020	OTHER	2,045	-	-	-	-	-	-	-	2,045
1823990	OTHR REG ASSET-N CST	189611	Reg Asset - UT EBA CY2021	OTHER	1,000	-	-	-	-	-	-	-	1,000
1823990	OTHR REG ASSET-N CST	189612	Reg Asset - UT EBA CY2022	OTHER	173,331	-	-	-	-	-	-	-	173,331
1823990	OTHR REG ASSET-N CST	189613	Reg Asset - UT EBA CY2023	OTHER	160,173	-	-	-	-	-	-	-	160,173
1823990	OTHR REG ASSET-N CST	189622	Contra Reg Asset - UT EBA CY2022	OTHER	(8,667)	-	-	-	-	-	-	-	(8,667)
1823990	OTHR REG ASSET-N CST	189623	Contra Reg Asset - UT EBA CY2023	OTHER	(8,009)	-	-	-	-	-	-	-	(8,009)
1823990	OTHR REG ASSET-N CST	189638	RegA - UT Def Exc NPC - Recl to Curr	OTHER	(167,709)	-	-	-	-	-	-	-	(167,709)
1823990	OTHR REG ASSET-N CST	189642	Reg Asset-WA-Major Mtc Exp-Colstrip U4	WA	259	-	-	259	-	-	-	-	-
1823990	OTHR REG ASSET-N CST	189644	Reg Asset - WA PCAM PTC CY2023	OTHER	(452)	-	-	-	-	-	-	-	(452)
1823990	OTHR REG ASSET-N CST	189645	Reg Asset - WA PCAM CY2023	OTHER	36,504	-	-	-	-	-	-	-	36,504
1823990	OTHR REG ASSET-N CST	189646	Contra Reg Asset - WA PCAM CY2023	OTHER	(1,825)	-	-	-	-	-	-	-	(1,825)
1823990	OTHR REG ASSET-N CST	189648	RegA - WA Def Exc NPC - Recl to Curr	OTHER	(19,882)	-	-	-	-	-	-	-	(19,882)
1823990	OTHR REG ASSET-N CST	189649	RegA - WA Def Exc NPC - Recl to Liab	OTHER	90,367	-	-	-	-	-	-	-	90,367
1823990	OTHR REG ASSET-N CST	189651	Reg Asset - WY ECAM CY2021	OTHER	(1,671)	-	-	-	-	-	-	-	(1,671)
1823990	OTHR REG ASSET-N CST	189652	Reg Asset - WY ECAM CY2022	OTHER	74,323	-	-	-	-	-	-	-	74,323
1823990	OTHR REG ASSET-N CST	189653	Reg Asset - WY ECAM CY2023	OTHER	48,397	-	-	-	-	-	-	-	48,397

PACIFICORP

Regulatory Assets (Actuals)
Year End: 06/2023
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	189662	Contra Reg Asset - WY ECAM CY2022	OTHER	(3,716)	-	-	-	-	-	-	-	(3,716)
1823990	OTHR REG ASSET-N CST	189663	Contra Reg Asset - WY ECAM CY2023	OTHER	(2,420)	-	-	-	-	-	-	-	(2,420)
1823990	OTHR REG ASSET-N CST	189688	RegA - WY Def Exc NPC - Recl to Curr	OTHER	(68,935)	-	-	-	-	-	-	-	(68,935)
1823990 Total					**993,793**	**67**	**3,748**	**627**	**18,023**	**16,082**	**9,136**	**0**	**946,110**
1823999	REGULATORY ASST-OTH	186011	DSM Reg Asset - Accruals - CA	OTHER	183	-	-	-	-	-	-	-	183
1823999	REGULATORY ASST-OTH	186015	DSM Reg Asset - Balancing Acct - CA	OTHER	(325)	-	-	-	-	-	-	-	(325)
1823999	REGULATORY ASST-OTH	186021	DSM Reg Asset - Accruals - ID	OTHER	240	-	-	-	-	-	-	-	240
1823999	REGULATORY ASST-OTH	186025	DSM Reg Asset - Balancing Acct - ID	OTHER	(1,697)	-	-	-	-	-	-	-	(1,697)
1823999	REGULATORY ASST-OTH	186035	DSM Reg Asset - Balancing Acct - OR	OTHER	411	-	-	-	-	-	-	-	411
1823999	REGULATORY ASST-OTH	186041	DSM Reg Asset - Accruals - UT	OTHER	2,630	-	-	-	-	-	-	-	2,630
1823999	REGULATORY ASST-OTH	186045	DSM Reg Asset - Balancing Acct - UT	OTHER	(58,990)	-	-	-	-	-	-	-	(58,990)
1823999	REGULATORY ASST-OTH	186051	DSM Reg Asset - Accruals - WA	OTHER	1,149	-	-	-	-	-	-	-	1,149
1823999	REGULATORY ASST-OTH	186055	DSM Reg Asset - Balancing Acct - WA	OTHER	(4,298)	-	-	-	-	-	-	-	(4,298)
1823999	REGULATORY ASST-OTH	186061	DSM Reg Asset - Accruals - WY	OTHER	231	-	-	-	-	-	-	-	231
1823999	REGULATORY ASST-OTH	186065	DSM Reg Asset - Balancing Acct - WY	OTHER	(675)	-	-	-	-	-	-	-	(675)
1823999	REGULATORY ASST-OTH	186071	DSM Reg Asset - Accruals - WY Cat 1	OTHER	108	-	-	-	-	-	-	-	108
1823999	REGULATORY ASST-OTH	186075	DSM Reg Asset-Balancing Acct-WY Cat 1	OTHER	2,196	-	-	-	-	-	-	-	2,196
1823999	REGULATORY ASST-OTH	186081	DSM Reg Asset - Accruals - WY Cat 2	OTHER	47	-	-	-	-	-	-	-	47
1823999	REGULATORY ASST-OTH	186085	DSM Reg Asset-Balancing Acct-WY Cat 2	OTHER	(2,279)	-	-	-	-	-	-	-	(2,279)
1823999 Total					**(61,070)**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**(61,070)**
Grand Total					**1,701,924**	**13,554**	**140,632**	**29,335**	**110,949**	**212,735**	**33,133**	**0**	**1,161,588**

B17.DEPRECIATION RESERVE

PACIFICORP

Depreciation Reserve (Actuals)
Year End: 06/2023
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	(29,370)	(404)	(7,896)	(2,199)	(4,046)	(13,181)	(1,643)	(0)	-
1080000	AC PR DPR EL PL SR	3103000	WATER RIGHTS	SG	(14,473)	(199)	(3,891)	(1,084)	(1,994)	(6,496)	(810)	(0)	-
1080000	AC PR DPR EL PL SR	3110000	STRUCTURES AND IMPROVEMENTS	SG	(640,196)	(8,815)	(172,111)	(47,939)	(88,195)	(287,322)	(35,814)	(0)	-
1080000	AC PR DPR EL PL SR	3120000	BOILER PLANT EQUIPMENT	SG	(2,450,050)	(33,734)	(658,675)	(183,465)	(337,523)	(1,099,590)	(137,062)	(0)	-
1080000	AC PR DPR EL PL SR	3140000	TURBOGENERATOR UNITS	SG	(527,124)	(7,258)	(141,713)	(39,472)	(72,618)	(236,575)	(29,489)	(0)	-
1080000	AC PR DPR EL PL SR	3150000	ACCESSORY ELECTRIC EQUIPMENT	SG	(273,751)	(3,769)	(73,596)	(20,499)	(37,712)	(122,860)	(15,314)	(0)	-
1080000	AC PR DPR EL PL SR	3157000	ACCESSORY ELECTRIC EQUIP-SUPV & ALARM	SG	(36)	(0)	(10)	(3)	(5)	(16)	(2)	(0)	-
1080000	AC PR DPR EL PL SR	3160000	MISCELLANEOUS POWER PLANT EQUIPMENT	SG	(17,558)	(242)	(4,720)	(1,315)	(2,419)	(7,880)	(982)	(0)	-
1080000	AC PR DPR EL PL SR	3302000	LAND RIGHTS	SG-P	(4,156)	(57)	(1,117)	(311)	(572)	(1,865)	(232)	(0)	-
1080000	AC PR DPR EL PL SR	3302000	LAND RIGHTS	SG-U	(209)	(3)	(56)	(16)	(29)	(94)	(12)	(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	(111)	(2)	(30)	(8)	(15)	(50)	(6)	(0)	-
1080000	AC PR DPR EL PL SR	3304000	FLOOD RIGHTS	SG-P	(289)	(4)	(78)	(22)	(40)	(130)	(16)	(0)	-
1080000	AC PR DPR EL PL SR	3304000	FLOOD RIGHTS	SG-U	(87)	(1)	(23)	(6)	(12)	(39)	(5)	(0)	-
1080000	AC PR DPR EL PL SR	3305000	LAND RIGHTS - FISH/WILDLIFE	SG-P	(163)	(2)	(44)	(12)	(23)	(73)	(9)	(0)	-
1080000	AC PR DPR EL PL SR	3310000	STRUCTURES AND IMPROVE	SG-P	(7)	(0)	(2)	(1)	(1)	(3)	(0)	(0)	-
1080000	AC PR DPR EL PL SR	3310000	STRUCTURES AND IMPROVE	SG-U	(5,963)	(82)	(1,603)	(447)	(821)	(2,676)	(334)	(0)	-
1080000	AC PR DPR EL PL SR	3311000	STRUCTURES AND IMPROVE-PRODUCTION	SG-P	(27,309)	(376)	(7,342)	(2,045)	(3,762)	(12,256)	(1,528)	(0)	-
1080000	AC PR DPR EL PL SR	3311000	STRUCTURES AND IMPROVE-PRODUCTION	SG-U	(3,040)	(42)	(817)	(228)	(419)	(1,365)	(170)	(0)	-
1080000	AC PR DPR EL PL SR	3312000	STRUCTURES AND IMPROVE-FISH/WILDLIFE	SG-P	(34,016)	(468)	(9,145)	(2,547)	(4,686)	(15,267)	(1,903)	(0)	-
1080000	AC PR DPR EL PL SR	3312000	STRUCTURES AND IMPROVE-FISH/WILDLIFE	SG-U	(290)	(4)	(78)	(22)	(40)	(130)	(16)	(0)	-
1080000	AC PR DPR EL PL SR	3313000	STRUCTURES AND IMPROVE-RECREATION	SG-P	(7,581)	(104)	(2,038)	(568)	(1,044)	(3,402)	(424)	(0)	-
1080000	AC PR DPR EL PL SR	3313000	STRUCTURES AND IMPROVE-RECREATION	SG-U	(1,201)	(17)	(323)	(90)	(165)	(539)	(67)	(0)	-
1080000	AC PR DPR EL PL SR	3320000	"RESERVOIRS, DAMS & WATERWAYS"	SG-P	(1,899)	(26)	(511)	(142)	(262)	(852)	(106)	(0)	-
1080000	AC PR DPR EL PL SR	3320000	"RESERVOIRS, DAMS & WATERWAYS"	SG-U	(20,016)	(276)	(5,381)	(1,499)	(2,757)	(8,983)	(1,120)	(0)	-
1080000	AC PR DPR EL PL SR	3321000	"RESERVOIRS, DAMS, & WTRWYS-PRODUCTION"	SG-P	(185,327)	(2,552)	(49,824)	(13,878)	(25,531)	(83,175)	(10,368)	(0)	-
1080000	AC PR DPR EL PL SR	3321000	"RESERVOIRS, DAMS, & WTRWYS-PRODUCTION"	SG-U	(42,022)	(579)	(11,297)	(3,147)	(5,789)	(18,860)	(2,351)	(0)	-
1080000	AC PR DPR EL PL SR	3322000	"RESERVOIRS, DAMS, & WTRWYS-FISH/WILDLIF	SG-P	(6,473)	(89)	(1,740)	(485)	(892)	(2,905)	(362)	(0)	-
1080000	AC PR DPR EL PL SR	3322000	"RESERVOIRS, DAMS, & WTRWYS-FISH/WILDLIF	SG-U	(319)	(4)	(86)	(24)	(44)	(143)	(18)	(0)	-
1080000	AC PR DPR EL PL SR	3323000	"RESERVOIRS, DAMS, & WTRWYS-RECREATION"	SG-P	(83)	(1)	(22)	(6)	(11)	(37)	(5)	(0)	-
1080000	AC PR DPR EL PL SR	3323000	"RESERVOIRS, DAMS, & WTRWYS-RECREATION"	SG-U	(49)	(1)	(13)	(4)	(7)	(22)	(3)	(0)	-
1080000	AC PR DPR EL PL SR	3330000	"WATER WHEELS, TURB & GENERATORS"	SG-P	(38,659)	(532)	(10,393)	(2,895)	(5,326)	(17,350)	(2,163)	(0)	-
1080000	AC PR DPR EL PL SR	3330000	"WATER WHEELS, TURB & GENERATORS"	SG-U	(25,274)	(348)	(6,795)	(1,893)	(3,482)	(11,343)	(1,414)	(0)	-
1080000	AC PR DPR EL PL SR	3340000	ACCESSORY ELECTRIC EQUIPMENT	SG-P	(23,132)	(318)	(6,219)	(1,732)	(3,187)	(10,382)	(1,294)	(0)	-
1080000	AC PR DPR EL PL SR	3340000	ACCESSORY ELECTRIC EQUIPMENT	SG-U	(8,344)	(115)	(2,243)	(625)	(1,149)	(3,745)	(467)	(0)	-
1080000	AC PR DPR EL PL SR	3347000	ACCESSORY ELECT EQUIP - SUPV & ALARM	SG-P	(1,402)	(19)	(377)	(105)	(193)	(629)	(78)	(0)	-
1080000	AC PR DPR EL PL SR	3347000	ACCESSORY ELECT EQUIP - SUPV & ALARM	SG-U	(22)	(0)	(6)	(2)	(3)	(10)	(1)	(0)	-
1080000	AC PR DPR EL PL SR	3350000	MISC POWER PLANT EQUIP	SG-U	(133)	(2)	(36)	(10)	(18)	(60)	(7)	(0)	-
1080000	AC PR DPR EL PL SR	3351000	MISC POWER PLANT EQUIP - PRODUCTION	SG-P	(1,330)	(18)	(357)	(100)	(183)	(597)	(74)	(0)	-
1080000	AC PR DPR EL PL SR	3360000	"ROADS, RAILROADS & BRIDGES"	SG-P	(8,640)	(119)	(2,323)	(647)	(1,190)	(3,878)	(483)	(0)	-
1080000	AC PR DPR EL PL SR	3360000	"ROADS, RAILROADS & BRIDGES"	SG-U	(1,478)	(20)	(397)	(111)	(204)	(663)	(83)	(0)	-
1080000	AC PR DPR EL PL SR	3402000	LAND RIGHTS	SG	682	9	183	51	94	306	38	0	-
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	OR	(0)	-	(0)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3410000	STRUCTURES & IMPROVEMENTS	SG	(39,606)	(545)	(10,648)	(2,966)	(5,456)	(17,775)	(2,216)	(0)	-
1080000	AC PR DPR EL PL SR	3410000	STRUCTURES & IMPROVEMENTS	UT	(7)	-	-	-	-	(7)	-	-	-
1080000	AC PR DPR EL PL SR	3420000	"FUEL HOLDERS,PRODUCERS, ACCES"	SG	(5,150)	(71)	(1,384)	(386)	(709)	(2,311)	(288)	(0)	-
1080000	AC PR DPR EL PL SR	3430000	PRIME MOVERS	SG	(293,431)	(4,040)	(78,886)	(21,973)	(40,424)	(131,693)	(16,415)	(0)	-
1080000	AC PR DPR EL PL SR	3440000	GENERATORS	SG	(119,452)	(1,645)	(32,114)	(8,945)	(16,456)	(53,610)	(6,682)	(0)	-
1080000	AC PR DPR EL PL SR	3440000	GENERATORS	UT	(29)	-	-	-	-	(29)	-	-	-

PACIFICORP

Depreciation Reserve (Actuals)
Year End: 06/2023
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	3450000	ACCESSORY ELECTRIC EQUIPMENT	SG	(41,394)	(570)	(11,129)	(3,100)	(5,703)	(18,578)	(2,316)	(0)	-
1080000	AC PR DPR EL PL SR	3450000	ACCESSORY ELECTRIC EQUIPMENT	UT	(8)	-	-	-	-	(8)	-	-	-
1080000	AC PR DPR EL PL SR	3460000	MISCELLANEOUS PWR PLANT EQUIP	SG	(3,381)	(47)	(909)	(253)	(466)	(1,517)	(189)	(0)	-
1080000	AC PR DPR EL PL SR	3502000	LAND RIGHTS	SG	(51,475)	(709)	(13,839)	(3,855)	(7,091)	(23,102)	(2,880)	(0)	-
1080000	AC PR DPR EL PL SR	3520000	STRUCTURES & IMPROVEMENTS	SG	(66,230)	(912)	(17,805)	(4,959)	(9,124)	(29,724)	(3,705)	(0)	-
1080000	AC PR DPR EL PL SR	3530000	STATION EQUIPMENT	SG	(577,734)	(7,955)	(155,319)	(43,262)	(79,590)	(259,289)	(32,320)	(0)	-
1080000	AC PR DPR EL PL SR	3534000	STATION EQUIPMENT, STEP-UP TRANSFORMERS	SG	(46,321)	(638)	(12,453)	(3,469)	(6,381)	(20,789)	(2,591)	(0)	-
1080000	AC PR DPR EL PL SR	3537000	STATION EQUIPMENT-SUPERVISORY & ALARM	SG	(6,693)	(92)	(1,799)	(501)	(922)	(3,004)	(374)	(0)	-
1080000	AC PR DPR EL PL SR	3540000	TOWERS AND FIXTURES	SG	(420,731)	(5,793)	(113,110)	(31,505)	(57,961)	(188,825)	(23,537)	(0)	-
1080000	AC PR DPR EL PL SR	3550000	POLES AND FIXTURES	SG	(457,660)	(6,301)	(123,038)	(34,271)	(63,048)	(205,399)	(25,603)	(0)	-
1080000	AC PR DPR EL PL SR	3560000	OVERHEAD CONDUCTORS & DEVICES	SG	(561,224)	(7,727)	(150,880)	(42,026)	(77,315)	(251,879)	(31,396)	(0)	-
1080000	AC PR DPR EL PL SR	3570000	UNDERGROUND CONDUIT	SG	(1,436)	(20)	(386)	(108)	(198)	(645)	(80)	(0)	-
1080000	AC PR DPR EL PL SR	3580000	UNDERGROUND CONDUCTORS & DEVICES	SG	(3,505)	(48)	(942)	(262)	(483)	(1,573)	(196)	(0)	-
1080000	AC PR DPR EL PL SR	3590000	ROADS AND TRAILS	SG	(5,369)	(74)	(1,443)	(402)	(740)	(2,410)	(300)	(0)	-
1080000	AC PR DPR EL PL SR	3602000	LAND RIGHTS	CA	(770)	(770)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3602000	LAND RIGHTS	IDU	(549)	-	-	-	-	-	(549)	-	-
1080000	AC PR DPR EL PL SR	3602000	LAND RIGHTS	OR	(2,501)	-	(2,501)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3602000	LAND RIGHTS	UT	(3,424)	-	-	-	-	(3,424)	-	-	-
1080000	AC PR DPR EL PL SR	3602000	LAND RIGHTS	WA	(218)	-	-	(218)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3602000	LAND RIGHTS	WYP	(1,654)	-	-	-	(1,654)	-	-	-	-
1080000	AC PR DPR EL PL SR	3602000	LAND RIGHTS	WYU	(1,313)	-	-	-	(1,313)	-	-	-	-
1080000	AC PR DPR EL PL SR	3610000	STRUCTURES & IMPROVEMENTS	CA	(1,736)	(1,736)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3610000	STRUCTURES & IMPROVEMENTS	IDU	(984)	-	-	-	-	-	(984)	-	-
1080000	AC PR DPR EL PL SR	3610000	STRUCTURES & IMPROVEMENTS	OR	(9,863)	-	(9,863)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3610000	STRUCTURES & IMPROVEMENTS	UT	(16,881)	-	-	-	-	(16,881)	-	-	-
1080000	AC PR DPR EL PL SR	3610000	STRUCTURES & IMPROVEMENTS	WA	(1,636)	-	-	(1,636)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3610000	STRUCTURES & IMPROVEMENTS	WYP	(4,820)	-	-	-	(4,820)	-	-	-	-
1080000	AC PR DPR EL PL SR	3610000	STRUCTURES & IMPROVEMENTS	WYU	(988)	-	-	-	(988)	-	-	-	-
1080000	AC PR DPR EL PL SR	3620000	STATION EQUIPMENT	CA	(10,942)	(10,942)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3620000	STATION EQUIPMENT	IDU	(12,907)	-	-	-	-	-	(12,907)	-	-
1080000	AC PR DPR EL PL SR	3620000	STATION EQUIPMENT	OR	(105,297)	-	(105,297)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3620000	STATION EQUIPMENT	UT	(163,919)	-	-	-	-	(163,919)	-	-	-
1080000	AC PR DPR EL PL SR	3620000	STATION EQUIPMENT	WA	(29,344)	-	-	(29,344)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3620000	STATION EQUIPMENT	WYP	(46,800)	-	-	-	(46,800)	-	-	-	-
1080000	AC PR DPR EL PL SR	3620000	STATION EQUIPMENT	WYU	(4,630)	-	-	-	(4,630)	-	-	-	-
1080000	AC PR DPR EL PL SR	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	CA	(146)	(146)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	IDU	(174)	-	-	-	-	-	(174)	-	-
1080000	AC PR DPR EL PL SR	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	OR	(1,534)	-	(1,534)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	UT	(2,118)	-	-	-	-	(2,118)	-	-	-
1080000	AC PR DPR EL PL SR	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	WA	(503)	-	-	(503)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	WYP	(858)	-	-	-	(858)	-	-	-	-
1080000	AC PR DPR EL PL SR	3627000	STATION EQUIPMENT-SUPERVISORY & ALARM	WYU	(48)	-	-	-	(48)	-	-	-	-
1080000	AC PR DPR EL PL SR	3640000	"POLES, TOWERS AND FIXTURES"	CA	(43,857)	(43,857)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3640000	"POLES, TOWERS AND FIXTURES"	IDU	(51,518)	-	-	-	-	-	(51,518)	-	-
1080000	AC PR DPR EL PL SR	3640000	"POLES, TOWERS AND FIXTURES"	OR	(269,539)	-	(269,539)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3640000	"POLES, TOWERS AND FIXTURES"	UT	(177,196)	-	-	-	-	(177,196)	-	-	-
1080000	AC PR DPR EL PL SR	3640000	"POLES, TOWERS AND FIXTURES"	WA	(80,717)	-	-	(80,717)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3640000	"POLES, TOWERS AND FIXTURES"	WYP	(78,220)	-	-	-	(78,220)	-	-	-	-
1080000	AC PR DPR EL PL SR	3640000	"POLES, TOWERS AND FIXTURES"	WYU	(17,087)	-	-	-	(17,087)	-	-	-	-
1080000	AC PR DPR EL PL SR	3650000	OVERHEAD CONDUCTORS & DEVICES	CA	(22,029)	(22,029)	-	-	-	-	-	-	-

PACIFICORP

Depreciation Reserve (Actuals)
Year End: 06/2023
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	3650000	OVERHEAD CONDUCTORS & DEVICES	IDU	(17,384)	-	-	-	-	-	(17,384)	-	-
1080000	AC PR DPR EL PL SR	3650000	OVERHEAD CONDUCTORS & DEVICES	OR	(143,461)	-	(143,461)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3650000	OVERHEAD CONDUCTORS & DEVICES	UT	(89,754)	-	-	-	-	(89,754)	-	-	-
1080000	AC PR DPR EL PL SR	3650000	OVERHEAD CONDUCTORS & DEVICES	WA	(39,607)	-	-	(39,607)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3650000	OVERHEAD CONDUCTORS & DEVICES	WYP	(46,305)	-	-	-	(46,305)	-	-	-	-
1080000	AC PR DPR EL PL SR	3650000	OVERHEAD CONDUCTORS & DEVICES	WYU	(6,215)	-	-	-	(6,215)	-	-	-	-
1080000	AC PR DPR EL PL SR	3660000	UNDERGROUND CONDUIT	CA	(13,047)	(13,047)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3660000	UNDERGROUND CONDUIT	IDU	(4,994)	-	-	-	-	-	(4,994)	-	-
1080000	AC PR DPR EL PL SR	3660000	UNDERGROUND CONDUIT	OR	(51,732)	-	(51,732)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3660000	UNDERGROUND CONDUIT	UT	(93,815)	-	-	-	-	(93,815)	-	-	-
1080000	AC PR DPR EL PL SR	3660000	UNDERGROUND CONDUIT	WA	(12,011)	-	-	(12,011)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3660000	UNDERGROUND CONDUIT	WYP	(12,533)	-	-	-	(12,533)	-	-	-	-
1080000	AC PR DPR EL PL SR	3660000	UNDERGROUND CONDUIT	WYU	(3,279)	-	-	-	(3,279)	-	-	-	-
1080000	AC PR DPR EL PL SR	3670000	UNDERGROUND CONDUCTORS & DEVICES	CA	(13,580)	(13,580)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3670000	UNDERGROUND CONDUCTORS & DEVICES	IDU	(13,757)	-	-	-	-	-	(13,757)	-	-
1080000	AC PR DPR EL PL SR	3670000	UNDERGROUND CONDUCTORS & DEVICES	OR	(102,483)	-	(102,483)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3670000	UNDERGROUND CONDUCTORS & DEVICES	UT	(219,614)	-	-	-	-	(219,614)	-	-	-
1080000	AC PR DPR EL PL SR	3670000	UNDERGROUND CONDUCTORS & DEVICES	WA	(14,902)	-	-	(14,902)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3670000	UNDERGROUND CONDUCTORS & DEVICES	WYP	(27,175)	-	-	-	(27,175)	-	-	-	-
1080000	AC PR DPR EL PL SR	3670000	UNDERGROUND CONDUCTORS & DEVICES	WYU	(14,823)	-	-	-	(14,823)	-	-	-	-
1080000	AC PR DPR EL PL SR	3680000	LINE TRANSFORMERS	CA	(30,178)	(30,178)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3680000	LINE TRANSFORMERS	IDU	(35,608)	-	-	-	-	-	(35,608)	-	-
1080000	AC PR DPR EL PL SR	3680000	LINE TRANSFORMERS	OR	(262,972)	-	(262,972)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3680000	LINE TRANSFORMERS	UT	(179,482)	-	-	-	-	(179,482)	-	-	-
1080000	AC PR DPR EL PL SR	3680000	LINE TRANSFORMERS	WA	(68,351)	-	-	(68,351)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3680000	LINE TRANSFORMERS	WYP	(51,909)	-	-	-	(51,909)	-	-	-	-
1080000	AC PR DPR EL PL SR	3680000	LINE TRANSFORMERS	WYU	(8,167)	-	-	-	(8,167)	-	-	-	-
1080000	AC PR DPR EL PL SR	3691000	SERVICES - OVERHEAD	CA	(4,297)	(4,297)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3691000	SERVICES - OVERHEAD	IDU	(5,109)	-	-	-	-	-	(5,109)	-	-
1080000	AC PR DPR EL PL SR	3691000	SERVICES - OVERHEAD	OR	(49,204)	-	(49,204)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3691000	SERVICES - OVERHEAD	UT	(43,247)	-	-	-	-	(43,247)	-	-	-
1080000	AC PR DPR EL PL SR	3691000	SERVICES - OVERHEAD	WA	(10,393)	-	-	(10,393)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3691000	SERVICES - OVERHEAD	WYP	(8,003)	-	-	-	(8,003)	-	-	-	-
1080000	AC PR DPR EL PL SR	3691000	SERVICES - OVERHEAD	WYU	(1,348)	-	-	-	(1,348)	-	-	-	-
1080000	AC PR DPR EL PL SR	3692000	SERVICES - UNDERGROUND	CA	(9,248)	(9,248)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3692000	SERVICES - UNDERGROUND	IDU	(15,390)	-	-	-	-	-	(15,390)	-	-
1080000	AC PR DPR EL PL SR	3692000	SERVICES - UNDERGROUND	OR	(107,657)	-	(107,657)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3692000	SERVICES - UNDERGROUND	UT	(87,039)	-	-	-	-	(87,039)	-	-	-
1080000	AC PR DPR EL PL SR	3692000	SERVICES - UNDERGROUND	WA	(25,524)	-	-	(25,524)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3692000	SERVICES - UNDERGROUND	WYP	(22,571)	-	-	-	(22,571)	-	-	-	-
1080000	AC PR DPR EL PL SR	3692000	SERVICES - UNDERGROUND	WYU	(6,603)	-	-	-	(6,603)	-	-	-	-
1080000	AC PR DPR EL PL SR	3700000	METERS	CA	(2,446)	(2,446)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3700000	METERS	IDU	(2,583)	-	-	-	-	-	(2,583)	-	-
1080000	AC PR DPR EL PL SR	3700000	METERS	OR	(32,685)	-	(32,685)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3700000	METERS	UT	(54,334)	-	-	-	-	(54,334)	-	-	-
1080000	AC PR DPR EL PL SR	3700000	METERS	WA	(9,235)	-	-	(9,235)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3700000	METERS	WYP	(9,082)	-	-	-	(9,082)	-	-	-	-
1080000	AC PR DPR EL PL SR	3700000	METERS	WYU	(1,825)	-	-	-	(1,825)	-	-	-	-
1080000	AC PR DPR EL PL SR	3710000	INSTALL ON CUSTOMERS PREMISES	CA	(246)	(246)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3710000	INSTALL ON CUSTOMERS PREMISES	IDU	(127)	-	-	-	-	-	(127)	-	-

PACIFICORP

Depreciation Reserve (Actuals)
Year End: 06/2023
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	OR	(2,124)	-	(2,124)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3710000	INSTALL ON CUSTOMERS PREMISES	UT	(3,344)	-	-	-	-	(3,344)	-	-	-
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	(841)	-	-	-	(841)	-	-	-	-
1080000	AC PR DPR EL PL SR	3710000	INSTALL ON CUSTOMERS PREMISES	WYU	(143)	-	-	-	(143)	-	-	-	-
1080000	AC PR DPR EL PL SR	3730000	STREET LIGHTING & SIGNAL SYSTEMS	CA	(391)	(391)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3730000	STREET LIGHTING & SIGNAL SYSTEMS	IDU	(473)	-	-	-	-	-	(473)	-	-
1080000	AC PR DPR EL PL SR	3730000	STREET LIGHTING & SIGNAL SYSTEMS	OR	(12,324)	-	(12,324)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3730000	STREET LIGHTING & SIGNAL SYSTEMS	UT	(13,325)	-	-	-	-	(13,325)	-	-	-
1080000	AC PR DPR EL PL SR	3730000	STREET LIGHTING & SIGNAL SYSTEMS	WA	(1,628)	-	-	(1,628)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3730000	STREET LIGHTING & SIGNAL SYSTEMS	WYP	(4,170)	-	-	-	(4,170)	-	-	-	-
1080000	AC PR DPR EL PL SR	3730000	STREET LIGHTING & SIGNAL SYSTEMS	WYU	(1,272)	-	-	-	(1,272)	-	-	-	-
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	(9)	(0)	(3)	(1)	(1)	(4)	(1)	(0)	-
1080000	AC PR DPR EL PL SR	3892000	LAND RIGHTS	UT	(25)	-	-	-	-	(25)	-	-	-
1080000	AC PR DPR EL PL SR	3892000	LAND RIGHTS	WYP	(12)	-	-	-	(12)	-	-	-	-
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	(981)	(981)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3900000	STRUCTURES AND IMPROVEMENTS	CN	(2,839)	(64)	(872)	(190)	(202)	(1,391)	(120)	-	-
1080000	AC PR DPR EL PL SR	3900000	STRUCTURES AND IMPROVEMENTS	IDU	(5,548)	-	-	-	-	-	(5,548)	-	-
1080000	AC PR DPR EL PL SR	3900000	STRUCTURES AND IMPROVEMENTS	OR	(11,503)	-	(11,503)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3900000	STRUCTURES AND IMPROVEMENTS	SE	(277)	(4)	(73)	(19)	(41)	(124)	(17)	(0)	-
1080000	AC PR DPR EL PL SR	3900000	STRUCTURES AND IMPROVEMENTS	SG	(3,193)	(44)	(858)	(239)	(440)	(1,433)	(179)	(0)	-
1080000	AC PR DPR EL PL SR	3900000	STRUCTURES AND IMPROVEMENTS	SO	(34,773)	(912)	(9,537)	(2,544)	(4,422)	(15,462)	(1,896)	(0)	-
1080000	AC PR DPR EL PL SR	3900000	STRUCTURES AND IMPROVEMENTS	UT	(15,226)	-	-	-	-	(15,226)	-	-	-
1080000	AC PR DPR EL PL SR	3900000	STRUCTURES AND IMPROVEMENTS	WA	(8,208)	-	-	(8,208)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3900000	STRUCTURES AND IMPROVEMENTS	WYP	(2,007)	-	-	-	(2,007)	-	-	-	-
1080000	AC PR DPR EL PL SR	3900000	STRUCTURES AND IMPROVEMENTS	WYU	(1,506)	-	-	-	(1,506)	-	-	-	-
1080000	AC PR DPR EL PL SR	3910000	OFFICE FURNITURE	CA	(103)	(103)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3910000	OFFICE FURNITURE	CN	(746)	(17)	(229)	(50)	(53)	(366)	(32)	-	-
1080000	AC PR DPR EL PL SR	3910000	OFFICE FURNITURE	IDU	(33)	-	-	-	-	-	(33)	-	-
1080000	AC PR DPR EL PL SR	3910000	OFFICE FURNITURE	OR	(1,009)	-	(1,009)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3910000	OFFICE FURNITURE	SE	(3)	(0)	(1)	(0)	(0)	(1)	(0)	(0)	-
1080000	AC PR DPR EL PL SR	3910000	OFFICE FURNITURE	SG	(947)	(13)	(255)	(71)	(130)	(425)	(53)	(0)	-
1080000	AC PR DPR EL PL SR	3910000	OFFICE FURNITURE	SO	(6,653)	(175)	(1,825)	(487)	(846)	(2,958)	(363)	(0)	-
1080000	AC PR DPR EL PL SR	3910000	OFFICE FURNITURE	UT	(435)	-	-	-	-	(435)	-	-	-
1080000	AC PR DPR EL PL SR	3910000	OFFICE FURNITURE	WA	(42)	-	-	(42)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3910000	OFFICE FURNITURE	WYP	(308)	-	-	-	(308)	-	-	-	-
1080000	AC PR DPR EL PL SR	3910000	OFFICE FURNITURE	WYU	(20)	-	-	-	(20)	-	-	-	-
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	(794)	(18)	(244)	(53)	(56)	(389)	(34)	-	-
1080000	AC PR DPR EL PL SR	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	IDU	(207)	-	-	-	-	-	(207)	-	-
1080000	AC PR DPR EL PL SR	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	OR	(523)	-	(523)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	SE	(15)	(0)	(4)	(1)	(2)	(7)	(1)	(0)	-
1080000	AC PR DPR EL PL SR	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	SG	(1,586)	(22)	(427)	(119)	(219)	(712)	(89)	(0)	-
1080000	AC PR DPR EL PL SR	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	SO	(28,265)	(742)	(7,752)	(2,068)	(3,595)	(12,568)	(1,541)	(0)	-
1080000	AC PR DPR EL PL SR	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	UT	(499)	-	-	-	-	(499)	-	-	-
1080000	AC PR DPR EL PL SR	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	WA	(156)	-	-	(156)	-	-	-	-	-

PACIFICORP

Depreciation Reserve (Actuals)
Year End: 06/2023
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	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	WYP	(672)	-	-	-	(672)	-	-	-	-
1080000	AC PR DPR EL PL SR	3912000	COMPUTER EQUIPMENT - PERSONAL COMPUTERS	WYU	(42)	-	-	-	(42)	-	-	-	-
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	(23)	(0)	(6)	(2)	(3)	(10)	(1)	(0)	-
1080000	AC PR DPR EL PL SR	3913000	OFFICE EQUIPMENT	SO	(136)	(4)	(37)	(10)	(17)	(60)	(7)	(0)	-
1080000	AC PR DPR EL PL SR	3913000	OFFICE EQUIPMENT	UT	(7)	-	-	-	-	(7)	-	-	-
1080000	AC PR DPR EL PL SR	3913000	OFFICE EQUIPMENT	WYU	(6)	-	-	-	(6)	-	-	-	-
1080000	AC PR DPR EL PL SR	3920100	1/4 TON MINI-PICKUPS AND VANS	CA	(38)	(38)	-	-	-	-	-	-	-
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	(972)	-	(972)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3920100	1/4 TON MINI-PICKUPS AND VANS	SE	(21)	(0)	(6)	(1)	(3)	(9)	(1)	(0)	-
1080000	AC PR DPR EL PL SR	3920100	1/4 TON MINI-PICKUPS AND VANS	SG	(378)	(5)	(101)	(28)	(52)	(169)	(21)	(0)	-
1080000	AC PR DPR EL PL SR	3920100	1/4 TON MINI-PICKUPS AND VANS	SO	(390)	(10)	(107)	(29)	(50)	(173)	(21)	(0)	-
1080000	AC PR DPR EL PL SR	3920100	1/4 TON MINI-PICKUPS AND VANS	UT	(1,865)	-	-	-	-	(1,865)	-	-	-
1080000	AC PR DPR EL PL SR	3920100	1/4 TON MINI-PICKUPS AND VANS	WA	(138)	-	-	(138)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3920100	1/4 TON MINI-PICKUPS AND VANS	WYP	(363)	-	-	-	(363)	-	-	-	-
1080000	AC PR DPR EL PL SR	3920200	MID AND FULL SIZE AUTOMOBILES	OR	(99)	-	(99)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3920200	MID AND FULL SIZE AUTOMOBILES	SO	(121)	(3)	(33)	(9)	(15)	(54)	(7)	(0)	-
1080000	AC PR DPR EL PL SR	3920200	MID AND FULL SIZE AUTOMOBILES	UT	(283)	-	-	-	-	(283)	-	-	-
1080000	AC PR DPR EL PL SR	3920200	MID AND FULL SIZE AUTOMOBILES	WYP	(17)	-	-	-	(17)	-	-	-	-
1080000	AC PR DPR EL PL SR	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	CA	(266)	(266)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	IDU	(1,069)	-	-	-	-	-	(1,069)	-	-
1080000	AC PR DPR EL PL SR	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	OR	(3,361)	-	(3,361)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	SE	(57)	(1)	(15)	(4)	(8)	(25)	(3)	(0)	-
1080000	AC PR DPR EL PL SR	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	SG	(5,441)	(75)	(1,463)	(407)	(750)	(2,442)	(304)	(0)	-
1080000	AC PR DPR EL PL SR	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	SO	(761)	(20)	(209)	(56)	(97)	(338)	(41)	(0)	-
1080000	AC PR DPR EL PL SR	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	UT	(5,787)	-	-	-	-	(5,787)	-	-	-
1080000	AC PR DPR EL PL SR	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	WA	(1,108)	-	-	(1,108)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	WYP	(1,087)	-	-	-	(1,087)	-	-	-	-
1080000	AC PR DPR EL PL SR	3920400	"1/2 & 3/4 TON PICKUPS, VANS, SERV TRUCK	WYU	(296)	-	-	-	(296)	-	-	-	-
1080000	AC PR DPR EL PL SR	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	CA	(485)	(485)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	IDU	(1,427)	-	-	-	-	-	(1,427)	-	-
1080000	AC PR DPR EL PL SR	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	OR	(9,466)	-	(9,466)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	SE	(178)	(2)	(47)	(12)	(26)	(79)	(11)	(0)	-
1080000	AC PR DPR EL PL SR	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	SG	(4,242)	(58)	(1,140)	(318)	(584)	(1,904)	(237)	(0)	-
1080000	AC PR DPR EL PL SR	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	SO	(251)	(7)	(69)	(18)	(32)	(112)	(14)	(0)	-
1080000	AC PR DPR EL PL SR	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	UT	(12,062)	-	-	-	-	(12,062)	-	-	-
1080000	AC PR DPR EL PL SR	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	WA	(2,011)	-	-	(2,011)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	WYP	(2,305)	-	-	-	(2,305)	-	-	-	-
1080000	AC PR DPR EL PL SR	3920500	"1 TON AND ABOVE, TWO-AXLE TRUCKS"	WYU	(537)	-	-	-	(537)	-	-	-	-
1080000	AC PR DPR EL PL SR	3920600	DUMP TRUCKS	OR	(150)	-	(150)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3920600	DUMP TRUCKS	SE	(4)	(0)	(1)	(0)	(1)	(2)	(0)	(0)	-
1080000	AC PR DPR EL PL SR	3920600	DUMP TRUCKS	SG	(2,653)	(37)	(713)	(199)	(366)	(1,191)	(148)	(0)	-
1080000	AC PR DPR EL PL SR	3920600	DUMP TRUCKS	UT	(70)	-	-	-	-	(70)	-	-	-
1080000	AC PR DPR EL PL SR	3920600	DUMP TRUCKS	WA	(8)	-	-	(8)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3920900	TRAILERS	CA	(256)	(256)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3920900	TRAILERS	IDU	(520)	-	-	-	-	-	(520)	-	-
1080000	AC PR DPR EL PL SR	3920900	TRAILERS	OR	(1,879)	-	(1,879)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3920900	TRAILERS	SE	(35)	(0)	(9)	(2)	(5)	(15)	(2)	(0)	-

PACIFICORP

Depreciation Reserve (Actuals)
Year End: 06/2023
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	3920900	TRAILERS	SG	(886)	(12)	(238)	(66)	(122)	(398)	(50)	(0)	-
1080000	AC PR DPR EL PL SR	3920900	TRAILERS	SO	(397)	(10)	(109)	(29)	(50)	(176)	(22)	(0)	-
1080000	AC PR DPR EL PL SR	3920900	TRAILERS	UT	(4,226)	-	-	-	-	(4,226)	-	-	-
1080000	AC PR DPR EL PL SR	3920900	TRAILERS	WA	(402)	-	-	(402)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3920900	TRAILERS	WYP	(1,574)	-	-	-	(1,574)	-	-	-	-
1080000	AC PR DPR EL PL SR	3920900	TRAILERS	WYU	(358)	-	-	-	(358)	-	-	-	-
1080000	AC PR DPR EL PL SR	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	CA	(99)	(99)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	IDU	(55)	-	-	-	-	-	(55)	-	-
1080000	AC PR DPR EL PL SR	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	OR	(344)	-	(344)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	SE	(5)	(0)	(1)	(0)	(1)	(2)	(0)	(0)	-
1080000	AC PR DPR EL PL SR	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	SG	(625)	(9)	(168)	(47)	(86)	(280)	(35)	(0)	-
1080000	AC PR DPR EL PL SR	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	SO	(38)	(1)	(10)	(3)	(5)	(17)	(2)	(0)	-
1080000	AC PR DPR EL PL SR	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	UT	(234)	-	-	-	-	(234)	-	-	-
1080000	AC PR DPR EL PL SR	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	WA	(73)	-	-	(73)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	WYP	(176)	-	-	-	(176)	-	-	-	-
1080000	AC PR DPR EL PL SR	3921400	"SNOWMOBILES, MOTORCYCLES (4-WHEELED ATV	WYU	(35)	-	-	-	(35)	-	-	-	-
1080000	AC PR DPR EL PL SR	3921900	OVER-THE-ROAD SEMI-TRACTORS	OR	(261)	-	(261)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3921900	OVER-THE-ROAD SEMI-TRACTORS	SG	(432)	(6)	(116)	(32)	(60)	(194)	(24)	(0)	-
1080000	AC PR DPR EL PL SR	3921900	OVER-THE-ROAD SEMI-TRACTORS	SO	(163)	(4)	(45)	(12)	(21)	(73)	(9)	(0)	-
1080000	AC PR DPR EL PL SR	3921900	OVER-THE-ROAD SEMI-TRACTORS	UT	(940)	-	-	-	-	(940)	-	-	-
1080000	AC PR DPR EL PL SR	3921900	OVER-THE-ROAD SEMI-TRACTORS	WA	(160)	-	-	(160)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3921900	OVER-THE-ROAD SEMI-TRACTORS	WYP	(65)	-	-	-	(65)	-	-	-	-
1080000	AC PR DPR EL PL SR	3923000	TRANSPORTATION EQUIPMENT	SO	(1,458)	(38)	(400)	(107)	(185)	(648)	(79)	(0)	-
1080000	AC PR DPR EL PL SR	3930000	STORES EQUIPMENT	CA	(50)	(50)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3930000	STORES EQUIPMENT	IDU	(333)	-	-	-	-	-	(333)	-	-
1080000	AC PR DPR EL PL SR	3930000	STORES EQUIPMENT	OR	(1,317)	-	(1,317)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3930000	STORES EQUIPMENT	SG	(3,115)	(43)	(838)	(233)	(429)	(1,398)	(174)	(0)	-
1080000	AC PR DPR EL PL SR	3930000	STORES EQUIPMENT	SO	(122)	(3)	(34)	(9)	(16)	(54)	(7)	(0)	-
1080000	AC PR DPR EL PL SR	3930000	STORES EQUIPMENT	UT	(1,852)	-	-	-	-	(1,852)	-	-	-
1080000	AC PR DPR EL PL SR	3930000	STORES EQUIPMENT	WA	(400)	-	-	(400)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3930000	STORES EQUIPMENT	WYP	(589)	-	-	-	(589)	-	-	-	-
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	(429)	(429)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3940000	"TLS, SHOP, GAR EQUIPMENT"	IDU	(1,197)	-	-	-	-	-	(1,197)	-	-
1080000	AC PR DPR EL PL SR	3940000	"TLS, SHOP, GAR EQUIPMENT"	OR	(5,496)	-	(5,496)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3940000	"TLS, SHOP, GAR EQUIPMENT"	SE	(84)	(1)	(22)	(6)	(12)	(37)	(5)	(0)	-
1080000	AC PR DPR EL PL SR	3940000	"TLS, SHOP, GAR EQUIPMENT"	SG	(11,514)	(159)	(3,096)	(862)	(1,586)	(5,168)	(644)	(0)	-
1080000	AC PR DPR EL PL SR	3940000	"TLS, SHOP, GAR EQUIPMENT"	SO	(1,252)	(33)	(343)	(92)	(159)	(557)	(68)	(0)	-
1080000	AC PR DPR EL PL SR	3940000	"TLS, SHOP, GAR EQUIPMENT"	UT	(7,754)	-	-	-	-	(7,754)	-	-	-
1080000	AC PR DPR EL PL SR	3940000	"TLS, SHOP, GAR EQUIPMENT"	WA	(1,392)	-	-	(1,392)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3940000	"TLS, SHOP, GAR EQUIPMENT"	WYP	(1,923)	-	-	-	(1,923)	-	-	-	-
1080000	AC PR DPR EL PL SR	3940000	"TLS, SHOP, GAR EQUIPMENT"	WYU	(244)	-	-	-	(244)	-	-	-	-
1080000	AC PR DPR EL PL SR	3950000	LABORATORY EQUIPMENT	CA	(228)	(228)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3950000	LABORATORY EQUIPMENT	IDU	(824)	-	-	-	-	-	(824)	-	-
1080000	AC PR DPR EL PL SR	3950000	LABORATORY EQUIPMENT	OR	(4,887)	-	(4,887)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3950000	LABORATORY EQUIPMENT	SE	(741)	(9)	(195)	(51)	(110)	(331)	(45)	(0)	-
1080000	AC PR DPR EL PL SR	3950000	LABORATORY EQUIPMENT	SG	(3,838)	(53)	(1,032)	(287)	(529)	(1,723)	(215)	(0)	-
1080000	AC PR DPR EL PL SR	3950000	LABORATORY EQUIPMENT	SO	(2,639)	(69)	(724)	(193)	(336)	(1,174)	(144)	(0)	-
1080000	AC PR DPR EL PL SR	3950000	LABORATORY EQUIPMENT	UT	(4,372)	-	-	-	-	(4,372)	-	-	-
1080000	AC PR DPR EL PL SR	3950000	LABORATORY EQUIPMENT	WA	(820)	-	-	(820)	-	-	-	-	-

PACIFICORP

Depreciation Reserve (Actuals)
Year End: 06/2023
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	WYP	(1,488)	-	-	-	(1,488)	-	-	-	-
1080000	AC PR DPR EL PL SR	3950000	LABORATORY EQUIPMENT	WYU	(85)	-	-	-	(85)	-	-	-	-
1080000	AC PR DPR EL PL SR	3960300	AERIAL LIFT PB TRUCKS, 10000#-16000# GVW	CA	(1,205)	(1,205)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3960300	AERIAL LIFT PB TRUCKS, 10000#-16000# GVW	IDU	(2,010)	-	-	-	-	-	(2,010)	-	-
1080000	AC PR DPR EL PL SR	3960300	AERIAL LIFT PB TRUCKS, 10000#-16000# GVW	OR	(10,206)	-	(10,206)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3960300	AERIAL LIFT PB TRUCKS, 10000#-16000# GVW	SG	(260)	(4)	(70)	(19)	(36)	(117)	(15)	(0)	-
1080000	AC PR DPR EL PL SR	3960300	AERIAL LIFT PB TRUCKS, 10000#-16000# GVW	SO	(705)	(18)	(193)	(52)	(90)	(313)	(38)	(0)	-
1080000	AC PR DPR EL PL SR	3960300	AERIAL LIFT PB TRUCKS, 10000#-16000# GVW	UT	(9,605)	-	-	-	-	(9,605)	-	-	-
1080000	AC PR DPR EL PL SR	3960300	AERIAL LIFT PB TRUCKS, 10000#-16000# GVW	WA	(2,248)	-	-	(2,248)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3960300	AERIAL LIFT PB TRUCKS, 10000#-16000# GVW	WYP	(4,038)	-	-	-	(4,038)	-	-	-	-
1080000	AC PR DPR EL PL SR	3960300	AERIAL LIFT PB TRUCKS, 10000#-16000# GVW	WYU	(672)	-	-	-	(672)	-	-	-	-
1080000	AC PR DPR EL PL SR	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	IDU	(165)	-	-	-	-	-	(165)	-	-
1080000	AC PR DPR EL PL SR	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	OR	(619)	-	(619)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	SG	(90)	(1)	(24)	(7)	(12)	(40)	(5)	(0)	-
1080000	AC PR DPR EL PL SR	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	UT	(352)	-	-	-	-	(352)	-	-	-
1080000	AC PR DPR EL PL SR	3960700	TWO-AXLE DIGGER/DERRICK LINE TRUCKS	WYU	(117)	-	-	-	(117)	-	-	-	-
1080000	AC PR DPR EL PL SR	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	CA	(533)	(533)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	IDU	(1,351)	-	-	-	-	-	(1,351)	-	-
1080000	AC PR DPR EL PL SR	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	OR	(6,397)	-	(6,397)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	SG	(701)	(10)	(188)	(52)	(97)	(314)	(39)	(0)	-
1080000	AC PR DPR EL PL SR	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	SO	(762)	(20)	(209)	(56)	(97)	(339)	(42)	(0)	-
1080000	AC PR DPR EL PL SR	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	UT	(6,281)	-	-	-	-	(6,281)	-	-	-
1080000	AC PR DPR EL PL SR	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	WA	(1,850)	-	-	(1,850)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	WYP	(1,933)	-	-	-	(1,933)	-	-	-	-
1080000	AC PR DPR EL PL SR	3960800	"AERIAL LIFT P.B. TRUCKS, ABOVE 16000#GV	WYU	(367)	-	-	-	(367)	-	-	-	-
1080000	AC PR DPR EL PL SR	3961000	CRANES	OR	(355)	-	(355)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3961000	CRANES	SG	(1,485)	(20)	(399)	(111)	(205)	(666)	(83)	(0)	-
1080000	AC PR DPR EL PL SR	3961000	CRANES	UT	(73)	-	-	-	-	(73)	-	-	-
1080000	AC PR DPR EL PL SR	3961000	CRANES	WYP	(39)	-	-	-	(39)	-	-	-	-
1080000	AC PR DPR EL PL SR	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	OR	(514)	-	(514)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	SG	(10,968)	(151)	(2,949)	(821)	(1,511)	(4,923)	(614)	(0)	-
1080000	AC PR DPR EL PL SR	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	SO	(565)	(15)	(155)	(41)	(72)	(251)	(31)	(0)	-
1080000	AC PR DPR EL PL SR	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	UT	(1,019)	-	-	-	-	(1,019)	-	-	-
1080000	AC PR DPR EL PL SR	3961100	HEAVY CONSTRUCTION EQUIP, PRODUCT DIGGER	WYP	(240)	-	-	-	(240)	-	-	-	-
1080000	AC PR DPR EL PL SR	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	CA	(605)	(605)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	IDU	(1,349)	-	-	-	-	-	(1,349)	-	-
1080000	AC PR DPR EL PL SR	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	OR	(5,475)	-	(5,475)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	SG	(208)	(3)	(56)	(16)	(29)	(93)	(12)	(0)	-
1080000	AC PR DPR EL PL SR	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	SO	(432)	(11)	(118)	(32)	(55)	(192)	(24)	(0)	-
1080000	AC PR DPR EL PL SR	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	UT	(7,582)	-	-	-	-	(7,582)	-	-	-
1080000	AC PR DPR EL PL SR	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	WA	(1,278)	-	-	(1,278)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	WYP	(1,516)	-	-	-	(1,516)	-	-	-	-
1080000	AC PR DPR EL PL SR	3961200	THREE-AXLE DIGGER/DERRICK LINE TRUCKS	WYU	(294)	-	-	-	(294)	-	-	-	-
1080000	AC PR DPR EL PL SR	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	CA	(341)	(341)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	IDU	(714)	-	-	-	-	-	(714)	-	-
1080000	AC PR DPR EL PL SR	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	OR	(1,644)	-	(1,644)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	SE	(139)	(2)	(37)	(10)	(21)	(62)	(8)	(0)	-
1080000	AC PR DPR EL PL SR	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	SG	(2,985)	(41)	(802)	(223)	(411)	(1,339)	(167)	(0)	-
1080000	AC PR DPR EL PL SR	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	SO	(237)	(6)	(65)	(17)	(30)	(105)	(13)	(0)	-
1080000	AC PR DPR EL PL SR	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	UT	(3,124)	-	-	-	-	(3,124)	-	-	-

Depreciation Reserve (Actuals)
Year End: 06/2023
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	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	WA	(464)	-	-	(464)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	WYP	(842)	-	-	-	(842)	-	-	-	-
1080000	AC PR DPR EL PL SR	3961300	SNOWCATS, BACKHOES, TRENCHERS, SNOWBLOWR	WYU	(234)	-	-	-	(234)	-	-	-	-
1080000	AC PR DPR EL PL SR	3970000	COMMUNICATION EQUIPMENT	CA	(2,121)	(2,121)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3970000	COMMUNICATION EQUIPMENT	CN	(1,878)	(43)	(577)	(126)	(133)	(920)	(80)	-	-
1080000	AC PR DPR EL PL SR	3970000	COMMUNICATION EQUIPMENT	IDU	(6,345)	-	-	-	-	-	(6,345)	-	-
1080000	AC PR DPR EL PL SR	3970000	COMMUNICATION EQUIPMENT	OR	(23,129)	-	(23,129)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3970000	COMMUNICATION EQUIPMENT	SE	(155)	(2)	(41)	(11)	(23)	(69)	(9)	(0)	-
1080000	AC PR DPR EL PL SR	3970000	COMMUNICATION EQUIPMENT	SG	(85,414)	(1,176)	(22,963)	(6,396)	(11,767)	(38,334)	(4,778)	(0)	-
1080000	AC PR DPR EL PL SR	3970000	COMMUNICATION EQUIPMENT	SO	(41,110)	(1,078)	(11,275)	(3,008)	(5,228)	(18,280)	(2,241)	(0)	-
1080000	AC PR DPR EL PL SR	3970000	COMMUNICATION EQUIPMENT	UT	(29,455)	-	-	-	-	(29,455)	-	-	-
1080000	AC PR DPR EL PL SR	3970000	COMMUNICATION EQUIPMENT	WA	(5,437)	-	-	(5,437)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3970000	COMMUNICATION EQUIPMENT	WYP	(11,284)	-	-	-	(11,284)	-	-	-	-
1080000	AC PR DPR EL PL SR	3970000	COMMUNICATION EQUIPMENT	WYU	(3,029)	-	-	-	(3,029)	-	-	-	-
1080000	AC PR DPR EL PL SR	3972000	MOBILE RADIO EQUIPMENT	CA	(284)	(284)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3972000	MOBILE RADIO EQUIPMENT	IDU	(23)	-	-	-	-	-	(23)	-	-
1080000	AC PR DPR EL PL SR	3972000	MOBILE RADIO EQUIPMENT	OR	(922)	-	(922)	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3972000	MOBILE RADIO EQUIPMENT	SE	(82)	(1)	(22)	(6)	(12)	(37)	(5)	(0)	-
1080000	AC PR DPR EL PL SR	3972000	MOBILE RADIO EQUIPMENT	SG	(3,005)	(41)	(808)	(225)	(414)	(1,349)	(168)	(0)	-
1080000	AC PR DPR EL PL SR	3972000	MOBILE RADIO EQUIPMENT	SO	(69)	(2)	(19)	(5)	(9)	(31)	(4)	(0)	-
1080000	AC PR DPR EL PL SR	3972000	MOBILE RADIO EQUIPMENT	UT	(182)	-	-	-	-	(182)	-	-	-
1080000	AC PR DPR EL PL SR	3972000	MOBILE RADIO EQUIPMENT	WA	(58)	-	-	(58)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3972000	MOBILE RADIO EQUIPMENT	WYP	(75)	-	-	-	(75)	-	-	-	-
1080000	AC PR DPR EL PL SR	3972000	MOBILE RADIO EQUIPMENT	WYU	(8)	-	-	-	(8)	-	-	-	-
1080000	AC PR DPR EL PL SR	3980000	MISCELLANEOUS EQUIPMENT	CA	(34)	(34)	-	-	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3980000	MISCELLANEOUS EQUIPMENT	CN	(47)	(1)	(15)	(3)	(3)	(23)	(2)	-	-
1080000	AC PR DPR EL PL SR	3980000	MISCELLANEOUS EQUIPMENT	IDU	(42)	-	-	-	-	-	(42)	-	-
1080000	AC PR DPR EL PL SR	3980000	MISCELLANEOUS EQUIPMENT	OR	(684)	-	(684)	-	-	-	-	-	-
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	(1,615)	(22)	(434)	(121)	(223)	(725)	(90)	(0)	-
1080000	AC PR DPR EL PL SR	3980000	MISCELLANEOUS EQUIPMENT	SO	(922)	(24)	(253)	(67)	(117)	(410)	(50)	(0)	-
1080000	AC PR DPR EL PL SR	3980000	MISCELLANEOUS EQUIPMENT	UT	(734)	-	-	-	-	(734)	-	-	-
1080000	AC PR DPR EL PL SR	3980000	MISCELLANEOUS EQUIPMENT	WA	(108)	-	-	(108)	-	-	-	-	-
1080000	AC PR DPR EL PL SR	3980000	MISCELLANEOUS EQUIPMENT	WYP	(90)	-	-	-	(90)	-	-	-	-
1080000	AC PR DPR EL PL SR	3980000	MISCELLANEOUS EQUIPMENT	WYU	(14)	-	-	-	(14)	-	-	-	-
1080000 Total					**(10,973,772)**	**(264,154)**	**(3,228,897)**	**(873,033)**	**(1,437,856)**	**(4,572,428)**	**(597,405)**	**(0)**	**-**
1083000	AC PR DPR-REMOVAL	288351	REG LIAB - STEAM DECOMM - ID	IDU	(2,949)	-	-	-	-	-	(2,949)	-	-
1083000	AC PR DPR-REMOVAL	288353	REG LIAB - STEAM DECOMM - UT	UT	(42,634)	-	-	-	-	(42,634)	-	-	-
1083000	AC PR DPR-REMOVAL	288355	REG LIAB - STEAM DECOMM - WY	WYP	(11,338)	-	-	-	(11,338)	-	-	-	-
1083000	AC PR DPR-REMOVAL	288365	Reg Liab - Steam Decomm - WA	WA	(8,924)	-	-	(8,924)	-	-	-	-	-
1083000 Total					**(65,845)**	**-**	**-**	**(8,924)**	**(11,338)**	**(42,634)**	**(2,949)**	**-**	**-**
1085000	AC PR DPR-ACCRUAL	145129	BUILDINGS - ACCUMULATED DEPRECIATION-NON	SO	802	21	220	59	102	356	44	0	-
1085000	AC PR DPR-ACCRUAL	145135	ACCUM DEPR-HYDRO DECOMMISSIONING	SG-P	(4,501)	(62)	(1,210)	(337)	(620)	(2,020)	(252)	(0)	-
1085000	AC PR DPR-ACCRUAL	145135	ACCUM DEPR-HYDRO DECOMMISSIONING	SG-U	(850)	(12)	(229)	(64)	(117)	(381)	(48)	(0)	-
1085000	AC PR DPR-ACCRUAL	145139	PRODUCTION PLANT-ACCUM DEPRECIATION	SG	18,735	258	5,037	1,403	2,581	8,408	1,048	0	-
1085000	AC PR DPR-ACCRUAL	145149	TRANSMISSION PLANT ACCUMULATED DEPR NON-	SG	2,897	40	779	217	399	1,300	162	0	-
1085000	AC PR DPR-ACCRUAL	145169	DISTRIBUTION - ACCUMULATED DEPRECIATION	CA	32	32	-	-	-	-	-	-	-
1085000	AC PR DPR-ACCRUAL	145169	DISTRIBUTION - ACCUMULATED DEPRECIATION	IDU	37	-	-	-	-	-	37	-	-
1085000	AC PR DPR-ACCRUAL	145169	DISTRIBUTION - ACCUMULATED DEPRECIATION	OR	686	-	686	-	-	-	-	-	-
1085000	AC PR DPR-ACCRUAL	145169	DISTRIBUTION - ACCUMULATED DEPRECIATION	UT	870	-	-	-	-	870	-	-	-

Depreciation Reserve (Actuals)
Year End: 06/2023
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
1085000	AC PR DPR-ACCRUAL	145169	DISTRIBUTION - ACCUMULATED DEPRECIATION	WA	303	-	-	303	-	-	-	-	-
1085000	AC PR DPR-ACCRUAL	145169	DISTRIBUTION - ACCUMULATED DEPRECIATION	WYU	212	-	-	-	212	-	-	-	-
1085000 Total					**19,223**	**278**	**5,283**	**1,581**	**2,557**	**8,533**	**992**	**0**	**-**
Grand Total					**(11,020,394)**	**(263,876)**	**(3,223,614)**	**(880,376)**	**(1,446,637)**	**(4,606,529)**	**(599,362)**	**(0)**	**-**

B18.AMORTIZATION RESERVE

PACIFICORP

Amortization Reserve (Actuals)
Year End: 06/2023
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	(1,000)	-	-	-	-	-	(1,000)	-	-
1110000	AC PR AMR EL PT SR	3020000	FRANCHISES AND CONSENTS	SG	(6,150)	(85)	(1,653)	(461)	(847)	(2,760)	(344)	(0)	-
1110000	AC PR AMR EL PT SR	3020000	FRANCHISES AND CONSENTS	SG-P	(45,682)	(629)	(12,281)	(3,421)	(6,293)	(20,502)	(2,556)	(0)	-
1110000	AC PR AMR EL PT SR	3020000	FRANCHISES AND CONSENTS	SG-U	(6,812)	(94)	(1,831)	(510)	(938)	(3,057)	(381)	(0)	-
1110000	AC PR AMR EL PT SR	3031040	INTANGIBLE PLANT	OR	(139)	-	(139)	-	-	-	-	-	-
1110000	AC PR AMR EL PT SR	3031040	INTANGIBLE PLANT	SG	(18,861)	(260)	(5,071)	(1,412)	(2,598)	(8,465)	(1,055)	(0)	-
1110000	AC PR AMR EL PT SR	3031040	INTANGIBLE PLANT	UT	(203)	-	-	-	-	(203)	-	-	-
1110000	AC PR AMR EL PT SR	3031040	INTANGIBLE PLANT	WYP	(290)	-	-	-	(290)	-	-	-	-
1110000	AC PR AMR EL PT SR	3031050	REGIONAL CONST MGMT SYS	SO	(11,209)	(294)	(3,074)	(820)	(1,425)	(4,984)	(611)	(0)	-
1110000	AC PR AMR EL PT SR	3031080	FUEL MGMT SYSTEM	SO	(3,293)	(86)	(903)	(241)	(419)	(1,464)	(180)	(0)	-
1110000	AC PR AMR EL PT SR	3031230	AFPR - AUTOMATED FACILITY POINT RECORDS	SO	(4,410)	(116)	(1,209)	(323)	(561)	(1,961)	(240)	(0)	-
1110000	AC PR AMR EL PT SR	3031680	CADOPS - COMPUTER-ASSISTED DISTRIBUTION	SO	(15,446)	(405)	(4,236)	(1,130)	(1,964)	(6,868)	(842)	(0)	-
1110000	AC PR AMR EL PT SR	3031830	CUSTOMER SERVICE SYSTEM	CN	(138,235)	(3,131)	(42,446)	(9,250)	(9,813)	(67,728)	(5,868)	-	-
1110000	AC PR AMR EL PT SR	3032040	SAP	SO	(169,947)	(4,458)	(46,609)	(12,434)	(21,613)	(75,566)	(9,266)	(0)	-
1110000	AC PR AMR EL PT SR	3032130	NODAL PRICING SOFTWARE	SG	(1,434)	(20)	(386)	(107)	(198)	(644)	(80)	(0)	-
1110000	AC PR AMR EL PT SR	3032140	ESM-IRP	SO	(1,332)	(35)	(365)	(97)	(169)	(592)	(73)	(0)	-
1110000	AC PR AMR EL PT SR	3032150	CELONIS	SO	(2,000)	(52)	(548)	(146)	(254)	(889)	(109)	(0)	-
1110000	AC PR AMR EL PT SR	3032160	ARCOS	SO	(1,137)	(30)	(312)	(83)	(145)	(505)	(62)	(0)	-
1110000	AC PR AMR EL PT SR	3032170	AZURE B2C - IDENTITY MGT	SO	(512)	(13)	(140)	(37)	(65)	(228)	(28)	(0)	-
1110000	AC PR AMR EL PT SR	3032180	IAM - SCHEDULING/TAGGING SYSTEM	SO	(421)	(11)	(115)	(31)	(54)	(187)	(23)	(0)	-
1110000	AC PR AMR EL PT SR	3032190	1110000/3032190	SO	(1,483)	(39)	(407)	(109)	(189)	(659)	(81)	(0)	-
1110000	AC PR AMR EL PT SR	3032200	ITOA	SO	(1,327)	(35)	(364)	(97)	(169)	(590)	(72)	(0)	-
1110000	AC PR AMR EL PT SR	3032210	FACILITY INSPECTION REPORTING SYS	SO	(471)	(12)	(129)	(34)	(60)	(209)	(26)	(0)	-
1110000	AC PR AMR EL PT SR	3032270	ENTERPRISE DATA WAREHOUSE	SO	(5,877)	(154)	(1,612)	(430)	(747)	(2,613)	(320)	(0)	-
1110000	AC PR AMR EL PT SR	3032330	FIELDNET PRO METER READING SYST -HRP REP	SO	(2,908)	(76)	(797)	(213)	(370)	(1,293)	(159)	(0)	-
1110000	AC PR AMR EL PT SR	3032340	FACILITY INSPECTION REPORTING SYSTEM	SO	(2,020)	(53)	(554)	(148)	(257)	(898)	(110)	(0)	-
1110000	AC PR AMR EL PT SR	3032360	2002 GRID NET POWER COST MODELING	SO	(8,999)	(236)	(2,468)	(658)	(1,144)	(4,001)	(491)	(0)	-
1110000	AC PR AMR EL PT SR	3032450	MID OFFICE IMPROVEMENT PROJECT	SO	(10,570)	(277)	(2,899)	(773)	(1,344)	(4,700)	(576)	(0)	-
1110000	AC PR AMR EL PT SR	3032510	OPERATIONS MAPPING SYSTEM	SO	(10,386)	(272)	(2,849)	(760)	(1,321)	(4,618)	(566)	(0)	-
1110000	AC PR AMR EL PT SR	3032530	POLE ATTACHMENT MGMT SYSTEM	SO	(1,907)	(50)	(523)	(140)	(242)	(848)	(104)	(0)	-
1110000	AC PR AMR EL PT SR	3032590	SUBSTATION/CIRCUIT HISTORY OF OPERATIONS	SO	(2,416)	(63)	(663)	(177)	(307)	(1,074)	(132)	(0)	-
1110000	AC PR AMR EL PT SR	3032600	SINGLE PERSON SCHEDULING	SO	(13,386)	(351)	(3,671)	(979)	(1,702)	(5,952)	(730)	(0)	-
1110000	AC PR AMR EL PT SR	3032640	TIBCO SOFTWARE	SO	(6,908)	(181)	(1,894)	(505)	(878)	(3,071)	(377)	(0)	-
1110000	AC PR AMR EL PT SR	3032680	TRANSMISSION WHOLESALE BILLING SYSTEM	SG	(1,600)	(22)	(430)	(120)	(220)	(718)	(89)	(0)	-
1110000	AC PR AMR EL PT SR	3032690	UTILITY INTERNATIONAL FORECASTING MODEL	SO	(3,673)	(96)	(1,007)	(269)	(467)	(1,633)	(200)	(0)	-
1110000	AC PR AMR EL PT SR	3032710	ROUGE RIVER HYDRO INTANGIBLES	SG	(110)	(2)	(30)	(8)	(15)	(49)	(6)	(0)	-
1110000	AC PR AMR EL PT SR	3032740	GADSBY INTANGIBLE ASSETS	SG	(17)	(0)	(5)	(1)	(2)	(8)	(1)	(0)	-
1110000	AC PR AMR EL PT SR	3032760	SWIFT 2 IMPROVEMENTS	SG	(8,141)	(112)	(2,189)	(610)	(1,122)	(3,654)	(455)	(0)	-
1110000	AC PR AMR EL PT SR	3032770	NORTH UMPQUA - SETTLEMENT AGREEMENT	SG	(283)	(4)	(76)	(21)	(39)	(127)	(16)	(0)	-
1110000	AC PR AMR EL PT SR	3032780	BEAR RIVER-SETTLEMENT AGREEMENT	SG	(74)	(1)	(20)	(6)	(10)	(33)	(4)	(0)	-
1110000	AC PR AMR EL PT SR	3032780	BEAR RIVER-SETTLEMENT AGREEMENT	SG-U	(14)	(0)	(4)	(1)	(2)	(6)	(1)	(0)	-
1110000	AC PR AMR EL PT SR	3032830	VCPRO - VISUALCOMPUSETPRO XEROX CUST STM	SO	(2,629)	(69)	(721)	(192)	(334)	(1,169)	(143)	(0)	-
1110000	AC PR AMR EL PT SR	3032860	WEB SOFTWARE	SO	(10,059)	(264)	(2,759)	(736)	(1,279)	(4,473)	(548)	(0)	-
1110000	AC PR AMR EL PT SR	3032900	IDAHO TRANSMISSION CUSTOMER-OWNED ASSETS	SG	(4,227)	(58)	(1,136)	(316)	(582)	(1,897)	(236)	(0)	-
1110000	AC PR AMR EL PT SR	3032990	P8DM - FILENET P8 DOCUMENT MANAGEMENT (E	SO	(6,793)	(178)	(1,863)	(497)	(864)	(3,021)	(370)	(0)	-
1110000	AC PR AMR EL PT SR	3033090	STEAM PLANT INTANGIBLE ASSETS	SG	(36,548)	(503)	(9,826)	(2,737)	(5,035)	(16,403)	(2,045)	(0)	-
1110000	AC PR AMR EL PT SR	3033190	ITRON METER READING SOFTWARE	CN	(5,868)	(133)	(1,802)	(393)	(417)	(2,875)	(249)	-	-
1110000	AC PR AMR EL PT SR	3033210	ARCFM SOFTWARE	SO	(3,978)	(104)	(1,091)	(291)	(506)	(1,769)	(217)	(0)	-
1110000	AC PR AMR EL PT SR	3033220	MONARCH EMS/SCADA	SO	(22,481)	(590)	(6,166)	(1,645)	(2,859)	(9,996)	(1,226)	(0)	-
1110000	AC PR AMR EL PT SR	3033240	IEE - Itron Enterprise Addition	CN	(4,468)	(101)	(1,372)	(299)	(317)	(2,189)	(190)	-	-
1110000	AC PR AMR EL PT SR	3033250	AMI Metering Software	CN	(24,913)	(564)	(7,650)	(1,667)	(1,769)	(12,206)	(1,058)	-	-
1110000	AC PR AMR EL PT SR	3033260	Big Data & Analytics	SO	(4,995)	(131)	(1,370)	(365)	(635)	(2,221)	(272)	(0)	-

PACIFICORP

Amortization Reserve (Actuals)
Year End: 06/2023
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	3033270	CES - Customer Experience System	CN	(5,282)	(120)	(1,622)	(353)	(375)	(2,588)	(224)	-	-
1110000	AC PR AMR EL PT SR	3033280	MAPAPPS - Mapping Systems Application	SO	(3,313)	(87)	(909)	(242)	(421)	(1,473)	(181)	(0)	-
1110000	AC PR AMR EL PT SR	3033290	CUSTOMER CONTACTS	CN	(1,657)	(38)	(509)	(111)	(118)	(812)	(70)	-	-
1110000	AC PR AMR EL PT SR	3033300	SECID - CUST SECURE WEB LOGIN	CN	(1,085)	(25)	(333)	(73)	(77)	(532)	(46)	-	-
1110000	AC PR AMR EL PT SR	3033310	C&T - ENERGY TRADING SYSTEM	SO	(19,123)	(502)	(5,245)	(1,399)	(2,432)	(8,503)	(1,043)	(0)	-
1110000	AC PR AMR EL PT SR	3033320	CAS - CONTROL AREA SCHEDULING (TRANSM)	SG	(10,076)	(139)	(2,709)	(755)	(1,388)	(4,522)	(564)	(0)	-
1110000	AC PR AMR EL PT SR	3033380	GAS PLANT INTANGIBLES	SG	(889)	(12)	(239)	(67)	(123)	(399)	(50)	(0)	-
1110000	AC PR AMR EL PT SR	3033390	CYME GATEWAY	SO	(923)	(24)	(253)	(68)	(117)	(411)	(50)	(0)	-
1110000	AC PR AMR EL PT SR	3033410	M365	SO	(1,516)	(40)	(416)	(111)	(193)	(674)	(83)	(0)	-
1110000	AC PR AMR EL PT SR	3033420	SUBSTATION RELIABILITY SOFTWARE	SO	(213)	(6)	(58)	(16)	(27)	(95)	(12)	(0)	-
1110000	AC PR AMR EL PT SR	3033430	DEPLOY DISTRIBUTION MGMT SYSTEM	SO	(466)	(12)	(128)	(34)	(59)	(207)	(25)	(0)	-
1110000	AC PR AMR EL PT SR	3033440	DISTRIBUTION ENGINEERING COSTS	SO	(302)	(8)	(83)	(22)	(38)	(134)	(16)	(0)	-
1110000	AC PR AMR EL PT SR	3033450	MAXIMO	SO	(1,814)	(48)	(497)	(133)	(231)	(806)	(99)	(0)	-
1110000	AC PR AMR EL PT SR	3033460	AURORA	SO	(333)	(9)	(91)	(24)	(42)	(148)	(18)	(0)	-
1110000	AC PR AMR EL PT SR	3033470	AUGMENTED REALITY	SO	(361)	(9)	(99)	(26)	(46)	(161)	(20)	(0)	-
1110000	AC PR AMR EL PT SR	3033480	CXP	CN	(271)	(6)	(83)	(18)	(19)	(133)	(12)	-	-
1110000	AC PR AMR EL PT SR	3033490	VMWARE	SO	(669)	(18)	(184)	(49)	(85)	(298)	(37)	(0)	-
1110000	AC PR AMR EL PT SR	3034900	MISC - MISCELLANEOUS	OR	(10)	-	(10)	-	-	-	-	-	-
1110000	AC PR AMR EL PT SR	3034900	MISC - MISCELLANEOUS	SE	(6)	(0)	(1)	(0)	(1)	(2)	(0)	(0)	-
1110000	AC PR AMR EL PT SR	3034900	MISC - MISCELLANEOUS	SG	(19,383)	(267)	(5,211)	(1,451)	(2,670)	(8,699)	(1,084)	(0)	-
1110000	AC PR AMR EL PT SR	3034900	MISC - MISCELLANEOUS	SO	(1,300)	(34)	(357)	(95)	(165)	(578)	(71)	(0)	-
1110000	AC PR AMR EL PT SR	3034900	MISC - MISCELLANEOUS	UT	(6)	-	-	-	-	(6)	-	-	-
1110000	AC PR AMR EL PT SR	3034900	MISC - MISCELLANEOUS	WA	(0)	-	-	(0)	-	-	-	-	-
1110000	AC PR AMR EL PT SR	3034900	MISC - MISCELLANEOUS	WYP	(17)	-	-	-	(17)	-	-	-	-
1110000	AC PR AMR EL PT SR	3035320	HYDRO PLANT INTANGIBLES	SG	(1,006)	(14)	(270)	(75)	(139)	(451)	(56)	(0)	-
1110000	AC PR AMR EL PT SR	3035320	HYDRO PLANT INTANGIBLES	SG-P	(146)	(2)	(39)	(11)	(20)	(65)	(8)	(0)	-
1110000	AC PR AMR EL PT SR	3035322	ACD–Call Center Automated Call Distribut	CN	(4,132)	(94)	(1,269)	(277)	(293)	(2,025)	(175)	-	-
1110000	AC PR AMR EL PT SR	3035330	OATI-OASIS INTERFACE	SO	(1,346)	(35)	(369)	(98)	(171)	(599)	(73)	(0)	-
1110000	AC PR AMR EL PT SR	3316000	STRUCTURES - LEASE IMPROVEMENTS	SG-P	(3,765)	(52)	(1,012)	(282)	(519)	(1,690)	(211)	(0)	-
1110000	AC PR AMR EL PT SR	3456000	Electric Equipment - Leasehold Improveme	OR	(92)	-	(92)	-	-	-	-	-	-
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	(5,064)	-	(5,064)	-	-	-	-	-	-
1110000	AC PR AMR EL PT SR	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	SO	(1,443)	(38)	(396)	(106)	(183)	(642)	(79)	(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	(2,049)	-	-	(2,049)	-	-	-	-	-
1110000	AC PR AMR EL PT SR	3901000	LEASEHOLD IMPROVEMENTS-OFFICE STR	WYP	(4,643)	-	-	-	(4,643)	-	-	-	-
1110000 Total					**(731,618)**	**(16,595)**	**(207,214)**	**(53,647)**	**(87,467)**	**(328,266)**	**(38,430)**	**(0)**	**-**
Grand Total					**(731,618)**	**(16,595)**	**(207,214)**	**(53,647)**	**(87,467)**	**(328,266)**	**(38,430)**	**(0)**	**-**

B19.D.I.T. BALANCE AND I.T.C

PACIFICORP

Deferred Income Tax Balance (Actuals)
Year End: 06/2023
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	194	194	-	-	-	-	-	-	-
1900000	ACM DEF INCM TAXES	287062	DTA 705.347 - ID - Protected PP&E ARAM	IDU	755	-	-	-	-	-	755	-	-
1900000	ACM DEF INCM TAXES	287063	DTA 705.348 - OR - Protected PP&E ARAM	OR	0	-	0	-	-	-	-	-	-
1900000	ACM DEF INCM TAXES	287065	DTA 705.350 - WA - Protected PP&E ARAM	WA	2,139	-	-	2,139	-	-	-	-	-
1900000	ACM DEF INCM TAXES	287066	DTA 705.351 - WY - Protected PP&E ARAM	WYU	4,149	-	-	-	4,149	-	-	-	-
1900000 Total					**7,238**	**194**	**0**	**2,139**	**4,149**	**-**	**755**	**-**	**-**
1901000	ACCUM DEF INC TAX	286945	DTA 715.295 RL-OR Fly Ash	OTHER	345	-	-	-	-	-	-	-	345
1901000	ACCUM DEF INC TAX	287045	DTA 610.155 RL - WA-Plant Closure Cost	WA	833	-	-	833	-	-	-	-	-
1901000	ACCUM DEF INC TAX	287047	DTA 610.150 RL-Bridger Acc Dep&Reclm-OR	OR	2,236	-	2,236	-	-	-	-	-	-
1901000	ACCUM DEF INC TAX	287048	DTA 705.425 RL-Bridger Accel Depr- WA	WA	1,567	-	-	1,567	-	-	-	-	-
1901000	ACCUM DEF INC TAX	287049	DTA 705.352 RL-Klamath Dams Removal-CA	CA	64	64	-	-	-	-	-	-	-
1901000	ACCUM DEF INC TAX	287055	DTA 705.344 RL-Income Tax Deferral-WA	OTHER	1,640	-	-	-	-	-	-	-	1,640
1901000	ACCUM DEF INC TAX	287056	DTA 705.345 RL-Income Tax Deferral-WY	OTHER	329	-	-	-	-	-	-	-	329
1901000	ACCUM DEF INC TAX	287067	DTA 505.450 PMI Accrued Payroll Taxes	SE	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	-
1901000	ACCUM DEF INC TAX	287111	DTA 705.287 RL - Prot PP&E EDIT - CA	CA	7,564	7,564	-	-	-	-	-	-	-
1901000	ACCUM DEF INC TAX	287112	DTA 705.288 RL - Prot PP&E EDIT - ID	IDU	19,331	-	-	-	-	-	19,331	-	-
1901000	ACCUM DEF INC TAX	287113	DTA 705.289 RL - Prot PP&E EDIT - OR	OR	84,277	-	84,277	-	-	-	-	-	-
1901000	ACCUM DEF INC TAX	287114	DTA 705.290 RL - Prot PP&E EDIT - WA	WA	18,339	-	-	18,339	-	-	-	-	-
1901000	ACCUM DEF INC TAX	287115	DTA 705.291 RL - Prot PP&E EDIT - WY	WYP	47,823	-	-	-	47,823	-	-	-	-
1901000	ACCUM DEF INC TAX	287116	DTA 705.292 RL - Prot PP&E EDIT - UT	UT	149,746	-	-	-	-	149,746	-	-	-
1901000	ACCUM DEF INC TAX	287121	DTA 705.294 RL-NonProt PP&E EDIT-CA	CA	25	25	-	-	-	-	-	-	-
1901000	ACCUM DEF INC TAX	287124	DTA 705.296 RL-NonProt PP&E EDIT-WA	WA	3,512	-	-	3,512	-	-	-	-	-
1901000	ACCUM DEF INC TAX	287125	DTA 705.297 RL-NonProt PP&E EDIT-WY	WYP	4,479	-	-	-	4,479	-	-	-	-
1901000	ACCUM DEF INC TAX	287173	DTA 415.942 RL-Steam Decomm-WA	WA	2,194	-	-	2,194	-	-	-	-	-
1901000	ACCUM DEF INC TAX	287174	DTA 705.410 RL-Cholla Decomm-CA	CA	(24)	(24)	-	-	-	-	-	-	-
1901000	ACCUM DEF INC TAX	287175	DTA 705.411 RL-Cholla Decomm-ID	IDU	574	-	-	-	-	-	574	-	-
1901000	ACCUM DEF INC TAX	287176	DTA 705.412 RL-Cholla Decomm-OR	OR	1,857	-	1,857	-	-	-	-	-	-
1901000	ACCUM DEF INC TAX	287177	DTA 705.413 RL-Cholla Decomm-UT	UT	4,348	-	-	-	-	4,348	-	-	-
1901000	ACCUM DEF INC TAX	287178	DTA 705.414 RL-Cholla Decomm-WY	WYP	78	-	-	-	78	-	-	-	-
1901000	ACCUM DEF INC TAX	287191	DTA 705.280 RL Excess Def Inc Taxes CA	CA	6	6	-	-	-	-	-	-	-
1901000	ACCUM DEF INC TAX	287195	DTA 705.284 RL Excess Def Inc Taxes WA	WA	178	-	-	178	-	-	-	-	-
1901000	ACCUM DEF INC TAX	287198	DTA 320.279 FAS 158 Post-Retirement	SO	8,318	218	2,281	609	1,058	3,699	454	0	-
1901000	ACCUM DEF INC TAX	287199	DTA 220.101 Bad Debt	BADDEB	(41)	(1)	(16)	(11)	(2)	(10)	(1)	-	-
1901000	ACCUM DEF INC TAX	287200	DTA 705.267 RL-WA Decoup Mech	OTHER	1,782	-	-	-	-	-	-	-	1,782
1901000	ACCUM DEF INC TAX	287206	DTA 415.710 RL-WA Accel Depr	WA	2,141	-	-	2,141	-	-	-	-	-
1901000	ACCUM DEF INC TAX	287209	DTA 705.266 RL-Energy Savings Assist-CA	OTHER	35	-	-	-	-	-	-	-	35
1901000	ACCUM DEF INC TAX	287211	DTA 425.226 - Deferred Revenue Other	OTHER	918	-	-	-	-	-	-	-	918
1901000	ACCUM DEF INC TAX	287212	DTA 705.245-RL-OR Dir Acc 5 yr Opt Out	OTHER	1,082	-	-	-	-	-	-	-	1,082
1901000	ACCUM DEF INC TAX	287214	DTA 910.245 - Contra Rec Joint Owners	SO	9	0	3	1	1	4	1	0	-
1901000	ACCUM DEF INC TAX	287216	DTA 605.715 Trapper Mine Contract Oblig	SE	2,726	35	718	186	405	1,219	164	0	-
1901000	ACCUM DEF INC TAX	287219	DTA 715.810 Chehalis Mitigation Oblig	SG	58	1	16	4	8	26	3	0	-
1901000	ACCUM DEF INC TAX	287220	DTA 720.560 Pension Liab UMWA Withdraw	SE	28,304	360	7,455	1,930	4,205	12,651	1,702	0	-
1901000	ACCUM DEF INC TAX	287225	DTA 605.103 ARO/Reg Diff - Trojan - WA	WA	43	-	-	43	-	-	-	-	-
1901000	ACCUM DEF INC TAX	287227	DTA 705.531 RL UT Solar Feed-in Tar - NC	OTHER	1,817	-	-	-	-	-	-	-	1,817
1901000	ACCUM DEF INC TAX	287233	DTA 705.515 RL OR Def NPC - Noncurrent	OTHER	498	-	-	-	-	-	-	-	498
1901000	ACCUM DEF INC TAX	287235	DTA 705.511 RL CA Def NPC - Noncurrent	OTHER	990	-	-	-	-	-	-	-	990
1901000	ACCUM DEF INC TAX	287237	DTA 705.755 RL-NONCURRENT RECLASS-OTHER	OTHER	46	-	-	-	-	-	-	-	46
1901000	ACCUM DEF INC TAX	287238	DTA 705.420 RL - CA GHG Allowance Rev	OTHER	3,424	-	-	-	-	-	-	-	3,424
1901000	ACCUM DEF INC TAX	287252	DTA 705.263 Reg Lia - Sale of REC's-WA	OTHER	38	-	-	-	-	-	-	-	38
1901000	ACCUM DEF INC TAX	287253	DTA 705.400 Reg Lia - OR Inj & Dam Reser	OR	1,061	-	1,061	-	-	-	-	-	-
1901000	ACCUM DEF INC TAX	287254	DTA 705.450 Reg Lia - CA Property Ins Re	CA	(828)	(828)	-	-	-	-	-	-	-
1901000	ACCUM DEF INC TAX	287256	DTA 705.452 Reg Lia - WA Property Ins Re	WA	(78)	-	-	(78)	-	-	-	-	-

Deferred Income Tax Balance (Actuals)
Year End: 06/2023
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	287257	DTA 705.453 Reg Lia - ID Property Ins Re	IDU	275	-	-	-	-	-	275	-	-
1901000	ACCUM DEF INC TAX	287258	DTA 705.454 Reg Lia - UT Property Ins Re	UT	(174)	-	-	-	-	(174)	-	-	-
1901000	ACCUM DEF INC TAX	287259	DTA 705.455 Reg Lia - WY Property Ins Re	WYP	137	-	-	-	137	-	-	-	-
1901000	ACCUM DEF INC TAX	287270	Valuation Allowance for DTA	SO	(11,812)	(310)	(3,239)	(864)	(1,502)	(5,252)	(644)	(0)	-
1901000	ACCUM DEF INC TAX	287271	DTA 705.336 RL - Sale of RECs - UT	OTHER	848	-	-	-	-	-	-	-	848
1901000	ACCUM DEF INC TAX	287272	DTA 705.337 RL - Sale of RECs - WY	OTHER	310	-	-	-	-	-	-	-	310
1901000	ACCUM DEF INC TAX	287274	DTA 705.261 Reg Liab-Sale of RECs-OR	OTHER	85	-	-	-	-	-	-	-	85
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	6	132	34	75	224	30	0	-
1901000	ACCUM DEF INC TAX	287299	DTA 705.265 Reg Liab-OR Energy Conservat	OTHER	1,392	-	-	-	-	-	-	-	1,392
1901000	ACCUM DEF INC TAX	287302	DTA-610.114 PMI EITF 04-06 PRE STRIPPING	SE	411	5	108	28	61	183	25	0	-
1901000	ACCUM DEF INC TAX	287304	DTA 610.146 OR REG ASSET/LIAB CONS	OR	(115)	-	(115)	-	-	-	-	-	-
1901000	ACCUM DEF INC TAX	287324	DTA 720.200 Deferred Comp. Accrual - Cas	SO	1,517	40	416	111	193	675	83	0	-
1901000	ACCUM DEF INC TAX	287326	DTA 720.500 Severance Accrual - Cash Ba	SO	765	20	210	56	97	340	42	0	-
1901000	ACCUM DEF INC TAX	287327	DTA 720.300 Pension/Retirement Accrual -	SO	308	8	84	23	39	137	17	0	-
1901000	ACCUM DEF INC TAX	287332	DTA 505.600 Vacation Accrual-Cash Basis	SO	8,323	218	2,283	609	1,058	3,701	454	0	-
1901000	ACCUM DEF INC TAX	287337	DTA 715.105 MCI F.O.G. WIRE LEASE	SG	126	2	34	9	17	57	7	0	-
1901000	ACCUM DEF INC TAX	287338	DTA415.110 Def Reg Asset-Transmission Sr	SG	1,440	20	387	108	198	646	81	0	-
1901000	ACCUM DEF INC TAX	287340	DTA 220.100 Bad Debts Allowance - Cash B	BADDEB	6,246	186	2,432	1,688	318	1,507	114	-	-
1901000	ACCUM DEF INC TAX	287341	DTA 910.530 Injuries & Damages Accrual -	SO	236,711	6,210	64,919	17,319	30,104	105,253	12,906	0	-
1901000	ACCUM DEF INC TAX	287370	DTA 425.215 Unearned Joint Use Pole Cont	SNPD	130	9	33	8	11	64	6	-	-
1901000	ACCUM DEF INC TAX	287371	DTA 930.100 Oregon BETC Credits	SG	280	4	75	21	39	126	16	0	-
1901000	ACCUM DEF INC TAX	287389	DTA 610.145 RL - DSM	OTHER	1,167	-	-	-	-	-	-	-	1,167
1901000	ACCUM DEF INC TAX	287415	DTA 205.200 M&S INV	SNPD	419	28	105	24	36	205	21	-	-
1901000	ACCUM DEF INC TAX	287417	DTA 605.710 ACCRUED FINAL RECLAMATION	OTHER	475	-	-	-	-	-	-	-	475
1901000	ACCUM DEF INC TAX	287430	DTA 505.125 Accrued Royalties	SE	3,885	49	1,023	265	577	1,736	234	0	-
1901000	ACCUM DEF INC TAX	287437	DTA Net Operating Loss Carryforwrd-State	SO	66,114	1,734	18,132	4,837	8,408	29,397	3,605	0	-
1901000	ACCUM DEF INC TAX	287441	DTA 605.100 Trojan Decom Cost-Regulatory	TROJD	1,177	16	315	87	164	528	67	0	-
1901000	ACCUM DEF INC TAX	287449	DTA Federal Detriment of State NOL	SO	(13,927)	(365)	(3,820)	(1,019)	(1,771)	(6,193)	(759)	(0)	-
1901000	ACCUM DEF INC TAX	287473	DTA 705.270 Reg Liab	OTHER	256	-	-	-	-	-	-	-	256
1901000	ACCUM DEF INC TAX	287474	DTA 705.271 Reg Liab	OTHER	114	-	-	-	-	-	-	-	114
1901000	ACCUM DEF INC TAX	287475	DTA 705.272 Reg Liab	OTHER	36	-	-	-	-	-	-	-	36
1901000	ACCUM DEF INC TAX	287476	DTA 705.273 Reg Liab	OTHER	1,182	-	-	-	-	-	-	-	1,182
1901000	ACCUM DEF INC TAX	287477	DTA 705.274 Reg Liab	OTHER	43	-	-	-	-	-	-	-	43
1901000	ACCUM DEF INC TAX	287478	DTA 705.275 Reg Liab	OTHER	139	-	-	-	-	-	-	-	139
1901000	ACCUM DEF INC TAX	287486	DTA 415.926 RL-Depreciation Decrease-OR	OTHER	348	-	-	-	-	-	-	-	348
1901000	ACCUM DEF INC TAX	287681	DTL 920.110 BRIDGER EXTRACTION TAXES PAY	SE	1,533	19	404	105	228	685	92	0	-
1901000	ACCUM DEF INC TAX	287706	DTL 610.100 COAL MINE DEVT PMI	SE	(506)	(6)	(133)	(34)	(75)	(226)	(30)	(0)	-
1901000	ACCUM DEF INC TAX	287720	DTL 610.100 PMI DEV'T COST AMORT	SE	(9)	(0)	(2)	(1)	(1)	(4)	(1)	(0)	-
1901000	ACCUM DEF INC TAX	287722	DTL 505.510 PMI VAC ACCRUAL	SE	106	1	28	7	16	47	6	0	-
1901000	ACCUM DEF INC TAX	287723	DTL 205.411 PMI SEC. 263A	SE	216	3	57	15	32	97	13	0	-
1901000	ACCUM DEF INC TAX	287726	DTL PMI PP&E	SE	(4,660)	(59)	(1,228)	(318)	(692)	(2,083)	(280)	(0)	-
1901000	ACCUM DEF INC TAX	287735	DTL 910.905 PMI COST DEPLETION	SE	(153)	(2)	(40)	(10)	(23)	(68)	(9)	(0)	-
1901000	ACCUM DEF INC TAX	287937	DTA 505.601 PMI - Sick Leave Accrual	SE	3	0	1	0	0	1	0	0	-
1901000	ACCUM DEF INC TAX	287938	DTA 205.205 Inventory Reserve - PMI	SE	0	0	0	0	0	0	0	0	-
1901000	ACCUM DEF INC TAX	287970	DTL 415.815 Insurance Rec Accruals	SO	(93,146)	(2,444)	(25,546)	(6,815)	(11,846)	(41,417)	(5,079)	(0)	-
1901000	ACCUM DEF INC TAX	287971	DTL 415.868 RA UT Solar Incentive Prog	OTHER	(114)	-	-	-	-	-	-	-	(114)
1901000 Total					**616,344**	**12,812**	**156,943**	**47,740**	**83,955**	**261,876**	**33,519**	**0**	**19,500**
2811000	AC DEF TAX-ACCL AM	287960	DTL 105.128 Accel Depr Pollution Cntrl F	SG	(128,320)	(1,767)	(34,498)	(9,609)	(17,678)	(57,591)	(7,179)	(0)	-
2811000 Total					**(128,320)**	**(1,767)**	**(34,498)**	**(9,609)**	**(17,678)**	**(57,591)**	**(7,179)**	**(0)**	**-**
2820000	AC DEF INCTX-PROPT	287704	DTL 105.143/165 Basis Diff - Intangibles	SNP	(249)	(7)	(65)	(18)	(31)	(115)	(14)	(0)	-
2820000 Total					**(249)**	**(7)**	**(65)**	**(18)**	**(31)**	**(115)**	**(14)**	**(0)**	**-**

PACIFICORP

Deferred Income Tax Balance (Actuals)
Year End: 06/2023
Allocation Method - Factor 2020 Protocol
(Allocated in Thousands)

Primary Account		Secondary Account		Alloc	Total	Calif	Oregon	Wash	Wyoming	Utah	Idaho	FERC	Other
2821000	AC DEF TAX-UTILITY	286605	DTL 105.136 PP&E	DITBAL	(384)	(8)	(96)	(27)	(52)	(180)	(22)	(0)	0
2821000	AC DEF TAX-UTILITY	287071	DTL 105.270 - Inc Tax Prop Flowthru-CA	CA	(4,188)	(4,188)	-	-	-	-	-	-	-
2821000	AC DEF TAX-UTILITY	287072	DTL 105.271 - Inc Tax Prop Flowthru-ID	IDU	(1,865)	-	-	-	-	-	(1,865)	-	-
2821000	AC DEF TAX-UTILITY	287073	DTL 105.272 - Inc Tax Prop Flowthru-OR	OR	13,615	-	13,615	-	-	-	-	-	-
2821000	AC DEF TAX-UTILITY	287074	DTL 105.273 - Inc Tax Prop Flowthru-UT	UT	56,122	-	-	-	-	56,122	-	-	-
2821000	AC DEF TAX-UTILITY	287075	DTL 105.274 - Inc Tax Prop Flowthru-WA	WA	(1,731)	-	-	(1,731)	-	-	-	-	-
2821000	AC DEF TAX-UTILITY	287076	DTL 105.275 - Inc Tax Prop Flowthru-WY	WYP	(18,532)	-	-	-	(18,532)	-	-	-	-
2821000	AC DEF TAX-UTILITY	287221	DTA 415.933 RL Contra-Carbon Decomm-ID	IDU	725	-	-	-	-	-	725	-	-
2821000	AC DEF TAX-UTILITY	287222	DTA 415.934 RL Contra-Carbon Decomm-UT	UT	10,482	-	-	-	-	10,482	-	-	-
2821000	AC DEF TAX-UTILITY	287223	DTA 415.935 RL Contra-Carbon Decomm-WY	WYP	2,788	-	-	-	2,788	-	-	-	-
2821000	AC DEF TAX-UTILITY	287605	DTL PP&E Powertax	DITBAL	(3,020,474)	(59,059)	(753,625)	(212,894)	(408,272)	(1,417,528)	(169,841)	(0)	746
2821000	AC DEF TAX-UTILITY	287607	DTL PMI PP&E	SE	(1,650)	(21)	(435)	(113)	(245)	(738)	(99)	(0)	-
2821000	AC DEF TAX-UTILITY	287766	DTL 610.100N Amort	SO	1	0	0	0	0	1	0	0	-
2821000	AC DEF TAX-UTILITY	287771	DTL 110.205 SRC tax depletion	SE	38	0	10	3	6	17	2	0	-
2821000	AC DEF TAX-UTILITY	287928	DTL 425.310 Hydro Relicensing Obligation	OTHER	(2,545)	-	-	-	-	-	-	-	(2,545)
2821000 Total					**(2,967,598)**	**(63,275)**	**(740,530)**	**(214,763)**	**(424,307)**	**(1,351,824)**	**(171,100)**	**(0)**	**(1,799)**
2830000	ACC DEF TAX-OTHER	287936	DTL 205.025 PMI Fuel Cost Adjustment	SE	(613)	(8)	(161)	(42)	(91)	(274)	(37)	(0)	-
2830000 Total					**(613)**	**(8)**	**(161)**	**(42)**	**(91)**	**(274)**	**(37)**	**(0)**	**-**
2831000	AC DEF IN TX UTIL	286887	DTL 320.286 RA-Pension Settlement-OR	OTHER	(2,644)	-	-	-	-	-	-	-	(2,644)
2831000	AC DEF IN TX UTIL	286888	DTL 320.287 RA-Pension Settlement-UT	OTHER	(1,133)	-	-	-	-	-	-	-	(1,133)
2831000	AC DEF IN TX UTIL	286889	DTL 320.288 RA-Pension Settlement-WY	WYU	(1,221)	-	-	-	(1,221)	-	-	-	-
2831000	AC DEF IN TX UTIL	286890	DTL 415.100 RA - Equity Adv Group - WA	OTHER	(254)	-	-	-	-	-	-	-	(254)
2831000	AC DEF IN TX UTIL	286891	DTL 415.943-RA-COV19 Bill Assist Prg-OR	OTHER	(2,932)	-	-	-	-	-	-	-	(2,932)
2831000	AC DEF IN TX UTIL	286892	DTL 415.944-RA-COV19 Bill Assist Prg-WA	OTHER	(763)	-	-	-	-	-	-	-	(763)
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	286894	DTL 415.261 RA-Wildland Fire Protect–UT	OTHER	(2,130)	-	-	-	-	-	-	-	(2,130)
2831000	AC DEF IN TX UTIL	286895	DTL 415.262 RA-Wildfire Mitigation-OR	OTHER	(15,617)	-	-	-	-	-	-	-	(15,617)
2831000	AC DEF IN TX UTIL	286896	DTL 415.734 RA-Cholla Unrec Plant-CA	CA	(965)	(965)	-	-	-	-	-	-	-
2831000	AC DEF IN TX UTIL	286898	DTL 415.736 RA-Cholla Unrec Plant-WY	WYP	(8,430)	-	-	-	(8,430)	-	-	-	-
2831000	AC DEF IN TX UTIL	286901	DTL 415.938 RA - Carbon Plt Dec/Inv-CA	CA	0	0	-	-	-	-	-	-	-
2831000	AC DEF IN TX UTIL	286908	DTL 210.201 Property Tax	GPS	(3,392)	(89)	(930)	(248)	(431)	(1,508)	(185)	(0)	-
2831000	AC DEF IN TX UTIL	286909	DTL 720.815 Post-Retirement Asset	SO	(10,505)	(276)	(2,881)	(769)	(1,336)	(4,671)	(573)	(0)	-
2831000	AC DEF IN TX UTIL	286910	DTL 415.200 RA-OR Transp Elect PilotPgm	OTHER	135	-	-	-	-	-	-	-	135
2831000	AC DEF IN TX UTIL	286911	DTL 415.430 - RA-Transp Elect Pilot-CA	OTHER	58	-	-	-	-	-	-	-	58
2831000	AC DEF IN TX UTIL	286912	DTL 415.431 - RA-Transp Elect Pilot-WA	OTHER	(202)	-	-	-	-	-	-	-	(202)
2831000	AC DEF IN TX UTIL	286913	DTL 415.720 RA-OR Community Solar	OTHER	(731)	-	-	-	-	-	-	-	(731)
2831000	AC DEF IN TX UTIL	286917	DTL 415.260 RA-Fire Risk Mitigation-CA	OTHER	(8,928)	-	-	-	-	-	-	-	(8,928)
2831000	AC DEF IN TX UTIL	286918	DTL 210.175 - Prepaid - FSA O&M - East	SG	(924)	(13)	(248)	(69)	(127)	(415)	(52)	(0)	-
2831000	AC DEF IN TX UTIL	286919	DTL 210.170 - Prepaid - FSA O&M - West	SG	(259)	(4)	(70)	(19)	(36)	(116)	(14)	(0)	-
2831000	AC DEF IN TX UTIL	286925	DTL 415.728 Contra RA-Cholla U4-OR	OTHER	(150)	-	-	-	-	-	-	-	(150)
2831000	AC DEF IN TX UTIL	286926	DTL 415.729 Contra RA-Cholla U4-UT	UT	304	-	-	-	-	304	-	-	-
2831000	AC DEF IN TX UTIL	286927	DTL 415.730 Contra RA-Cholla U4-WY	WYP	101	-	-	-	101	-	-	-	-
2831000	AC DEF IN TX UTIL	286928	DTL 415.833 RA-Pension Settlement-CA	OTHER	(319)	-	-	-	-	-	-	-	(319)
2831000	AC DEF IN TX UTIL	286929	DTL 415.841 RA-Emerg Svc Prgms-BS-CA	OTHER	56	-	-	-	-	-	-	-	56
2831000	AC DEF IN TX UTIL	286930	DTL 415.426-RA-2020 GRC-AMI Meter-OR	OTHER	(2,333)	-	-	-	-	-	-	-	(2,333)
2831000	AC DEF IN TX UTIL	286933	DTL 415.645 RA-Oregon OCAT Expense Def	OTHER	130	-	-	-	-	-	-	-	130
2831000	AC DEF IN TX UTIL	286935	DTL 415.251 RA-LowCarbon Enrgy Stnds-WY	OTHER	(18)	-	-	-	-	-	-	-	(18)
2831000	AC DEF IN TX UTIL	286936	DTL 415.255 RA-Wind Test Enrgy Def - WY	WYU	(52)	-	-	-	(52)	-	-	-	-
2831000	AC DEF IN TX UTIL	286937	DTL 415.270 RA-ElectricVehChrg Infra-UT	OTHER	1,801	-	-	-	-	-	-	-	1,801
2831000	AC DEF IN TX UTIL	286938	DTL 415.646 Reg Asset - OR Metro BIT	OTHER	(5)	-	-	-	-	-	-	-	(5)
2831000	AC DEF IN TX UTIL	286941	DTL 415.440 RA-Low Income Bill Disc-OR	OTHER	(832)	-	-	-	-	-	-	-	(832)
2831000	AC DEF IN TX UTIL	286942	DTL 415.441 RA-Utility Community AG-OR	OTHER	(34)	-	-	-	-	-	-	-	(34)

PACIFICORP

Deferred Income Tax Balance (Actuals)
Year End: 06/2023
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	286943	DTL 415.263 RA-Wildfire DamagedAsset-OR	OR	(462)	-	(462)	-	-	-	-	-	-
2831000	AC DEF IN TX UTIL	286944	DTL 415.252-RA-Distrib System Plan - OR	OTHER	(368)	-	-	-	-	-	-	-	(368)
2831000	AC DEF IN TX UTIL	286946	DTL 415.264 RA-OR TB Flats	OTHER	(1,694)	-	-	-	-	-	-	-	(1,694)
2831000	AC DEF IN TX UTIL	286949	DTL 415.305 RA-Cedar Springs II-OR	OTHER	(67)	-	-	-	-	-	-	-	(67)
2831000	AC DEF IN TX UTIL	287070	DTL 415.445 RA-Klamath Unrec Plant	SG	(1,273)	(18)	(342)	(95)	(175)	(571)	(71)	(0)	-
2831000	AC DEF IN TX UTIL	287569	DTL 720.800 FAS 158 Pension Liability	SO	(14,540)	(381)	(3,988)	(1,064)	(1,849)	(6,465)	(793)	(0)	-
2831000	AC DEF IN TX UTIL	287570	DTL 415.701 CA Deferred Intervenor Fundi	OTHER	(103)	-	-	-	-	-	-	-	(103)
2831000	AC DEF IN TX UTIL	287571	DTL 415.702 Reg Asset-Lake Side Liq. Dam	WYU	(163)	-	-	-	(163)	-	-	-	-
2831000	AC DEF IN TX UTIL	287576	DTL 430.110 REG ASSET RECLASS	OTHER	(1,167)	-	-	-	-	-	-	-	(1,167)
2831000	AC DEF IN TX UTIL	287590	DTL 415.840 Reg Asset - Deferred OR Ind	OTHER	(29)	-	-	-	-	-	-	-	(29)
2831000	AC DEF IN TX UTIL	287591	DTL 415.301 Environmental Clean-up Accrl	WA	872	-	-	872	-	-	-	-	-
2831000	AC DEF IN TX UTIL	287593	DTL 415.874 Deferred Net Power Costs-WY	OTHER	(28,253)	-	-	-	-	-	-	-	(28,253)
2831000	AC DEF IN TX UTIL	287596	DTL 415.892 Deferred Net Power Costs - I	OTHER	(12,672)	-	-	-	-	-	-	-	(12,672)
2831000	AC DEF IN TX UTIL	287597	DTL 415.703 Goodnoe Hills Liquidation Da	WYP	(55)	-	-	-	(55)	-	-	-	-
2831000	AC DEF IN TX UTIL	287601	DTL 415.677 RA Pref Stock Redemption WA	OTHER	(2)	-	-	-	-	-	-	-	(2)
2831000	AC DEF IN TX UTIL	287614	DTL 430.100 Weatherization	OTHER	(55,077)	-	-	-	-	-	-	-	(55,077)
2831000	AC DEF IN TX UTIL	287634	DTL 415.300 Environmental Clean-up Accru	SO	(35,397)	(929)	(9,708)	(2,590)	(4,502)	(15,739)	(1,930)	(0)	-
2831000	AC DEF IN TX UTIL	287640	DTL 415.680 Deferred Intervener Funding	OTHER	(876)	-	-	-	-	-	-	-	(876)
2831000	AC DEF IN TX UTIL	287647	DTL 425.100 IDAHO DEFERRED REGULATORY EX	IDU	(10)	-	-	-	-	-	(10)	-	-
2831000	AC DEF IN TX UTIL	287661	DTL 425.360 Hermiston Swap	SG	(552)	(8)	(148)	(41)	(76)	(248)	(31)	(0)	-
2831000	AC DEF IN TX UTIL	287662	DTL 210.100 Prepaid Taxes - OR PUC	OR	(1,119)	-	(1,119)	-	-	-	-	-	-
2831000	AC DEF IN TX UTIL	287664	DTL 210.120 Prepaid Taxes - UT PUC	UT	(1,699)	-	-	-	-	(1,699)	-	-	-
2831000	AC DEF IN TX UTIL	287665	DTL 210.130 Prepaid Taxes - ID PUC	IDU	(77)	-	-	-	-	-	(77)	-	-
2831000	AC DEF IN TX UTIL	287669	DTL 210.180 PRE MEM	SO	(1,042)	(27)	(286)	(76)	(133)	(463)	(57)	(0)	-
2831000	AC DEF IN TX UTIL	287675	DTL 740.100 Post Merger Loss-Reacq Debt	SNP	(538)	(15)	(141)	(38)	(68)	(247)	(30)	(0)	-
2831000	AC DEF IN TX UTIL	287685	DTL 425.380 Idaho Customer Balancing Acc	OTHER	(360)	-	-	-	-	-	-	-	(360)
2831000	AC DEF IN TX UTIL	287708	DTL 210.200 PREPAID PROPERTY TAXES	GPS	(5,793)	(152)	(1,589)	(424)	(737)	(2,576)	(316)	(0)	-
2831000	AC DEF IN TX UTIL	287738	DTL 320.270 Reg Asset FAS 158 Pension	SO	(63,560)	(1,667)	(17,432)	(4,650)	(8,083)	(28,262)	(3,466)	(0)	-
2831000	AC DEF IN TX UTIL	287739	DTL 320.280 Reg Asset FAS 158 Post-Ret	SO	66	2	18	5	8	29	4	0	-
2831000	AC DEF IN TX UTIL	287747	DTL 705.240 CA Energy Program	OTHER	(111)	-	-	-	-	-	-	-	(111)
2831000	AC DEF IN TX UTIL	287770	DTL 120.205 TRAPPER MINE-EQUITY EARNINGS	OTHER	(641)	-	-	-	-	-	-	-	(641)
2831000	AC DEF IN TX UTIL	287781	DTL 415.870 Def CA	OTHER	(4,111)	-	-	-	-	-	-	-	(4,111)
2831000	AC DEF IN TX UTIL	287840	DTL 415.410 RA Energy West Mining	SE	(48,001)	(610)	(12,643)	(3,274)	(7,132)	(21,455)	(2,887)	(0)	-
2831000	AC DEF IN TX UTIL	287841	DTL 415.411 ContraRA DeerCreekAband CA	CA	314	314	-	-	-	-	-	-	-
2831000	AC DEF IN TX UTIL	287842	DTL 415.412 ContraRA DeerCreekAband ID	IDU	352	-	-	-	-	-	352	-	-
2831000	AC DEF IN TX UTIL	287843	DTL 415.413 ContraRA DeerCreekAband OR	OR	629	-	629	-	-	-	-	-	-
2831000	AC DEF IN TX UTIL	287845	DTL 415.415 ContraRA DeerCreekAband WA	WA	1,053	-	-	1,053	-	-	-	-	-
2831000	AC DEF IN TX UTIL	287846	DTL 415.416 ContraRA DeerCreekAband WY	WYU	848	-	-	-	848	-	-	-	-
2831000	AC DEF IN TX UTIL	287848	DTL 320.281 RA Post-Ret Settlement Loss	SO	(162)	(4)	(44)	(12)	(21)	(72)	(9)	(0)	-
2831000	AC DEF IN TX UTIL	287849	DTL 415.424 ContraRA DeerCreekAband	SE	13,437	171	3,539	916	1,996	6,006	808	0	-
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	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	(5)	-	-	-	-	-	-	-	(5)
2831000	AC DEF IN TX UTIL	287860	DTL 415.855 Reg Asset-CA-Jan10 Storm Cos	OTHER	50	-	-	-	-	-	-	-	50
2831000	AC DEF IN TX UTIL	287861	DTL 415.857 Reg Asset-ID-Def Overburden	OTHER	(168)	-	-	-	-	-	-	-	(168)
2831000	AC DEF IN TX UTIL	287868	DTL 415.858 Reg Asset-WY-Def Overburden	WYP	(413)	-	-	-	(413)	-	-	-	-
2831000	AC DEF IN TX UTIL	287870	DTL 415.865 Reg Asset-UT Major Plant Add	OTHER	(0)	-	-	-	-	-	-	-	(0)
2831000	AC DEF IN TX UTIL	287871	DTL 415.866 Reg Asset-OR Solar Feed-In T	OTHER	(871)	-	-	-	-	-	-	-	(871)
2831000	AC DEF IN TX UTIL	287882	DTL 415.876 Deferred Net Power Costs-OR	OTHER	(29,468)	-	-	-	-	-	-	-	(29,468)
2831000	AC DEF IN TX UTIL	287888	DTL 415.882 Def of Excess RECs WA	OTHER	0	-	-	-	-	-	-	-	0
2831000	AC DEF IN TX UTIL	287896	DTL 415.875 Def Net Power Cost - UT	OTHER	(78,646)	-	-	-	-	-	-	-	(78,646)
2831000	AC DEF IN TX UTIL	287899	DTL 415.878 RA-UT Liq Damages	UT	(90)	-	-	-	-	(90)	-	-	-

PACIFICORP

Deferred Income Tax Balance (Actuals)
Year End: 06/2023
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	287903	DTL 415.879 RA-Liq Damages N2-WY	WYP	(15)	-	-	-	(15)	-	-	-	-
2831000	AC DEF IN TX UTIL	287906	DTL 415.863 RA-UT Subscriber Solar Prog	UT	(458)	-	-	-	-	(458)	-	-	-
2831000	AC DEF IN TX UTIL	287907	DTL 210.185-Prepaid Aircraft Maint Cost	SG	(27)	(0)	(7)	(2)	(4)	(12)	(2)	(0)	-
2831000	AC DEF IN TX UTIL	287908	DTL 210.190 - Prepaid Water Rights	SG	(120)	(2)	(32)	(9)	(17)	(54)	(7)	(0)	-
2831000	AC DEF IN TX UTIL	287917	DTL 705.451 - RL - OR Property Ins Res	OR	(7,779)	-	(7,779)	-	-	-	-	-	-
2831000	AC DEF IN TX UTIL	287919	DTL 425.105 RA-OR Asset Sale Gain GB-NC	OTHER	(787)	-	-	-	-	-	-	-	(787)
2831000	AC DEF IN TX UTIL	287935	DTL 415.936 RA - Carbon Plt Decom/Inv	SG	(155)	(2)	(42)	(12)	(21)	(70)	(9)	(0)	-
2831000	AC DEF IN TX UTIL	287939	DTL 415.115 RA-UT STEP Pilot Program	OTHER	1,593	-	-	-	-	-	-	-	1,593
2831000	AC DEF IN TX UTIL	287942	DTL 430.112 Reg Asset - Other - Balance	OTHER	(6,279)	-	-	-	-	-	-	-	(6,279)
2831000	AC DEF IN TX UTIL	287971	DTL 415.868 RA UT Solar Incentive Prog	OTHER	(1,593)	-	-	-	-	-	-	-	(1,593)
2831000	AC DEF IN TX UTIL	287975	DTL 415.655 RA - CA GHG Allowances	OTHER	(1,386)	-	-	-	-	-	-	-	(1,386)
2831000	AC DEF IN TX UTIL	287977	DTL 415.885 RA-NONCURRENT RECLASS-OTHER	OTHER	(46)	-	-	-	-	-	-	-	(46)
2831000	AC DEF IN TX UTIL	287978	DTL 415.906 RA OR RECs in Rate - NC	OTHER	(29)	-	-	-	-	-	-	-	(29)
2831000	AC DEF IN TX UTIL	287981	DTL 415.920 RA-Depreciation Increase-ID	IDU	(2,142)	-	-	-	-	-	(2,142)	-	-
2831000	AC DEF IN TX UTIL	287982	DTL 415.921 RA-Depreciation Increase-UT	UT	(252)	-	-	-	-	(252)	-	-	-
2831000	AC DEF IN TX UTIL	287983	DTL 415.922 RA-Depreciation Increase-WY	WYP	(870)	-	-	-	(870)	-	-	-	-
2831000	AC DEF IN TX UTIL	287985	DTL 415.924 RA-Carbon Unrec Plant - UT	UT	(3,033)	-	-	-	-	(3,033)	-	-	-
2831000	AC DEF IN TX UTIL	287996	DTL 415.675 RA Pref Stock Redemption-UT	OTHER	(14)	-	-	-	-	-	-	-	(14)
2831000	AC DEF IN TX UTIL	287997	DTL 415.862 RA-CA Mobile Home Park Conv	OTHER	(49)	-	-	-	-	-	-	-	(49)
2831000 Total					**(454,547)**	**(4,675)**	**(55,704)**	**(10,610)**	**(33,011)**	**(82,138)**	**(11,495)**	**(0)**	**(256,915)**
Grand Total					**(2,927,746)**	**(56,726)**	**(674,015)**	**(185,161)**	**(387,014)**	**(1,230,065)**	**(155,550)**	**(0)**	**(239,215)**

Investment Tax Credit Balance (Actuals)
Year End: 06/2023
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	(101)	(1)	(27)	(8)	(14)	(45)	(6)	(0)	-
2551000	ACC DEF ITC - FED	285621	Accum Def ITC - Solar Arrays - 2014	SG	(69)	(1)	(19)	(5)	(9)	(31)	(4)	(0)	-
2551000	ACC DEF ITC - FED	285622	Accum Def ITC - Solar Battery	UT	(1,188)	-	-	-	-	(1,188)	-	-	-
2551000	ACC DEF ITC - FED	285623	Accum Def ITC - Solar Facility	UT	(884)	-	-	-	-	(884)	-	-	-
2551000 Total					**(2,242)**	**(2)**	**(46)**	**(13)**	**(23)**	**(2,148)**	**(9)**	**(0)**	**-**
2552000	ACC DEF ITC-IDAHO	285612	Acc Def Idaho ITC-ID situs ATL	IDU	(19)	-	-	-	-	-	(19)	-	-
2552000 Total					**(19)**	**-**	**-**	**-**	**-**	**-**	**(19)**	**-**	**-**
Grand Total					**(2,261)**	**(2)**	**(46)**	**(13)**	**(23)**	**(2,148)**	**(29)**	**(0)**	**-**

B20. CUSTOMER ADVANCES

Customer Advances (Actuals)
Year End: 06/2023
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	IDU	(428)	-	-	-	-	-	(428)	-	-
2520000	CUST ADV CONSTRUCT	210550	Payments Received Uncompleted Projects	OR	(30,378)	-	(30,378)	-	-	-	-	-	-
2520000	CUST ADV CONSTRUCT	210550	Payments Received Uncompleted Projects	SG	(65,682)	(904)	(17,658)	(4,918)	(9,049)	(29,478)	(3,674)	(0)	-
2520000	CUST ADV CONSTRUCT	210550	Payments Received Uncompleted Projects	UT	(335)	-	-	-	-	(335)	-	-	-
2520000	CUST ADV CONSTRUCT	210550	Payments Received Uncompleted Projects	WA	(56)	-	-	(56)	-	-	-	-	-
2520000	CUST ADV CONSTRUCT	210553	Transmission Payments Received - Capital	SG	(6,844)	(94)	(1,840)	(512)	(943)	(3,071)	(383)	(0)	-
2520000	CUST ADV CONSTRUCT	210556	NET METER FEES-REFUNDABLE	UT	(23)	-	-	-	-	(23)	-	-	-
2520000	CUST ADV CONSTRUCT	210556	NET METER FEES-REFUNDABLE	WA	(6)	-	-	(6)	-	-	-	-	-
2520000	CUST ADV CONSTRUCT	285460	Transm Intercon Deposits - w/3rd Party	SG	(89,669)	(1,235)	(24,107)	(6,715)	(12,353)	(40,244)	(5,016)	(0)	-
2520000 Total					**(193,420)**	**(2,233)**	**(73,982)**	**(12,207)**	**(22,344)**	**(73,151)**	**(9,502)**	**(0)**	**-**
Grand Total					**(193,420)**	**(2,233)**	**(73,982)**	**(12,207)**	**(22,344)**	**(73,151)**	**(9,502)**	**(0)**	**-**

REDACTED
Docket No. UE 433
Exhibit PAC/1703
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

February 2024

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

REDACTED
Docket No. UE 433
Exhibit PAC/1704
Witness: Sherona L. Cheung

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

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Exhibit Accompanying Direct Testimony of Sherona L. Cheung

Pro Forma Wage Escalators

February 2024

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REDACTED
Docket No. UE 433
Exhibit PAC/1705
Witness: Sherona L. Cheung

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

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IHS Markit Escalation Indices

February 2024

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Docket No. UE 433
Exhibit PAC/1706
Witness: Sherona L. Cheung

BEFORE THE PUBLIC UTILITY COMMISSION

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REC Revenues Adjustment Support

February 2024

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Docket No. UE 433
Exhibit PAC/1707
Witness: Sherona L. Cheung

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Bridger Mine Reclamation Support

February 2024

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Docket No. UE 433
Exhibit PAC/1708
Witness: Sherona L. Cheung

BEFORE THE PUBLIC UTILITY COMMISSION

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New Wind Generation Capital Additions Support

February 2024

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Docket No. UE 433
Exhibit PAC/1709
Witness: Sherona L. Cheung

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

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Exhibit Accompanying Direct Testimony of Sherona L. Cheung

Insurance Premium Deferral Amortization

February 2024

PacifiCorp

Oregon General Rate Case - December 2025

Excess Liability Insurance Premiums Deferral & Amortization

8/15/2023 renewal premiums	122,577,486
Premiums in Oregon base rates (UE 399)	29,182,860
Incremental premiums - 2023/24 renewal	93,394,626
8/15/2024 estimated renewal premiums	183,866,229
Premiums in Oregon base rates (UE 399)	29,182,860
Estimated incremental premiums - 2024/25 renewal	154,683,369

		Opening Bal.	Accrual	Amortization	Interest[1,2]	Ending Bal.
2023	June	-	-	-	-	-
	July	-	-	-	-	-
	August	-	2,761,669	-	8,180	2,769,849
	September	2,769,849	7,782,885	-	39,461	10,592,195
	October	10,592,195	7,782,885	-	85,800	18,460,881
	November	18,460,881	7,782,885	-	132,413	26,376,180
	December	26,376,180	7,782,885	-	179,303	34,338,368
2024	January	34,338,368	7,782,885	-	226,470	42,347,724
	February	42,347,724	7,782,885	-	273,917	50,404,527
	March	50,404,527	7,782,885	-	321,645	58,509,057
	April	58,509,057	7,782,885	-	369,656	66,661,598
	May	66,661,598	7,782,885	-	417,951	74,862,434
	June	74,862,434	7,782,885	-	466,532	83,111,851
	July	83,111,851	7,782,885	-	515,401	91,410,137
	August	91,410,137	10,583,715	-	572,855	102,566,707
	September	102,566,707	12,890,281	-	645,777	116,102,765
	October	116,102,765	12,890,281	-	725,964	129,719,010
	November	129,719,010	12,890,281	-	806,625	143,415,916
	December	143,415,916	12,890,281	-	887,765	157,193,962
2025	January	157,193,962	-	(4,728,887)	696,733	153,161,808
	February	153,161,808	-	(4,728,887)	678,588	149,111,509
	March	149,111,509	-	(4,728,887)	660,362	145,042,985
	April	145,042,985	-	(4,728,887)	642,053	140,956,151
	May	140,956,151	-	(4,728,887)	623,663	136,850,928
	June	136,850,928	-	(4,728,887)	605,189	132,727,230
	July	132,727,230	-	(4,728,887)	586,633	128,584,976
	August	128,584,976	-	(4,728,887)	567,992	124,424,082
	September	124,424,082	-	(4,728,887)	549,268	120,244,464
	October	120,244,464	-	(4,728,887)	530,460	116,046,037
	November	116,046,037	-	(4,728,887)	511,567	111,828,718
	December	111,828,718	-	(4,728,887)	492,589	107,592,420
			Pro Forma Annual Amort =	**(56,746,639)**		
			Oregon SO Factor	**27.4255%**		
			Oregon Annual Amortization	**(15,563,030)**		

Note:

1. Interest rate in deferral period per approved WACC from UE-399 effective 1/1/2023.

	UE-399
WACC	7.11%

2. Interest accrual at Modified Blended Treasury Rate as of date of the Commission's approval of the amortization (i.e. Dec 2024)

	2024	
MBTR	5.400%	Ref UM-1147

Docket No. UE 433
Exhibit PAC/1710
Witness: Sherona L. Cheung

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Sherona L. Cheung

Wildfire Mitigation Plan Automatic Adjustment Clause True-Up Illustration

February 2024

PacifiCorp
Oregon General Rate Case - December 2025
2023 Wildfire Protection Plan
Automatic Adjustment Clause - UPDATED

ADV 1529
Approved 1/9/24

	UPDATED 2023 WMP AAC										
	For Rates Effective Jan-2025										
	Total Company	Oregon Allocated	Original	Corrected	Remove non-Oregon Transmission	Other Capital Adjustments [1]	O&M Adjustments [2]	Capital Indirect Loading	Add Back Base Rate O&M	Add Back Base Rate Capital
Incremental Capital Costs	18,043,689	13,223,344								
Annual Revenue Requirement	**2,615,038**	**1,612,120**	**942,580**	**878,127**	**322,744**	**321,504**	**321,504**	**47,427**	**47,427**	**1,612,120**
2022 Outstanding Deferral Balance		**27,867,357**	**27,903,607**	**27,903,607**	**27,903,607**	**27,903,607**	**27,867,357**	**27,867,357**	**27,867,357**	**27,867,357**
2023 Incremental WMP O&M		**38,246,118**	**18,586,716**	**18,586,716**	**18,586,716**	**18,586,716**	**18,586,716**	**18,586,716**	**38,246,118**	**38,246,118**
Total 2023 WMP AAC		**67,725,595**	**47,432,903**	**47,368,450**	**46,813,066**	**46,811,826**	**46,775,577**	**46,501,500**	**66,160,902**	**67,725,595**
			Variance	(64,453)	(555,383)	(1,240)	(36,249)	(274,077)	19,659,402	1,564,693
									Total True-Up	**21,224,095**

Notes:
1 Removal of capitalized meals (25% per settlement), and weather stations reframe project costs
2 Overhead costs and meals

PacifiCorp
Oregon General Rate Case - December 2025
Revenue Requirement for Recovery
2023 WMP Automatic Adjustment Clause
Updated WMP AAC Rate - Effective January 1, 2025

2023 WMP Automatic Adjustment Clause

	For Rates Effective Jan-2025			
	Total Company	**Factor**	**Factor %**	**Oregon Allocated**
Capital Investment				
Distribution	10,632,306	OR	100.0000%	10,632,306
Transmission	2,671,547	SG	26.0018%	694,649
General - System	3,899,761	SO	27.0866%	1,056,313
General - Situs	840,076	OR	100.0000%	840,076
General - SO	4,103,064	SO	27.0866%	1,111,381
General - SG	539,155	SG	26.0018%	140,190
Depreciation Reserve				
Distribution	(289,057)	OR	100.0000%	(289,057)
Transmission	(107,012)	SG	26.0018%	(27,825)
Intangibles	(1,041,430)	SO	27.0866%	(282,088)
General - Situs	(80,025)	OR	100.0000%	(80,025)
General - SO	(151,637)	SO	27.0866%	(41,073)
General - SG	(29,907)	SG	26.0018%	(7,776)
Accumulated DIT Balance				
Distribution	(144,681)	OR	100.0000%	(144,681)
Transmission	(110,615)	SG	26.0018%	(28,762)
Intangibles	(423,307)	SO	27.0866%	(114,660)
General - Situs	(107,616)	OR	100.0000%	(107,616)
General - SO	(198,073)	SO	27.0866%	(53,651)
General - SG	(51,821)	SG	26.0018%	(13,474)
Working Capital	-	SG	26.0018%	-
Net Rate Base	19,950,727			13,284,227
	8.66%			8.66%
Pre-Tax Return on Rate Base	1,727,242			1,150,087
Depreciation				
Distribution	241,498	OR	100.0000%	241,498
Transmission	46,049	SG	26.0018%	11,974
Intangibles	240,050	SO	27.0866%	65,021
General - Situs	21,648	OR	100.0000%	21,648
General - SO	232,082	SO	27.0866%	62,863
General - SG	18,534	SG	26.0018%	4,819
Property Taxes				
Rev. Reqt. Before Franchise Tax & Bad Debt	2,527,103			1,557,911
Franchise Taxes (2.303%)	60,218			37,123
Bad Debt Expense (0.505%)	13,199			8,137
Resource Suppliers Tax (0.125%)	3,273			2,018
PUC Fee (0.430%)	11,245			6,932
Total Revenue Requirement	**2,615,038**			**1,612,120**
	-			-
		2022 WMP Outstanding Deferral Balance[1]		**27,867,357**
2023 WMP Forecast O&M - Includes to $19.7 million approved in Base Rates per UE-399				**38,246,118**
		2023 WMP AAC Total		**67,725,595**

PacifiCorp
Oregon General Rate Case - December 2025
2023 Wildfire Mitigation Plan - Automatic Adjustment Clause
Annual Revenue Requirement of Incremental Capital Investments
Updated WMP AAC Rate - Effective January 1, 2025

	2023 WMP AAC Incremental Capital - Total Company 12 months starting Jan 2025			2023 WMP AAC Incremental Capital - Oregon Allocated 12 months starting Jan 2025		
	Total Company	**Price Change**	**Results with Price Change**	**Oregon Allocated**	**Price Change**	**Results with Price Change**
Operating Revenues:						
General Business Revenues	-	2,615,037	2,615,037	-	1,612,120	1,612,120
Interdepartmental	-	-	-	-	-	-
Special Sales	-	-	-	-	-	-
Other Operating Revenues	-	-	-	-	-	-
Total Operating Revenues	-	2,615,037	2,615,037	-	1,612,120	1,612,120
Operating Expenses:						
Customer Accounting	-	13,199	13,199	-	8,137	8,137
Total O&M Expenses	-	13,199	13,199	-	8,137	8,137
Depreciation						
Distribution	241,498	-	241,498	241,498	-	241,498
Transmission	46,049	-	46,049	11,974	-	11,974
Intangibles	240,050	-	240,050	65,021	-	65,021
General - Situs	21,648	-	21,648	21,648	-	21,648
General - SO	232,082	-	232,082	62,863	-	62,863
General - SG	18,534	-	18,534	4,819	-	4,819
Amortization	-	-	-	-	-	-
Taxes Other Than Income	-	74,736	74,736	-	46,073	46,073
Income Taxes - Federal	(702,184)	506,598	(195,586)	(423,771)	312,308	(111,463)
Income Taxes - State	(159,025)	114,730	(44,295)	(95,972)	70,729	(25,243)
Income Taxes - Def Net						
Distribution	68,243	-	68,243	68,243	-	68,243
Transmission	36,923	-	36,923	9,601	-	9,601
Intangibles	245,642	-	245,642	66,536	-	66,536
General - Situs	32,503	-	32,503	32,503	-	32,503
General - SO	135,318	-	135,318	135,318	-	135,318
General - SG	30,256	-	30,256	30,256	-	30,256
Investment Tax Credit Adj.	-	-	-	-	-	-
Misc Revenue & Expense	-	-	-	-	-	-
Total Operating Expenses:	487,536	709,263	1,196,799	230,537	437,247	667,784
Operating Rev For Return:	(487,536)	1,905,774	1,418,238	(230,537)	1,174,873	944,336
Rate Base:						
Electric Plant In Service		-	-			
Distribution	10,632,306	-	10,632,306	10,632,306	-	10,632,306
Transmission	2,671,547	-	2,671,547	694,649	-	694,649
Intangibles	3,899,761	-	3,899,761	1,056,313	-	1,056,313
General - Situs	840,076	-	840,076	840,076	-	840,076
General - SO	4,103,064	-	4,103,064	1,111,381	-	1,111,381
General - SG	539,155	-	539,155	140,190	-	140,190
Plant Held for Future Use	-	-	-	-	-	-
Total Electric Plant:	22,685,909	-	22,685,909	14,474,916	-	14,474,916
Rate Base Deductions:						
Accum Prov For Deprec						
Distribution	(289,057)	-	(289,057)	(289,057)	-	(289,057)
Transmission	(107,012)	-	(107,012)	(27,825)	-	(27,825)
Intangibles	(1,041,430)	-	(1,041,430)	(282,088)	-	(282,088)
General - Situs	(80,025)	-	(80,025)	(80,025)	-	(80,025)
General - SO	(151,637)	-	(151,637)	(41,073)	-	(41,073)
General - SG	(29,907)	-	(29,907)	(7,776)	-	(7,776)
Accum Prov For Amort	-	-	-	-	-	-
Accum Def Income Tax		-	-	-	-	-
Distribution	(144,681)	-	(144,681)	(144,681)	-	(144,681)
Transmission	(110,615)	-	(110,615)	(28,762)	-	(28,762)
Intangibles	(423,307)	-	(423,307)	(114,660)	-	(114,660)
General - Situs	(107,616)	-	(107,616)	(107,616)	-	(107,616)
General - SO	(198,073)	-	(198,073)	(53,651)	-	(53,651)
General - SG	(51,821)	-	(51,821)	(13,474)	-	(13,474)
Unamortized ITC	-	-	-	-	-	-
Total Rate Base Deductions	(2,735,181)	-	(2,735,181)	(1,190,689)	-	(1,190,689)
Total Rate Base:	19,950,727	-	19,950,727	13,284,227	-	13,284,227
Return on Rate Base	-2.44%		7.11%	-1.74%		7.11%
Return on Equity	-9.60%		9.50%	-8.19%		9.50%
TAX CALCULATION:						
Operating Revenue	(799,861)	2,527,103	1,727,241	(407,823)	1,557,910	1,150,087
Other Deductions	-	-	-	-	-	-
Interest (AFUDC)	-	-	-	-	-	-
Interest	470,444	-	470,444	313,246	-	313,246
Schedule "M" Additions		-	-		-	-
Distribution	182,150	-	182,150	182,150	-	182,150
Transmission	38,764	-	38,764	10,079	-	10,079
Intangibles	425,001	-	425,001	115,118	-	115,118
General - Situs	26,051	-	26,051	26,051	-	26,051
General - SO	110,407	-	110,407	110,407	-	110,407
General - SG	17,072	-	17,072	17,072	-	17,072
Schedule "M" Deductions						
Distribution	459,710	-	459,710	459,710	-	459,710
Transmission	188,940	-	188,940	49,128	-	49,128
Intangibles	1,424,090	-	1,424,090	385,738	-	385,738
General - Situs	158,250	-	158,250	158,250	-	158,250
General - SO	660,780	-	660,780	660,780	-	660,780
General - SG	140,130	-	140,130	140,130	-	140,130
Income Before Tax	(3,502,761)	2,527,103	(975,658)	(2,113,928)	1,557,910	(556,017)
State Income Taxes	(159,025)	114,730	(44,295)	(95,972)	70,729	(25,243)
Taxable Income	(3,343,735)	2,412,372	(931,363)	(2,017,955)	1,487,181	(530,774)
Federal Taxes Before Credits	(702,184)	506,598	(195,586)	(423,771)	312,308	(111,463)
Renewable Energy Tax Credit	-	-	-	-	-	-
Federal Income Taxes	(702,184)	506,598	(195,586)	(423,771)	312,308	(111,463)

PacifiCorp
Oregon General Rate Case - December 2025
2023 Wildfire Mitigation Plan Automatic Adjustment Clause
Incremental Capital Costs Summary
Final Approved in ADV 1529

	Cumulative Project In-Service			Accumulated Reserves		
	Distribution	**Transmission**	**Intangibles**	**Distribution**	**Transmission**	**Intangibles**
UE-399 Compliance In-Rates	9,651,412	11,287,815	-	(9,134)	(8,107)	-
	Distribution	**Transmission**	**Intangibles**	**Distribution**	**Transmission**	**Intangibles**
May-23	11,104,806	3,173,037	3,833,533	(135,205)	(76,328)	(279,780)
Jun-23	11,104,806	3,173,037	3,833,533	(156,224)	(80,886)	(299,444)
Jul-23	11,104,806	3,173,037	3,833,533	(177,243)	(85,444)	(319,109)
Aug-23	11,104,806	3,173,037	3,833,533	(198,262)	(90,002)	(338,773)
Sep-23	11,104,806	3,173,037	3,833,533	(219,282)	(94,559)	(358,438)
Oct-23	11,104,806	3,173,037	3,833,533	(240,301)	(99,117)	(378,102)
2023 WMP AAC Incremental	**1,453,393**	**(8,114,779)**	**3,833,533**	**(231,167)**	**(91,010)**	**(378,102)**

	Depreciation Expense		
	Distribution	**Transmission**	**Intangibles**
UE-399 Compliance In-Rates	219,218	194,568	-
Actual Annual Depreciation	252,230	54,694	235,973
2023 WMP AAC Incremental	**33,012**	**(139,874)**	**235,973**

Depreciation Rate

Distribution	Transmission	Intangibles
2.271%	1.724%	6.156%

PacifiCorp
Oregon General Rate Case - December 2025
2023 Wildfire Mitigation Plan Automatic Adjustment Clause
Total In-Service Capital Costs True-Up

Cumulative Project In-Service

	Distribution	Transmission	Intangibles	Situs	General SO	SG
2023 AAC Currently Approved for Recovery	1,453,393	(8,114,779)	3,833,533	-	-	-
Total Life-time in-service WMP Capital:	**Distribution**	**Transmission**	**Intangibles**	**Situs**	**General SO**	**SG**
May-23	10,632,306	2,671,547	3,899,761	840,076	4,103,064	539,155
Jun-23	10,632,306	2,671,547	3,899,761	840,076	4,103,064	539,155
Jul-23	10,632,306	2,671,547	3,899,761	840,076	4,103,064	539,155
Aug-23	10,632,306	2,671,547	3,899,761	840,076	4,103,064	539,155
Sep-23	10,632,306	2,671,547	3,899,761	840,076	4,103,064	539,155
Oct-23	10,632,306	2,671,547	3,899,761	840,076	4,103,064	539,155
2025 True-Up, based on 2023 AAC rate in effect	9,178,913	10,786,325	66,227	840,076	4,103,064	539,155

Accumulated Reserves

	Distribution	Transmission	Intangibles	Situs	General SO	SG
2023 AAC Currently Approved for Recovery	(231,167)	(91,010)	(378,102)	-	-	-
	Distribution	**Transmission**	**Intangibles**	**Situs**	**General SO**	**SG**
May-23	(188,432)	(87,825)	(941,409)	(71,005)	(54,936)	(22,185)
Jun-23	(208,557)	(91,663)	(961,413)	(72,809)	(74,276)	(23,729)
Jul-23	(228,682)	(95,500)	(981,418)	(74,613)	(93,616)	(25,274)
Aug-23	(248,807)	(99,337)	(1,001,422)	(76,417)	(112,956)	(26,818)
Sep-23	(268,932)	(103,175)	(1,021,426)	(78,221)	(132,297)	(28,362)
Oct-23	(289,057)	(107,012)	(1,041,430)	(80,025)	(151,637)	(29,907)
2025 True-Up, based on 2023 AAC rate in effect	(57,890)	(16,002)	(663,328)	(80,025)	(151,637)	(29,907)
	(289,057)	(107,012)	(1,041,430)	(80,025)	(151,637)	(29,907)

Depreciation Expense

	Distribution	Transmission	Intangibles	Situs	General SO	SG
2023 AAC Currently Approved for Recovery	33,012	(139,874)	235,973	-	-	-
Actual Annual Depreciation	241,498	46,049	240,050	21,648	232,082	18,534
2025 True-Up, based on 2023 AAC rate in effect	208,486	185,924	4,077	21,648	232,082	18,534

Depreciation Rate	Distribution	Transmission	Intangibles	Situs	General SO	SG
	2.271%	1.724%	6.156%	2.577%	5.656%	3.438%

PacifiCorp
Oregon General Rate Case - December 2025
2023 Wildfire Mitigation Plan
Operational & Maintenance Expense Summary
Final Approved in ADV 1529

	2023 WMP O&M Forecast			
Program Category	**Distribution**	**Transmission**	**Software**	**Total**
Risk Modeling and Drivers	-	-	534,400	534,400
Inspection & Correction	777,000	58,000	-	835,000
Vegetation Management	27,060,003	815,715	-	27,875,717
Grid Hardening	300,000	-	-	300,000
Situational Awareness	440,000	-	1,380,000	1,820,000
System Operations	-	-	-	-
Field Operations & Work Practices	2,541,000	-	-	2,541,000
PSPS Program	2,240,000	-	-	2,240,000
Public Safety Partner Coordination	200,000	-	-	200,000
Wildfire Safety & Preparedness Engagement Strategy	1,000,000	-	-	1,000,000
Industry Collaboration	100,000	-	-	100,000
Plan Monitoring & Implementation	800,000	-	-	800,000
Total 2023 WMP O&M Forecast	**35,458,003**	**873,715**	**1,914,400**	**38,246,118**

Less 2023 Wilidfire O&M in Base Rates per UE-399 Settlement	- *
Net 2023 WMP O&M for AAC	**38,246,118**

*Full amount of base period O&M for WMP now to be reflected in AAC.

PacifiCorp
Oregon General Rate Case - December 2025
2023 Wildfire Mitigation Plan Automatic Adjustment Clause
2022 Cost Deferral
Final Approved in ADV 1529

	Total Company			Oregon-Allocated						
		Deferral				Deferral[1]				
	Distribution	Transmission	Software	Beg Balance	Distribution	Transmission	Software	Amortization[3]	Interest[2]	End Balance
Jan-22	989,622	7,419	-	-	989,622	1,983	-		2,949	994,553
Feb-22	1,115,612	29,020	-	994,553	1,115,612	7,755	-		9,256	2,127,176
Mar-22	1,597,843	56,087	-	2,127,176	1,597,843	14,988	-		17,448	3,757,455
Apr-22	1,060,907	34,903	968,035	3,757,455	1,060,907	9,327	268,820		26,329	5,122,839
May-22	2,398,091	105,753	1,732,458	5,122,839	2,398,091	28,261	481,097		39,114	8,069,402
Jun-22	3,216,634	122,647	446,376	8,069,402	3,216,634	32,776	123,957		58,024	11,500,794
Jul-22	4,348,663	30,186	491,285	11,500,794	4,348,663	8,067	136,428		81,762	16,075,714
Aug-22	3,845,250	102,619	459,172	16,075,714	3,845,250	27,423	127,510		107,506	20,183,404
Sep-22	5,706,256	295,064	572,125	20,183,404	5,706,256	78,851	158,877		137,717	26,265,104
Oct-22	3,098,356	102,167	446,376	26,265,104	3,098,356	27,303	123,957		165,875	29,680,596
Nov-22	1,008,100	56,954	818,566	29,680,596	1,008,100	15,220	227,313		180,244	31,111,473
Dec-22	3,459,090	3,565	411,258	31,111,473	3,459,090	953	114,205		195,664	34,881,385
Jan-23				34,881,385	-	-	-		206,643	35,088,028
Feb-23				35,088,028	-	-	-		207,867	35,295,896
Mar-23				35,295,896	-	-	-		209,099	35,504,994
Apr-23				35,504,994	-	-	-		210,338	35,715,332
May-23				35,715,332	-	-	-	(427,930)	195,207	35,482,609
Jun-23				35,482,609	-	-	-	(1,658,228)	148,144	33,972,525
Jul-23				33,972,525	-	-	-	(1,658,228)	141,688	32,455,986
Aug-23				32,455,986	-	-	-	(1,658,228)	135,205	30,932,963
Sep-23				30,932,963	-	-	-	(1,658,228)	128,694	29,403,430
Oct-23				29,403,430	-	-	-	(1,658,228)	122,155	27,867,357
	31,844,426	946,384	6,345,652		31,844,426	252,906	1,762,164	(8,719,067)	2,726,929	

Total Costs Deferred Through Dec-22	33,859,496
Total Interest Accrual Through Dec-22	1,021,889
Total Interest Accrual Through Oct-23	1,705,039
(Less) Estimated Amortization Through Oct-23	(8,719,067)
Net 2022 Balance for Recovery at Oct-23	27,867,357
	-

1 **Allocation Factors (2022)**

2022 Actual SG Factor	26.723%
2022 Actual SO Factor	27.770%

2 **Interest Rate:**

2022 WACC	7.137%
2023 WACC	7.109%
2023 MBTR	5.130%

3 Estimated based on approved 2022 AAC annual collection of $19.8 million

PacifiCorp
Oregon General Rate Case - December 2025
2023 Wildfire Mitigation Plan Automatic Adjustment Clause
Revenue Requirement Variables

Capital Cost and Structure Ordered from Oregon 2023 General Rate Case
Reference UE-399, Final Order 22-491

	Capital Structure	Embedded Cost	Weighted Cost	Pre-Tax Bump-up	Pre-Tax Revenue Requirement
Debt	49.99%	4.72%	2.358%		2.358%
Preferred	0.01%	6.75%	0.001%	132.60%	0.001%
Common	50.00%	9.50%	4.750%	132.60%	6.299%
Total	100.00%		7.109%		8.658%

Merged Effective Tax Rate	24.587%
Pre-Tax Bump-up Factor	132.60%

Franchise Tax and Bad Debt Percentage

Franchise Tax	2.303%	2.383%
Bad Debt Percentage	0.505%	0.522%
Resource Suppliers Tax	0.125%	0.130%
PUC Fee	0.430%	0.445%

2020 Protocol Allocation Factors

Forecasted 2023 SG Factor	26.0018%
Forecasted 2023 SO Factor	27.0866%

Docket No. UE 433
Exhibit PAC/1711
Witness: Sherona L. Cheung

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Sherona L. Cheung

Updated COVID-19 Deferred Costs Amortization

February 2024

PacifiCorp
Oregon General Rate Case - December 2025
COVID-19 Deferral
Updated Amortization Summary

	Amortization
Base Period Amount (below)	-
Pro Forma Amount (below)	5,030,535
Adjustment:	**5,030,535**

		Opening Bal.	Accrual[1]	Amortization	Interest[2,3]	Ending Bal.
2020	March	-	-	-	-	-
	April	-	-	-	-	-
	May	-	-	-	-	-
	June	-	-	-	-	-
	July	-	-	-	-	-
	August	-	-	-	-	-
	September	-	5,982,332	-	4,537	5,986,869
	October	5,986,869	-	-	9,080	5,995,949
	November	5,995,949	-	-	9,094	6,005,042
	December	6,005,042	(3,353,368)	-	6,565	2,658,239
	January	2,658,239	-	-	4,032	2,662,271
	February	2,662,271	-	-	4,038	2,666,308
	March	2,666,308	1,357,694	-	5,073	4,029,076
	April	4,029,076	-	-	6,111	4,035,187
	May	4,035,187	-	-	6,120	4,041,307
	June	4,041,307	5,669,041	-	10,428	9,720,777
	July	9,720,777	-	-	14,743	9,735,520
	August	9,735,520	-	-	14,766	9,750,286
	September	9,750,286	4,123,251	-	17,915	13,891,451
	October	13,891,451	-	-	21,069	13,912,520
	November	13,912,520	-	-	21,101	13,933,621
	December	13,933,621	3,607,863	-	23,869	17,565,352
2022	January	17,565,352	-	-	26,641	17,591,993
	February	17,591,993	-	-	26,681	17,618,674
	March	17,618,674	1,505,515	-	27,863	19,152,052
	April	19,152,052	-	-	29,047	19,181,099
	May	19,181,099	-	-	29,091	19,210,191
	June	19,210,191	3,508,065	-	31,796	22,750,051
	July	22,750,051	-	-	34,504	22,784,555
	August	22,784,555	-	-	34,557	22,819,112
	September	22,819,112	2,389,678	-	36,421	25,245,211
	October	25,245,211	-	-	38,289	25,283,499
	November	25,283,499	-	-	38,347	25,321,846
	December	25,321,846	303,218	-	38,635	25,663,698
2023	January	25,663,698	-	-	109,712	25,773,411
	February	25,773,411	-	-	110,181	25,883,592
	March	25,883,592	453,229	-	111,621	26,448,442
	April	26,448,442	-	419,211	113,963	26,143,194
	May	26,143,194	-	419,211	112,658	25,836,641
	June	25,836,641	180,401	419,211	111,733	25,709,563
	July	25,709,563	-	419,211	110,804	25,401,157
	August	25,401,157	-	419,211	109,486	25,091,431
	September	25,091,431	147,520	419,211	108,477	24,928,218
	October	24,928,218	-	419,211	107,464	24,616,471
	November	24,616,471	-	419,211	106,131	24,303,391
	December	24,303,391	-	419,211	104,793	23,988,973
2024	January	23,988,973	-	419,211	103,449	23,673,210
	February	23,673,210	-	419,211	102,099	23,356,098
	March	23,356,098	-	419,211	100,743	23,037,630

PacifiCorp
Oregon General Rate Case - December 2023
COVID-19 Deferral
Updated Amortization Summary

	Amortization
Base Period Amount (below)	-
Pro Forma Amount (below)	5,030,535
Adjustment:	**5,030,535**

		Opening Bal.	Accrual[1]	Amortization	Interest[2,3]	Ending Bal.
	April	23,037,630	-	419,211	99,382	22,717,801
	May	22,717,801	-	419,211	98,015	22,396,605
	June	22,396,605	-	419,211	96,642	22,074,035
	July	22,074,035	-	419,211	95,263	21,750,086
	August	21,750,086	-	419,211	93,878	21,424,753
	September	21,424,753	-	419,211	92,487	21,098,028
	October	21,098,028	-	419,211	91,090	20,769,907
	November	20,769,907	-	419,211	89,687	20,440,383
	December	20,440,383	-	419,211	88,279	20,109,451
2025	January	20,109,451	-	419,211	86,864	19,777,104
	February	19,777,104	-	419,211	85,443	19,443,336
	March	19,443,336	-	419,211	84,016	19,108,141
	April	19,108,141	-	419,211	82,583	18,771,513
	May	18,771,513	-	419,211	81,144	18,433,446
	June	18,433,446	-	419,211	79,699	18,093,934
	July	18,093,934	-	419,211	78,248	17,752,970
	August	17,752,970	-	419,211	76,790	17,410,549
	September	17,410,549	-	419,211	75,326	17,066,664
	October	17,066,664	-	419,211	73,856	16,721,309
	November	16,721,309	-	419,211	72,380	16,374,477
	December	16,374,477	-	419,211	70,897	16,026,163
2026	January	16,026,163	-	419,211	69,408	15,676,360
	February	15,676,360	-	419,211	67,913	15,325,061
	March	15,325,061	-	419,211	66,411	14,972,260
	April	14,972,260	-	419,211	64,902	14,617,952
	May	14,617,952	-	419,211	63,388	14,262,128
	June	14,262,128	-	419,211	61,867	13,904,784
	July	13,904,784	-	419,211	60,339	13,545,911
	August	13,545,911	-	419,211	58,805	13,185,505
	September	13,185,505	-	419,211	57,264	12,823,558
	October	12,823,558	-	419,211	55,717	12,460,063
	November	12,460,063	-	419,211	54,163	12,095,015
	December	12,095,015	-	419,211	52,602	11,728,406
2027	January	11,728,406	-	419,211	51,035	11,360,230
	February	11,360,230	-	419,211	49,461	10,990,480
	March	10,990,480	-	419,211	47,880	10,619,149
	April	10,619,149	-	419,211	46,293	10,246,230
	May	10,246,230	-	419,211	44,699	9,871,718
	June	9,871,718	-	419,211	43,098	9,495,604
	July	9,495,604	-	419,211	41,490	9,117,883
	August	9,117,883	-	419,211	39,875	8,738,547
	September	8,738,547	-	419,211	38,253	8,357,589
	October	8,357,589	-	419,211	36,625	7,975,002
	November	7,975,002	-	419,211	34,989	7,590,780
	December	7,590,780	-	419,211	33,347	7,204,916
2028	January	7,204,916	-	419,211	31,697	6,817,402
	February	6,817,402	-	419,211	30,040	6,428,231
	March	6,428,231	-	419,211	28,377	6,037,396
	April	6,037,396	-	419,211	26,706	5,644,891
	May	5,644,891	-	419,211	25,028	5,250,708

PacifiCorp
Oregon General Rate Case - December 2023
COVID-19 Deferral
Updated Amortization Summary

	Amortization
Base Period Amount (below)	-
Pro Forma Amount (below)	5,030,535
Adjustment:	**5,030,535**

		Opening Bal.	Accrual[1]	Amortization	Interest[2,3]	Ending Bal.
	June	5,250,708	-	419,211	23,343	4,854,840
	July	4,854,840	-	419,211	21,651	4,457,279
	August	4,457,279	-	419,211	19,951	4,058,018
	September	4,058,018	-	419,211	18,244	3,657,051
	October	3,657,051	-	419,211	16,530	3,254,370
	November	3,254,370	-	419,211	14,808	2,849,967
	December	2,849,967	-	419,211	13,080	2,443,836
2029	January	2,443,836	-	419,211	11,343	2,035,968
	February	2,035,968	-	419,211	9,600	1,626,357
	March	1,626,357	-	419,211	7,849	1,214,994
	April	1,214,994	-	419,211	6,090	801,873
	May	801,873	-	419,211	4,324	386,986
	June	386,986	-	389,473	2,487	0
			Annual Amort =	5,030,535		
			Total Amort =	**31,411,103**		

Note:
1. Incremental accrual represents difference in cumulative total deferred costs as reported in RE-185 through September 2023.
2. 2021 and 2022 Interest rate in deferral period is 2022 Modified Blended Treasury Rate.
3. Interest rate starting January 2023 is MBT Rate per UM-1147, published in January 2023.

PacifiCorp
Oregon General Rate Case - December 2025
COVID-19 Deferral
Amortization Summary As Approved in UE 399

	Amortization
Base Period Amount (below)	-
Pro Forma Amount (below)	5,030,535
Adjustment:	**5,030,535**

		Opening Bal.	Accrual[1]	Amortization	Interest[2,3]	Ending Bal.
2020	March	-	-	-	-	-
	April	-	-	-	-	-
	May	-	-	-	-	-
	June	-	-	-	-	-
	July	-	-	-	-	-
	August	-	-	-	-	-
	September	-	5,982,332	-	4,537	5,986,869
	October	5,986,869	-	-	9,080	5,995,949
	November	5,995,949	-	-	9,094	6,005,042
	December	6,005,042	(3,353,368)	-	6,565	2,658,239
	January	2,658,239	-	-	4,032	2,662,271
	February	2,662,271	-	-	4,038	2,666,308
	March	2,666,308	1,357,694	-	5,073	4,029,076
	April	4,029,076	-	-	6,111	4,035,187
	May	4,035,187	-	-	6,120	4,041,307
	June	4,041,307	5,669,041	-	10,428	9,720,777
	July	9,720,777	-	-	14,743	9,735,520
	August	9,735,520	-	-	14,766	9,750,286
	September	9,750,286	4,123,251	-	17,915	13,891,451
	October	13,891,451	-	-	21,069	13,912,520
	November	13,912,520	-	-	21,101	13,933,621
	December	13,933,621	3,607,863	-	23,869	17,565,352
2022	January	17,565,352	-	-	26,641	17,591,993
	February	17,591,993	-	-	26,681	17,618,674
	March	17,618,674	-	-	26,722	17,645,396
	April	17,645,396	-	-	26,762	17,672,158
	May	17,672,158	-	-	26,803	17,698,961
	June	17,698,961	-	-	26,843	17,725,804
	July	17,725,804	-	-	26,884	17,752,688
	August	17,752,688	-	-	26,925	17,779,613
	September	17,779,613	-	-	26,966	17,806,579
	October	17,806,579	-	-	27,007	17,833,586
	November	17,833,586	-	-	27,048	17,860,633
	December	17,860,633	-	-	27,089	17,887,722
2023	January	17,887,722	-	-	76,470	17,964,192
	February	17,964,192	-	-	76,797	18,040,989
	March	18,040,989	-	-	77,125	18,118,114
	April	18,118,114	-	419,211	78,351	17,777,254
	May	17,777,254	-	419,211	76,894	17,434,936
	June	17,434,936	-	419,211	75,430	17,091,156
	July	17,091,156	-	419,211	73,961	16,745,905
	August	16,745,905	-	419,211	72,485	16,399,179
	September	16,399,179	-	419,211	71,003	16,050,970
	October	16,050,970	-	419,211	69,514	15,701,273
	November	15,701,273	-	419,211	68,019	15,350,081
	December	15,350,081	-	419,211	66,518	14,997,387
2024	January	14,997,387	-	419,211	65,010	14,643,186
	February	14,643,186	-	419,211	63,496	14,287,470

PacifiCorp
Oregon General Rate Case - December 2025
COVID-19 Deferral
Amortization Summary As Approved in UE 399

	Amortization
Base Period Amount (below)	-
Pro Forma Amount (below)	5,030,535
Adjustment:	**5,030,535**

		Opening Bal.	Accrual[1]	Amortization	Interest[2,3]	Ending Bal.
	March	14,287,470	-	419,211	61,975	13,930,234
	April	13,930,234	-	419,211	60,448	13,571,470
	May	13,571,470	-	419,211	58,914	13,211,173
	June	13,211,173	-	419,211	57,374	12,849,336
	July	12,849,336	-	419,211	55,827	12,485,952
	August	12,485,952	-	419,211	54,274	12,121,014
	September	12,121,014	-	419,211	52,713	11,754,516
	October	11,754,516	-	419,211	51,147	11,386,452
	November	11,386,452	-	419,211	49,573	11,016,813
	December	11,016,813	-	419,211	47,993	10,645,595
2025	January	10,645,595	-	419,211	46,406	10,272,790
	February	10,272,790	-	419,211	44,812	9,898,391
	March	9,898,391	-	419,211	43,212	9,522,391
	April	9,522,391	-	419,211	41,604	9,144,784
	May	9,144,784	-	419,211	39,990	8,765,563
	June	8,765,563	-	419,211	38,369	8,384,721
	July	8,384,721	-	419,211	36,741	8,002,250
	August	8,002,250	-	419,211	35,106	7,618,145
	September	7,618,145	-	419,211	33,464	7,232,397
	October	7,232,397	-	419,211	31,815	6,845,001
	November	6,845,001	-	419,211	30,158	6,455,948
	December	6,455,948	-	419,211	28,495	6,065,232
2026	January	6,065,232	-	419,211	26,825	5,672,846
	February	5,672,846	-	419,211	25,147	5,278,782
	March	5,278,782	-	419,211	23,463	4,883,033
	April	4,883,033	-	419,211	21,771	4,485,593
	May	4,485,593	-	419,211	20,072	4,086,454
	June	4,086,454	-	419,211	18,366	3,685,608
	July	3,685,608	-	419,211	16,652	3,283,049
	August	3,283,049	-	419,211	14,931	2,878,769
	September	2,878,769	-	419,211	13,203	2,472,761
	October	2,472,761	-	419,211	11,467	2,065,017
	November	2,065,017	-	419,211	9,724	1,655,529
	December	1,655,529	-	419,211	7,973	1,244,292
2027	January	1,244,292	-	419,211	6,215	831,296
	February	831,296	-	419,211	4,450	416,534
	March	416,534	-	419,211	2,677	(0)
			Annual Amort =	5,030,535		
			Total Amort =	**20,122,139**		

Note:
1. Accrual represents difference in cumulative total deferred costs as reported in each quarterly report filed in RE 185
2. 2021 and 2022 Interest rate in deferral period is 2022 Modified Blended Treasury Rate.
3. Interest rate starting January 2023 is MBT Rate per UM-1147, published in January 2023.

PacifiCorp
Oregon General Rate Case - December 2025
COVID-19 Deferral
Incremental Deferred Costs - UE 399 vs. UE 433

	Dec 2022 ROO SO		27.770%	Dec 2020 ROO SO		28.143%	
	Through 9/30/23 - RE 185 Q3 2023			**Through 12/31/21 - RE 185 Q4 2021**			
	Oregon	Total Company	Allocated/Situs	Oregon	Total Company	Allocated/Situs	Change
Higher bad debt expense due to lower customer collections	5,393,667		5,393,667	1,778,311		1,778,311	3,615,356
Bill payment assistance program	12,944,489		12,944,489	10,819,673		10,819,673	2,124,816
Increased labor and additional facilities to enable social distancing		2,234,464	620,502		2,234,464	628,843	(8,342)
Personal protective equipment, cleaning supplies and contact tracing		2,341,338	650,180		2,182,826	614,311	35,869
Technology costs to allow employees to work from home		503,870	139,923		503,870	141,804	(1,881)
Reduced employee expenses such as travel and trainin		(14,891,103)	(4,135,200)		(13,282,818)	(3,738,173)	(397,027)
CARES Act savings (interest expense on payroll tax deferrals; qualified improvement property tax savings)		(467,025)	(129,691)		(236,231)	(66,482)	(63,209)
Total net costs	18,338,156	(10,278,456)	15,483,870	12,597,984	(8,597,889)	10,178,287	5,305,583
							-
Waived late fees (lower revenue	10,390,330		10,390,330	7,208,289		7,208,289	3,182,042
Foregone reconnection fees	238		238	238		238	-
Grand total			**25,874,438**			**17,386,813**	**8,487,624**
Increase from total approved for amortization in UE 39			**8,487,624**				

PACIFIC POWER.
A DIVISION OF PACIFICORP

825 NE Multnomah Street, Suite 2000
Portland, Oregon 97232

October 30, 2023

VIA ELECTRONIC FILING

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

Re: RE 185—PacifiCorp's COVID-19 Costs, Savings, and Benefits Quarterly Report—Q3 2023

In compliance with the Stipulated Agreement on the Effects of the COVID-19 Pandemic on Energy Utility Customers approved by the Public Utility Commission of Oregon (Commission) in Order No. 20-401, PacifiCorp d/b/a Pacific Power (PacifiCorp or Company) submits this quarterly report itemizing the Company's costs, savings, and benefits resulting from COVID-19. The Company believes it is most meaningful to provide the information for the cumulative period of March 1, 2020 through September 30, 2023, rather than only the quarter ended September 30, 2023.

Bad Debt Expense
The Company is specifically tracking bad debt expense (FERC account 904) through December 31, 2022. The Company calculates a provision for estimated bad debt expense on a monthly basis using historical write-offs (net of recoveries) as a percentage of the respective aging bucket. Those percentages are then applied to current aging buckets. The results of this monthly provision exercise, coupled with actual write-offs and recoveries, represents total bad debt expense. The Company estimates that Oregon bad debt expense is $5,393,667 higher for the period of March 1, 2020 through December 31, 2022, than the amount collected in rates during that same time period due to the impacts of COVID-19. Please refer to Attachment A to this quarterly report for details.

Waived Late Fees
The Company estimates it has waived approximately $10 million of late fees for Oregon customers through September 30, 2022, using the methodology defined in the Stipulated Agreement. The Company resumed collection of late fees on October 1, 2022.

Waived Reconnection Fees
For the period of March 13, 2020 through December 31, 2020, the Company has waived $238 in reconnection fees.

Bill Payment Assistance Funds
PacifiCorp's COVID-19 bill payment assistance program started in the second quarter of 2021. The Company incurred $12,944,489 in costs for this program through September 30, 2023.

Additional Costs and Savings
The Company has identified the following additional costs and savings directly related to the Company's actions to ensure safe working conditions for employees (amounts are through September 30, 2023):

	Total Company	Oregon Allocated
Increased labor and facility costs to enable social distancing	$2,234,464	$620,502
Increased costs for personal protective equipment, cleaning supplies and contact tracing	$2,341,338	$650,180
Increased technology costs to enable employees to work from home	$503,870	$139,923
Reduced employee expenses related to travel and training	($14,891,103)	($4,135,200)
CARES Act savings	($467,025)	($129,691)

It is respectfully requested that all formal data requests regarding this matter be addressed to:

By email (preferred): datarequest@pacificorp.com

By regular mail: Data Request Response Center
PacifiCorp
825 NE Multnomah Street, Suite 2000
Portland, OR 97232

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

Sincerely,

Matthew McVee
Vice President, Regulatory Policy and Operations

Enclosure

PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

January 27, 2022

VIA ELECTRONIC FILING

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

RE: RE 185—PacifiCorp's COVID-19 Costs, Savings, and Benefits Quarterly Report— Q4 2021

In compliance with the Stipulated Agreement on the Effects of the COVID-19 Pandemic on Energy Utility Customers approved by the Public Utility Commission of Oregon (Commission) in Order No. 20-401, PacifiCorp d/b/a Pacific Power (PacifiCorp or Company) submits this quarterly report itemizing the Company's costs, savings, and benefits resulting from COVID-19. The Company believes it is most meaningful to provide the information for the cumulative period of March 1, 2020 through December 31, 2021, rather than only the quarter ended December 31, 2021.

Bad Debt Expense
The Company is specifically tracking bad debt expense (FERC account 904). The Company calculates a provision for estimated bad debt expense on a monthly basis using historical write-offs (net of recoveries) as a percentage of the respective aging bucket. Those percentages are then applied to current aging buckets. The results of this monthly provision exercise, coupled with actual write-offs and recoveries, represents total bad debt expense. The Company estimates that Oregon bad debt expense is $1,778,311 higher for the period of March 1, 2020 through December 31, 2021, than the amount collected in rates during that same time period due to the impacts of COVID-19. Please refer to Attachment A to this quarterly report for details.

Waived Late Fees
The Company estimates it has waived approximately $7 million of late fees for Oregon customers through December 31, 2021 using the methodology defined in the Stipulated Agreement.

Waived Reconnection Fees
For the period of March 13, 2020 through December 31, 2020, the Company has waived $238 in reconnection fees for Oregon Customers.

Bill Payment Assistance Funds
PacifiCorp's COVID-19 bill payment assistance program started in the second quarter of 2021. The Company incurred $10,819,673 in costs for this program through December 31, 2021.

Additional Costs and Savings
The Company has identified the following additional costs and savings directly related to the Company's actions to ensure safe working conditions for employees (amounts are through December 31, 2021):

	Total Company	Oregon Allocated
Increased labor and facility costs to enable social distancing	$2,234,464	$628,843
Increased labor and facility costs to enable social distancing	$2,182,826	$614,311
Increased technology costs to enable employees to work from home	$503,870	$141,804
Reduced employee expenses related to travel and training	($13,282,818)	($3,738,173)
CARES Act savings	($236,231)	($66,482)

It is respectfully requested that all formal data requests regarding this matter be addressed to:

By email (preferred): datarequest@pacificorp.com

By regular mail: Data Request Response Center
PacifiCorp
825 NE Multnomah Street, Suite 2000
Portland, OR 97232

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

Sincerely,

Shelley McCoy

Shelley McCoy
Director, Regulation

Enclosure

Docket No. UE 433
Exhibit PAC/1800
Witness: Anna DeMers

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Anna DeMers

February 2024

TABLE OF CONTENTS

ATTACHED EXHIBIT

I. INTRODUCTION AND QUALIFICATIONS

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

A. My name is Anna DeMers, and my business address is 315 W. 27th Street, Cheyenne, Wyoming, 82001. I am a Senior Customer Regulatory Specialist for PacifiCorp.

Q. Please describe your education and professional experience.

A. I hold a Bachelor of Science degree in civil engineering with a minor in Spanish language and literature, and a Master of Science degree in environmental engineering from the University of Wyoming. Before joining PacifiCorp in January of 2023, I worked for the Wyoming Office of Consumer Advocate (OCA) and had previously held engineering and environmental science positions for private industry and state government.

Q. Have you testified in previous regulatory proceedings?

A. Yes, during my time working for the OCA I served as an expert witness and represented the interests of Wyoming citizens in cases involving regulated industries before the Wyoming Public Service Commission. However, I have not previously testified on behalf of PacifiCorp, or before the Public Utility Commission of Oregon (Commission).

Q. Have you filed any exhibits to support your testimony?

A. Yes. Exhibit PAC/1801 shows the calculation of the Capacity Reservation Charge and the Excess Demand Charge. Workpapers showing how these charges were calculated are included with the workpapers of Company witness Robert M. Meredith. Modifications to tariff language proposed in my testimony are included in

Exhibit PAC/1901 of Company witness Meredith's testimony, and include changes to Rule 1, Rule 13, and Schedule 300.

II. PURPOSE OF TESTIMONY

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

A. The primary purpose of my testimony is to introduce and support several policies PacifiCorp proposes to implement that would affect very large customers. These proposed policies include changes to how the Company manages system capacity and load requests, including creating a Capacity Reservation Charge and an Excess Demand Charge. I also introduce other proposed modifications to the tariff in my testimony including an extension to the period during which large customers are eligible for Line Extension Refunds (Refunds), a change to the Company's definition of Extension Limits, a change in the timing when Line Extension Advances (Advances) are paid by large customers, and new defined terms that the Company proposes to add to its tariffs.

Q. What characteristics is the Company using to define very large customers in the context of your testimony?

A. Proposed policy changes discussed in my testimony are intended to apply to customers with loads greater than 25,000 kilowatts (kW), unless otherwise stated. As a result of a recent Company filing that was approved by the Commission,[1] this definition of very large customers is used to differentiate between customers when determining Line Extension Allowance amounts in PacifiCorp's Oregon Rule 13 – Line Extensions.

[1] Order No. 23-472 issued on December 12, 2023, in Docket No. UE 424.

Q. Why is it justifiable to create policies that only affect very large customers?

A. Very large customers are distinct from other customers in significant ways. Most relevant to this testimony, the load requests of very large customers are extremely impactful to the Company's long-term transmission and generation planning. Transmission and generation investments necessary to serve very large customers present sizeable stranded asset risks on a per-customer basis. The policies the Company is proposing in this testimony would provide a just and reasonable way to help limit the risk very large customers pose to other customers by ensuring that very large customers are allocated all costs associated with Reserved Capacity.

III. CAPACITY RESERVATION CHARGE

Q. What is Reserved Capacity?

A. Reserved Capacity is the capacity reserved for a new or expanding customer, as specified in written agreements.

Customers provide load requirement estimates when requesting service from the Company. Sometimes a customer's total load will fully materialize shortly after energization—effectively coming online all at once. However, it is more common for very large customers to plan to incrementally increase their load over time, and load requests provided to the Company frequently include planned load ramps.

When the Company receives a service request from a very large customer, representatives from the Company meet with the customer to ensure that the customer's load estimate is realistic, and to discuss capacity availability at the requested grid interconnection point. These conversations ultimately lead to an agreement between the Company and customer that specifies the Customer's Reserved Capacity.

Q. What are the impacts of Reserved Capacity?

A. Load projections provided to the Company when a customer requests service are incorporated into the Company's forecasts and used to plan system transmission and generation investments. Investments to expand system capacity are lumpy and are often made well in advance of additional load coming online—long before there is offsetting revenue from rates to recover the cost of these investments. Additionally, Reserved Capacity affects the load interconnection queue and may delay or prevent other shovel-ready customers from being able to receive service. It also affects the sizing of line extension facilities and may cause subsequent customers to trigger network upgrades, increasing line extension costs for the customer requesting service as well as possibly also directly increasing the cost for subsequent customers to connect to PacifiCorp's system.

In a recent proceeding, the Company proposed and the Commission approved to limit the Line Extension Allowance for customers requiring more than 25,000 kW to the cost of metering necessary to measure customer energy usage.[2] This change directly allocated some of the costs of Reserved Capacity to very large customers and has greatly mitigated the risks to other customers of stranded line extension costs directly caused by very large customers. However, other risks of Reserved Capacity persist, including the risk to other customers of stranded upstream transmission and generation investments made to serve very large customers.

[2] Order No. 23-472 issued on December 12, 2023, in Docket No. UE 424.

Q. How is Reserved Capacity treated under the existing tariff?

A. PacifiCorp's Oregon Rule 13 – Line Extensions, Section III.D, obligates the Company to reserve capacity for customers at least equal to the maximum recorded and billed consumer demand in the most recent 36 months. Under the existing tariff, customers that receive retail electric service from the Company are billed based on their actual energy usage. Customers are not charged for unused capacity on PacifiCorp's system that is reserved for them (Excess Reserved Capacity).

Q. Why does the Company believe the existing mechanisms to manage Reserved Capacity in the tariff are inadequate?

A. Load projections provided to the Company at the time that line extensions are requested frequently overestimate the load customers will ultimately use, particularly for very large customers with load ramping schedules that forecast the customer's load requirements years into the future. The existing tariff does not provide a means to recover the costs of Excess Reserved Capacity from customers in the 36-month interim before Reserved Capacity may be reduced, or to allow customers to choose to pay for the continued availability of Reserved Capacity after the 36-month period. Therefore, customers with loads less than their Reserved Capacity are not accurately allocated the costs that they create, but also do not have the option to preserve capacity they have requested if business or operational delays prevent them from ramping according to their original estimated load projections.

More robust tools are needed to manage Excess Reserved Capacity, and to directly allocate the costs of Excess Reserved Capacity to individual customers that create these costs, than what the tariff currently provides. The tariff changes and charges proposed by the Company will increase the ability of the Company and customers to efficiently manage Reserved Capacity.

Q. What is the proposed Capacity Reservation Charge and how would it be calculated?

A. The proposed Capacity Reservation Charge is a charge that would be applied to all kilowatts of Excess Reserved Capacity as part of the monthly bills of affected customers. The proposed Capacity Reservation Charge is $4.91 per kW. The Capacity Reservation Charge would be the same amount for all applicable customers and would be set to recover the Federal Energy Regulatory Commission (FERC) transmission function revenue requirement plus 11.5 percent of fixed generation costs.

Q. Why does the Company propose setting the Capacity Reservation Charge to recover the FERC transmission function revenue requirement?

A. The Company proposes charging customers the FERC transmission function revenue requirement because transmission facilities are built to meet peak demand. The Company will incur the cost of building facilities capable of transporting energy to fully serve the customer's Reserved Capacity whether the customer uses electricity or not.

Q. Why is the Company proposing to recover 11.5 percent of the cost of fixed generation through the Capacity Reservation Charge?

A. The Company incorporates Reserved Capacity into its load forecasts used to plan its acquisition of generation assets. Costs, like the cost of building Company-owned generation facilities, are incurred as a direct result of Reserved Capacity and the Company's long-term load forecasts.

The Company's proposal to charge customers 11.5 percent of fixed generation costs is based on the Company's planning reserve margin. The Company is required to have sufficient electricity available to serve unexpected changes in energy supply and demand such as fluctuations in energy usage, and so it plans for a 13 percent planning reserve margin. Therefore, the Company plans to have capacity available to serve 113 percent of the annual peak load it has forecasted. Recovering the cost of planning uncertainty from customers with Excess Reserved Capacity is reasonable, because the Company has forecast for customer loads in its planning and those loads have not shown up. Thirteen percent of 113 percent is 11.5 percent.

Q. Which customers would be required to pay the Capacity Reservation Charge?

A. Customers with total expected loads exceeding 25,000 kW would be required to pay the Capacity Reservation Charge for Excess Reserved Capacity. As explained earlier in my testimony, very large customers acutely impact Company transmission and generation facility planning. Additionally, both because of the scale of their operations and the lead times required to build line extension and other electric infrastructure to serve them, very large customers frequently forecast their energy needs years into the future and are likely to require Reserved Capacity. Forecasting energy needs years in advance reduces the accuracy of load forecasts. Obviously, as a forecast is made further out in time, there are more factors that may affect a customer's ultimate energy needs. The long lead times on building Company infrastructure also influence customers to overestimate their load requirements so that they will not be forced to wait years for additional capacity if their initial forecasts are too conservative.

Additionally, limiting the requirement to pay this charge to very large customers provides the ancillary benefit of simplifying billing and implementation of this policy, while still greatly benefiting and improving the efficiency of PacifiCorp's system as very large customers have the greatest per-customer impact on system planning.

Permanently opted-out direct access customers would not be subject to the Capacity Reservation Charge, because the Company does not plan for these customers in its forecasts or purchase transmission rights to serve them.

Q. Is the Company proposing any limitations on the ability of customers to change Reserved Capacity after energization?

A. Yes. The Company has included proposed tariff language that would limit how quickly customers may reduce Reserved Capacity. As proposed by the Company, each customer would be permitted to reduce Reserved Capacity by up to 10 percent of the customer's total load per year or 50 megawatts per year, whichever is smaller, or by a larger amount if mutually agreed upon by the customer and the Company. Limiting how quickly a customer may reduce Reserved Capacity provides the Company time to adjust system investment planning in response to changes in requested customer load, and encourages customers to provide accurate load requests when requesting service. The Company also included proposed tariff language stating requests to increase Reserved Capacity may be considered at the Company's discretion.

Q. Will any other customers be affected by the Company's proposal to create a Capacity Reservation Charge?

A. The Company has the right to revoke unused capacity under the existing tariff, and smaller customers may wish to maintain flexibility to pay to keep Reserved Capacity in lieu of the Company exercising this right. Therefore, the Company proposes that Customers requiring more than 1,000 kW but less than 25,000 kW should have the option to pay the Capacity Reservation Charge to maintain Excess Reserved Capacity on PacifiCorp's system.

Q. Does the Company plan to treat existing and new customers the same when calculating the Capacity Reservation Charge?

A. No. Excess Reserved Capacity would be calculated differently for existing and new customers. For customers that signed contracts with the Company prior to January 1, 2025, Excess Reserved Capacity would be calculated based on the maximum recorded and billed consumer demand in the most recent 36 months. For new customers, it would be based on the maximum recorded and billed consumer demand in the most recent 12 months.

Q. Why would there be different treatment of legacy and non-legacy customers under contract load requests?

A. Existing customers entered into service agreements with the Company with the understanding that they would have 36 months to use Reserved Capacity before it would be reclaimed by the Company. The Company proposes to only reduce this time limit to 12 months for new customers to reduce overplanning and overbuilding by the

Company, while continuing to honor the tariff terms that were in place to preserve Reserved Capacity when existing customers signed service agreements.

Q. Does the Company anticipate additional benefits from creating the Capacity Reservation Charge?

A. Yes. Creating a charge to allocate the costs of Excess Reserved Capacity to individual customers will provide an accurate price signal which may encourage customers to improve the accuracy of load requests provided to the Company, or to relinquish unneeded Excess Reserved Capacity that they hold. These actions on the part of customers could reduce the Company's system costs and could free up unused capacity so that the Company can provide service to new customers which it would otherwise be unable to immediately serve.

Q. When would the Company begin charging customers a Capacity Reservation Charge?

A. The Company believes it is reasonable to provide at least six months for existing customers to request to reduce their Reserved Capacity before charging customers for Excess Reserved Capacity. Therefore, the Company proposes to begin charging customers a Capacity Reservation Charge on July 1, 2025, which is six months after the expected effective date of this general rate case.

IV. EXCESS DEMAND CHARGE

Q. Why is the Company proposing to create an Excess Demand Charge?

A. System costs are minimized when the Company has accurate load forecast information. The Capacity Reservation Charge may encourage customers not to overestimate their load requirements. Conversely, the creation of an Excess Demand

Charge would ensure that customers do not underestimate their needed load and operate their facilities within the bounds of their load request.

Q. How would the Excess Demand Charge be calculated?

A. As explained above, the Company plans to charge customers an Excess Demand Charge when a customer's load exceeds forecasts stipulated in written agreements. Under these circumstances, the Company would not be able to anticipate the need for additional capacity and additional transmission rights. Depending on when a customer's energy use exceeds their Reserved Capacity, the Company may incur higher power costs. More dire outcomes may result when load forecasts are exceeded under extreme circumstances, and the reliability of PacifiCorp's system could be compromised.

Because of the negative outcomes possible when system load exceeds the Company's forecast, the Company proposes to set the Excess Demand Charge as a multiple of the Capacity Reservation Charge. The Company is proposing an Excess Demand Charge of $19.64 per kW, which is equal to four times the Capacity Reservation Charge.

Q. Which customers would be required to pay an Excess Demand Charge?

A. Customers required to pay a Capacity Reservation Charge would also be subject to an Excess Demand Charge. Customers requiring more than 25,000 kW would automatically be billed this charge when their maximum demand exceeds their Reserved Capacity. Permanently opted-out direct access customers would not be subject to an Excess Demand Charge.

Q. When would the Company begin charging customers an Excess Demand Charge?

A. The Company proposes to begin charging customers an Excess Demand Charge on July 1, 2025, to provide time for customers to adjust their operation and business practices to curb demand which exceeds the customer's Reserved Capacity.

V. REFUND ELIGIBILITY

Q. What are Line Extension Refunds?

A. A Line Extension Refund is a pass-through between customers which is collected by the Company. Line Extension Refunds are used to reimburse initial customers who paid for the cost of line extension facilities with an Advance when those line extension facilities benefit subsequent customers. In Oregon Rule 13, Line Extension Refunds are limited to three customers during the first five years after construction for all eligible customers.

Q. Please explain the Company's proposed changes to Refund eligibility for very large customers.

A. Interested Parties to docket UE 424 suggested that Line Extension Refund limitations in the Company's tariff should be reduced for very large customers. Unlike other nonresidential customers requesting distribution-voltage service, new line extension applicants requiring more than 25,000 kW are no longer eligible for a Line Extension Allowance equal to a multiple of their revenue following the Commission's approval of the Company's proposal in docket UE 424. Consequently, the potential impact of Line Extension Refund policy on these customers is more significant than it is on smaller customers because very large customers pay a larger Advance. Additionally, the five-year limitation on Refunds is not appropriate for very large customers since it sometimes takes several years to build line extension facilities to serve subsequent customers with very large load requests that may owe a Refund to the initial customer. Therefore, the Company proposes to increase the window during which very large customers are eligible for Refunds from five years to 10 years.

VI. ADDITIONAL TARIFF CHANGES

Q. Is the Company proposing any additional changes to tariff rules that you are presenting in your testimony?

A. Yes. The Company is proposing to add language to Rule 13 to formalize the Company's ability to consider whether a load request is speculative when evaluating the customer interconnection queue, and to change the definition of Transmission Voltage in the tariff to service at or above 46,000 volts. The Company is also proposing to eliminate language in the tariff which permits customers requiring more than 1,000 kW to pay only half of the Line Extension Advance prior to construction.

Q. Why is the Company proposing to add language to Rule 13 to address treatment of speculative load requests?

A. The Company is receiving a number of very large load requests that it considers speculative, and that may not produce sufficient revenues to justify Company investments made to serve them. Examples of speculative load requests received by the Company include requests for cryptocurrency mining, for large loads to serve novel technologies, and load requests for data center capacity to be subleased without contracted recipients for energy at the time of the line extension request.

The Extension Limits definition in the Oregon Rule 13 – Line Extensions states that the provisions of the Rule do not apply to projects that will not have sufficient revenues to cover ongoing costs, but it doesn't clarify what is meant by sufficient revenues. In other states that PacifiCorp serves, the tariff clarifies that the Company may make special considerations for handling speculative load requests. The Company believes adding similar language to Oregon's tariff is appropriate to clarify what is meant by sufficient revenues and that the Company may consider the risk of stranded investments that customers present to the system when evaluating customer line extension treatment and the load request queue.

Q. Is the Company proposing to add any tariff language addressing load request limitations that is specific to the load request queue?

A. Yes. The Company proposes to add language to Section III.D of Oregon Rule 13 – Line Extensions to establish tariff limitations on load requests that the Company will consider including in the load request queue. This proposed language explains to customers that the Company considers available system capacity at requested interconnection points when evaluating load requests, and that requests may be denied if capacity is not available. This provision protects the Company and customers from the need to greatly invest in expanding capacity at highly congested interconnection points, and may encourage customers to request service at site locations with available existing capacity to increase system planning efficiency. The proposed language in this section also creates additional restrictions on load requests that are five years in the future. Generally, the further out the planning horizon, the more speculative planning for individual customers becomes.

Q. Why is the Company proposing to reduce the threshold for what is considered transmission voltage in the tariff?

A. The voltage considered Transmission Voltage varies across PacifiCorp's six-state service territory as a legacy of historical local grid operating conditions. The Company proposes changing the voltage defined as Transmission Voltage in Rule 1 and subsection III.A of Rule 13 from 57,000 volts to 46,000 volts to ensure consistency in the Company's tariffs in the different jurisdictions where it operates. This change to the Oregon tariff definition is for clarification and consistency only and is not anticipated to result in any changes to actual operation or to customer bills.

Q. Please explain the proposed tariff change to the Line Extension Advances of customers requiring more than 1,000 kW.

A. Under the existing tariff, all customers except customers requiring more than 1,000 kW are required to pay the full Line Extension Advance prior to construction. Customers requiring more than 1,000 kW are required to pay 50 percent of the Advance when the line extension agreement is executed, and 50 percent upon completion of construction.

With larger customer loads, it becomes more costly to provide service to that customer and the risk of stranded asset creation associated with beginning construction on line extension facilities to serve that customer is greater. Existing tariff provisions that create less strict Line Extension Advance payment timelines for customers requiring 1,000 kW or greater compared to smaller customers do not reflect the relative risk that large customers present when the Company begins building line extension facilities to serve them compared to smaller customers.

Therefore, the Company proposes to require all customers to pay the full Line Extension Advance prior to construction, as a later payment schedule for customers requiring 1,000 kW or greater is not justifiable.

VII. CONCLUSION

Q. Please summarize your testimony.

A. Creating a Capacity Reservation Charge and an Excess Demand Charge will improve system planning by incentivizing very large customers to provide accurate load forecasts, and to relinquish unused capacity. Additionally, these charges will improve fixed cost allocation by appropriately charging very large customers for the costs of reserving capacity. Creating a Capacity Reservation Charge and an Excess Demand Charge is just, reasonable, and in the public interest. For these reasons, the Company requests the Commission to approve the implementation of these charges, in addition to other refinements to the Company's tariff explained in this testimony.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 433
Exhibit PAC/1801
Witness: Anna DeMers

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Anna DeMers

Proposed Capacity Reservation Charge and Excess Demand Charge

February 2024

Pacific Power
State of Oregon
Calculation of Proposed Capacity Reservation Charge and Excess Demand Charge
Based on Proposed Revenues for Primary and Transmission Customers 1MW and Over

Transmission & Ancillary Services, revenues for proposed rates	$24,347,442
Base Generation (Schedule 200), revenues for proposed rates	$90,977,830
11.5% of Base Generation revenues	$10,462,450
Total for Calculation	$34,809,892
kW Billing Demand	7,085,816
Capacity Reservation Charge ($/kW)	**$4.91**
Excess Demand Charge (4 x Capacity Reservation Charge)	**$19.64**

Docket No. UE 433
Exhibit PAC/1900
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Robert M. Meredith

February 2024

TABLE OF CONTENTS

ATTACHED EXHIBITS

Exhibit PAC/1914—Residential Schedule 6 Time-of-Use Pilot Program Evaluation

Exhibit PAC/1915—Non-Residential Schedule 29 Time-of-Use Pilot Program Evaluation

Exhibit PAC/1916—Calculation of Proposed Time-of-Use On-Peak Surcharges and Off-Peak Credits

Exhibit PAC/1917—Cost of Eliminating Payment Fees

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 19 years in various roles of increasing responsibility in the Customer Service, Regulation, and Integrated Resource Planning departments. I have over 13 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 current position.

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 Public Utility Commission of Oregon's (Commission) rules under OAR 860-038-0200. I am sponsoring the Company's

Oregon electric tariff schedules submitted for approval in this filing. Exhibit PAC/1901 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 the Insurance Cost Adjustment, the Catastrophic Fire Fund Adjustment, changes to the Wildfire Mitigation Plan Cost Recovery Adjustment, and the rebalancing of the Rate Mitigation Adjustment (RMA), is $322.3 million or 17.9 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, 2025, where no customer rate class will see a rate increase more than 22.4 percent.

For rate design, the Company largely proposes applying the price change on an equal percentage basis across prices for each class for all schedules, except residential. For residential customers, the Company proposes increasing the single-family basic charge from $11 to $16 per month and the multi-family basic charge from $8 to $9.

As of the time of this filing, the Company has concluded its three-year pilot periods for three pilots it introduced in docket UE 374 (2021 Rate Case): 1) Interruptible Service Schedule 218; 2) Residential Time-of-Use Schedule 6; and 3) Non-Residential Time-of-Use Schedule 29. I address each of these pilots and present the Company's proposal to improve and consolidate its time-of-use options.

For large customers with load sizes greater than 25,000 kilowatts (kW) who did not receive a Line Extension Allowance more than the cost of metering, the Company proposes a Customer-Funded Substation Credit.

Finally, I support the Company's proposal to eliminate credit/debit card payment and pay station fees.

III. UNBUNDLED CLASS REVENUE REQUIREMENTS

Q. Please identify Exhibit PAC/1902 and explain what it shows.

A. Exhibit PAC/1902 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,

[1] *See* OAR 860-038-0200.

revenues and expenses are from PacifiCorp's Oregon Results of Operations Report, as prepared under the direction of Company Sherona L. Cheung. The application of PacifiCorp's proposed rate increase is shown on page 2 of Exhibit PAC/1902.

Q. Please identify Exhibit PAC/1903 and explain what it shows.

A. Page 1 of Exhibit PAC/1903 is the summary page from PacifiCorp's December 2025 Functionalized Oregon Results of Operations Report (Functionalized Oregon Results of Operations Report) and is the basis for the unbundled revenue requirement in Exhibit PAC/1902. It separates the results of operations into the unbundled categories identified above.

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 page 2 through 38 of Exhibit PAC/1903. The functionalization procedures in this case are consistent with those approved in Order No. 01-787 and implemented in Advice No. 01-020. Functional factors employed in the development of these results are provided in Exhibit PAC/1904.

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/1905. 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/1906.

A. Exhibit PAC/1906 contains a summary from PacifiCorp's State of Oregon December 2024 Marginal Cost Study (Marginal Cost Study). The Marginal Cost Study is described in more detail later in my testimony.

Q. Please identify Exhibit PAC/1907 and explain what it shows.

A. Page 1 of Exhibit PAC/1907 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 11. Lines 13 through 24 show each class share of total marginal costs for each function as well as each class share of revenue and MWh. Lines 27 through 39 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 40.60 percent of generation marginal costs and is assigned 40.60 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 41 through 48 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/1907.

A. Pages 2 and 3 of Exhibit PAC/1907 provides a reconciliation between Operating Revenues and Target Revenue Requirement, as shown on page 1 of this exhibit, with those shown in Exhibits PAC/1902 and PAC/1903. Not all customer classes are included in the Marginal Cost Study. Page 2 of Exhibit PAC/1907 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/1908. 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/1908 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. With the exception of the methodology for calculating marginal generation costs, this study is similar to the cost-of-service study the Company presented in docket UE 399 (2023 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 12 of Exhibit PAC/1908.

Q. Please describe the marginal cost summary tables included in pages 13 through 20 of Exhibit PAC/1908.

A. Tables 1 and 2 of Exhibit PAC/1908 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, 2025, test period. This information is used to calculate the annual long-run marginal costs by class shown at the bottom of Table 3.

Q. What changes does the Company propose for marginal generation costs?

A. Before this rate case, the Company based its marginal generation costs on the equivalent Peaker method that examined the cost characteristics of gas-fired generators. In the 2023 Rate Case, the Company received feedback from parties that relying upon fossil fuel resources for marginal generation costs is not appropriate in light of the transition to renewables.[2] The Company proposes that the marginal generation costs in this study be based upon forecast costs of a storage resource and

[2] See pages 3 through 7 of Alliance of Western Electric Consumers Witness Mr. Lance Kaufman's direct testimony in Docket No. UE 399, and pages 3 through 11 of Commission Staff Witness Mr. Curtis Dlouhy.

wholesale market purchases—specifically the cost of a four-hour Lithium-Ion battery from the Company's 2023 Integrated Resource Plan and the cost of a flat market purchase from the Mid-Columbia (Mid-C) hub from PacifiCorp's most recent Oregon avoided cost calculations. Marginal generation capacity costs are determined using the cost per kW-Year of a Lithium-Ion battery accounting for the battery's 77 percent capacity contribution. The forecast energy benefit from the battery is then deducted from this cost to arrive at the marginal generation capacity cost. Generation energy costs are calculated using forecast market prices from the Mid-C hub that are net of a capacity credit to recognize that a firm market purchase can be relied upon to meet the Company's peak load requirements. Marginal generation capacity and energy costs are summarized on Table 4 of Exhibit PAC/1908.

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/1908.

Q. Please provide a general overview of how marginal distribution costs are determined.

A. Table 6 of Exhibit PAC/1908 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 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 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 12 of Exhibit PAC/1908.

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 Advanced 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.”[3] 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/1909 summarize the functionalized results of the cost-of-service study in column (4). This summary is provided at the level used to

[4] OAR 860-038-0240(3)(b).

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 NPC.

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/1909 summarize 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. Please explain the System Usage costs shown in exhibit PAC/1909 and how those costs are proposed to be recovered in rates.

A. In Order No. 12-500, the Commission directed the Company to develop a volumetric rate element for franchise fees that could be avoided by customers taking direct access. Consistent with past treatment, the amounts shown as System Usage costs in

Exhibit PAC/1909 are a portion of the Oregon Franchise Tax and Oregon Energy Supplier Assessment from FERC Account 408 in the results of operations.[4] The System Usage costs have been calculated as the portion of the franchise and energy supplier taxes associated with revenues not paid by direct access customers: NPC and transmission and ancillary services. A separate volumetric rate element is used to recover these costs, which is not paid by direct access customers.

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 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 in column (5) on pages 1 and 2 of Exhibit PAC/1909. 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/1909. A direct comparison to the target functionalized revenues shown in

[5] The Oregon Energy Supplier Assessment is a fee paid to the Oregon Department of Energy under ORS 469.421(8). While this treatment for this assessment was not reflected in Order No. 12-500, the Company has included it in the System Usage Charge because it is assessed in the same manner (a percent of revenue) as franchise taxes in FERC Account 408. The Company is therefore using parallel treatment.

column (6) 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/1909.

Q. Have you prepared an exhibit showing the estimated effects of the prices proposed in this general rate case?

A. Yes. The first three pages of Exhibit PAC/1910 show the estimated effect of the Company's proposed prices. It contains three summary tables. Table 1910-1 shows the effect of the proposed prices by delivery service rate schedule for the proposed rate increase on January 1, 2025, of approximately $322.3 million which includes approximately $66.0 million for the Insurance Cost Adjustment (base and deferred), $77.7 million for the Catastrophic Fire Fund Adjustment, $21.2 million additional for the Wildfire Mitigation Plan Cost Recovery Adjustment, minus $0.4 million for the impact of the RMA rebalancing. 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) and the RMA.

The adder columns in Table 1910-1 show revenues from adjustment tariff schedules (Schedules 80, 94, 96, 97, 190, 192, 193, 194, 198, 203, 204, 206, 207, and 299). Proposed new adjustment schedules and proposed changes to adjustment schedules are included in the Proposed adder column only. The adder revenue is added to base revenue to calculate net revenue including adjustment schedules. Table 1910-2 shows the calculation of the adjustment revenue included in the adder columns in Table 1910-1. These tables exclude the effects of pass-through adjustment schedules for Low Income Bill Payment Assistance Charge (Schedule 91), the Low-Income Discount Cost Recovery Adjustment (Schedule 92), 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 1910-3 shows the rates for each of the adjustment schedules.

Beginning on page 4 of Exhibit PAC/1910 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/1910 show the expected rate increases for January 1, 2025, 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 is 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, including the impact of proposed new and updated adjustment schedules, for the major rate schedule classes.

TABLE 1

Residential Schedule 4	21.6%
General Service	
Schedule 23/723 (0-30kW)	22.4%
Schedule 28/728 (31-200kW)	10.4%
Schedule 30/730 (201-999kW)	11.3%
Large General Service Schedules 47/747, 48/748 (≥1,000kW)	14.1%
Agricultural Pumping Service Schedule 41/741	22.4%
Lighting Schedules	4.5%
Overall	17.9%

Under the Company's proposal, the rate change that takes effect January 1, 2025, will result in no customer rate schedule class receiving an increase greater than 22.4 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 2023 forecast test period from the Company's 2023 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 2025 test period of this case. The present RMA rates result in RMA charges that exceed RMA credits by $0.4 million for the 2025 test period loads (see Exhibit PAC/1910, Table 1910-2, Column 17, Row 18). Consistent with previous RMA revisions, the proposed RMA rates have been designed to be revenue neutral for the 2025 test period. As a result of this realignment, the proposed net rate increase in this case is lower by $0.4 million (Exhibit PAC/1910, Table 1910-1).

Q. Has the RMA required rebalancing in previous general rate cases?

A. Yes. For example, in the 2023 Rate Case the RMA required a rebalancing adjustment of $4.5 million.

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/1910, Table 1910-2, columns (17) and (18). Present and proposed RMA rates are shown in Exhibit PAC/1910, Table 1910-3, columns (18) and (19).

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. As a result, the Company has limited RMA charges and credits as much as possible. The Company proposes to move RMA rates closer to zero for all rate schedules except for General Service Schedule 23/723 and Agricultural Pumping Service Schedule 41/741. Increases to the RMA credit were necessary for these classes to minimize the rate impact and cap their net increase at 22.4 percent which is about 25 percent higher than the overall proposed net percentage increase of 17.9 percent.

For Large General Service Schedules 47/747 and 48/748 and Residential Schedule 4, the Company proposes eliminating the RMA. The proposed January 1 net increase for Schedules 47/747 and 48/748 is 14.1 percent. The proposed January 1 net increase for Schedule 4 is 21.6 percent.

For the Lighting Schedules 15, 51, 53, and 54, the Company proposes decreasing the very high RMA surcharge levels currently in rates for these customers while still giving them a price increase. Absent the RMA, the lighting schedules would receive a price decrease. In light of the overall price increase, the Company proposes a January 1 net increase for the lighting class of 4.5 percent, which is about 25 percent of the overall increase.

Finally, for General Service Schedules 28/728, and 30/730, the Company proposes setting their RMA surcharges at roughly half their present level which results in a net increase of 10.4 percent and 11.3 percent, respectively.

Overall, the Company believes that these proposals result in just and reasonable rates and will minimize rate impacts while reducing subsidization through the RMA.

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 2025.

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 Company witness 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 2023. 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/1909 contain historical and forecast billing determinants along with present and proposed base rates.

Q. Please highlight and summarize the rate design changes proposed by the Company.

A. In this case the Company is proposing to increase the residential single-family basic charge from $11 to $16 and the multi-family basic charge from $8 to $9. For large non-residential customers with load sizes greater than 25,000 kW who did not receive a Line Extension Allowance more than the cost of metering, the Company is proposing a Customer-Funded Substation Credit.

For other rate schedules, the Company generally proposes applying the rate change on an equal percentage basis to the different functionalized prices.

The Company proposes improving and consolidating its time-of-use options.

A. <u>Residential Rate Design</u>

Q. Please explain the proposed tariffs for residential customers.

A. The standard rate schedule for residential customers is Delivery Service Schedule 4. The Company proposes increasing the basic charge from its current level of $11 per month to $16 for single-family customers and from $8 to $9 for multi-family customers. This change better reflects the fixed costs of serving residential customers and more fairly apportions cost between fixed and volumetric 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/1909.

Q. Why is the Company proposing an increase in its basic charge for residential customers?

A. The Company's marginal cost-of-service study which I present as Exhibit PAC/1908 shows on Table 3 that the annual marginal cost of billing- and commitment-related cost is $414.10 or about $34.51 per month. Exhibit PAC/1911 shows each of these marginal cost categories in total for the residential class as well as broken out for single-family and multi-family customers. The cost categories of line transformers and distribution poles and conductor were differentiated for single- and multi-family customers by weighting these categories by the number of customers per transformer and distance from substation, respectively. At the present prices of $11 for single family and $8 for multi-family, the Company's 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.

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 compare 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 (IOUs) 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	Single Family Basic Charge	Multi-Family Basic Charge
Current Pacific Power	$11.00	$8.00
Proposed Pacific Power	$16.00	$9.00
Portland General Electric	$13.00	$10.00
Idaho Power	$8.00	Same
Central Electric Coop	$28.16	Same
Central Lincoln PUD	$27.00	Same
City of Ashland	$16.25	Same
City of Hermiston	$21.00	Same
City of Monmouth	$11.95	Same
Coos-Curry Electric Coop	$28.38	Same
Eugene Water and Electric Board	$23.50	Same
Hood River Electric Coop	$19.00	Same
Lane Electric Coop	$41.00	Same
Salem Electric	$20.00	Same
Springfield Utility Board	$17.40	Same
Tillamook PUD	$32.00	Same
Umatilla Electric Coop	$26.00	Same
Average	$22.18	

Note - Prices were those available from each utility's website as of January 25, 2024

The average single family basic charge of all 15 utilities examined is $22.18 which is well above the Company's proposed basic charge of $16 for single-family. Besides the Company, only Portland General Electric Company has a different basic charge for multi-family customers which is presently set at $10. This level is above both the Company's current and proposed price for multi-family customers.

Q. What rate design change does the Company propose for residential customers who receive three-phase service?

A. The Company proposes to replace the demand charge and demand charge minimum that are applicable to three-phase residential customers with a phase-differentiated basic charge. Under this new structure for three-phase customers, three-phase customers would pay a basic charge that is $9 higher per month than single-phase customers.

Q. Why is the Company proposing this change for three-phase residential customers?

A. A higher basic charge instead of a demand charge and associated minimum charge is easier for customers to understand, simplifies metering, and better aligns with cost causation.

Q. What is the basis for a basic charge for three-phase residential customers that is $9 higher than the basic charge for single-phase customers?

A. Three-phase residential customers typically require the Company to install a three-phase instead of a single-phase transformer. Per Section II.D of the Company's Rule 13 – Line Extensions, customers requesting three-phase service pay for the initial additional capital cost for three-phase facilities. However, the Company must continue to maintain this equipment. $9 per month represents the Company's estimate of the incremental cost to maintain a three-phase transformer. Exhibit PAC/1912 provides the details behind the Company's calculation.

Q. How many three-phase residential customers does the Company have?

A. Three-phase service for residential customers is fairly uncommon. The Company only has 240 three-phase residential customers, which is about 0.05 percent of the total residential customer count.

B. <u>Non-Residential Rate Design</u>

Q. What does the Company propose for the rate design for non-residential customers?

A. The Company is proposing a Capacity Reservation Charge and an Excess Demand Charge that would be applicable to large customers who reserve more power than they require or use more than the level for which they have contracted. Company witness Anna DeMers supports these two charges in her direct testimony. Besides the proposed Capacity Reservation Charge and the Excess Demand Charge, the Company is not proposing any changes to the underlying rate structures for existing 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/1909.

Q. Is the Company making any rate design proposals that will be applicable to future non-residential customers?

A. Yes. In 2023, the Company requested, and the Commission approved changes to Rule 13 which limited the Line Extension Allowance that new load requests of 25,000 kW or greater receive to the cost of the metering necessary to measure their usage. In its order approving this change,[5] the Commission directed the Company "to change the

[5] Order No. 23-472 issued on December 12, 2023, in Docket No. UE 424

long-run incremental cost study in its next general rate case to ensure that distribution voltage customers larger than 25,000 kilowatts are not overallocated distribution and substation costs." In the forecast test period, there will be no customers energized who would have received the modified Line Extension Allowance treatment. The cost-of-service study itself was therefore not changed for this circumstance. However, the Company is proposing that distribution voltage customers with a load request greater than 25,000 kW who received a Line Extension Allowance equal to the cost of the metering necessary to measure their usage would receive a Customer-Funded Substation Credit to ensure that these customers are not overallocated distribution substation costs. The Company proposes that the Customer-Funded Substation Credit be set at $1.50 per kW of Facility Capacity[6] in Schedule 48. Exhibit PAC/1913 shows the calculation of the Customer-Funded Substation Credit. The Customer-Funded Substation Credit was set at a level that removes the cost of the return on and return of distribution substations that are in primary Schedule 48 rates. Notably, the operations and maintenance expense for distribution substations was not removed. If a large customer pays for the cost of the substation serving it upfront in its line extension advance, it is appropriate to remove that cost from rates for this customer, but the Company will still need to operate and maintain that substation.

C. <u>Adjustment Schedules</u>

Q. Please describe the proposed new adjustment schedules.

A. As discussed in the direct testimony of Company witness Joelle R. Steward, the Company is proposing an Insurance Cost Adjustment and a surcharge to collect funds

[6] In Schedule 48, "Facility Capacity" is defined as 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.

for a Catastrophic Fire Fund. The Company proposes that insurance costs be recovered through Schedule 80 – Insurance Cost Adjustment. The Company proposes that funds for the Catastrophic Fire Fund be collected through Schedule 193 – Catastrophic Fire Fund Adjustment.

Q. How does the Company propose setting rates for Schedule 80 – Insurance Cost Adjustment?

A. Since insurance costs are the result of managing risk for all aspects of a utility's operations, the Company proposes allocating their costs to each class on an equal percentage of base revenue. The Company would collect these costs from customers through a cents per kWh surcharge. Page 12 of Exhibit PAC/1909 shows the allocation and prices for Schedule 80, which would recover approximately $50.4 million per year in base revenue and would recover approximately $15.5 million in deferred costs.

Q. How does the Company propose setting rates for Schedule 193 – Catastrophic Fire Fund?

A. The risk associated with catastrophic fires is correlated with the presence of overhead line infrastructure. The Company therefore proposes allocating the Catastrophic Fire Fund to each class based upon its share of unbundled distribution revenue requirement. The Company would collect these funds from customers through a cents per kWh surcharge. Page 13 of Exhibit PAC/1909 shows the allocation and prices for Schedule 193, which would recover approximately $77.8 million per year after the rounding of rates.

Q. What change does the Company propose for Schedule 190 – Wildfire Mitigation Plan Cost Recovery Adjustment?

A. As discussed in the direct testimony of Company witness Sherona L. Cheung, the Company is proposing moving costs out of base rates and into the Wildfire Mitigation Plan Automatic Adjustment Clause. Accordingly, the Company is proposing to recover approximately an additional $21.3 million from Schedule 190. Page 14 of Exhibit PAC/1909 shows the proposed price changes for Schedule 190.

D. <u>Time-of-Use Options</u>

Q. Please summarize the Company's proposed changes to its time-of-use offerings.

A. The Company proposes moving Schedule 6, Pilot for Residential Time-of-Use Service, from its status of being a pilot to being an ongoing program through Schedule 4. The Company proposes introducing a new time-of-use option for small general service customers on Schedule 23 that has the same structure as the residential time-of-use program. The Company proposes moving Schedule 29, Pilot for General Service Time-of-Use, from its status of being a pilot to being an ongoing program with some modifications that will enhance its time varying price signal. For the irrigation time-of-use option on Schedule 41, Agricultural Pumping Service, the Company proposes increasing the on- to off-peak price differential. Finally, the Company proposes eliminating legacy optional Schedule 210, Portfolio Time-of-Use Supply Service, by June 1, 2025—five months after the January 1, 2025, effective date of this general rate case to provide adequate notice to affected participants and give them an opportunity to transition to other applicable time-of-use options. Schedule 210 would be closed to new service beginning January 1, 2025.

Q. Please list all of the time-of-use options that are currently available to the Company's customers.

A. The following time-of-use options are available to customers:

- Schedule 210 – Portfolio Time-of-Use Option for Residential
- Schedule 210 – Portfolio Time-of-Use Option for Small General Service
- Schedule 210 – Portfolio Time-of-Use Option for Small Irrigation
- Schedule 6 – Residential Time-of-Use Pilot
- Schedule 29 – Non-Residential Time-of-Use Pilot
- Schedule 41 – Irrigation Time-of-Use Option
- Schedule 45 – Public DC Fast Charger Transitional Rate

Table 3 lists the eligibility of these different options to different customer types.

Table 3. Time-of-Use Option Eligibility

	Residential	Non-Residential (<31 kW)	Non-Residential (31-200 kW)	Non-Residential (201-1,000 kW)	Irrigation (<31 kW)	Irrigation (31 kW & greater)
Schedule 210 Portfolio TOU	X	X			X	
Schedule 6 TOU	X					
Schedule 29 TOU		X	X	X		
Schedule 41 TOU Option					X	X
Schedule 45 Transitional Rate		*	*	*		

X- Applicable
*- Applicable in limited circumstances

Residential and small irrigation customers have available to them two different time-of-use options. Mid-sized general service and larger irrigation have only one option available to them. There is also a time-of-use option (Schedule 45) that is only available to publicly available electric vehicle charging stations under limited circumstances.

Q. Are any of the time-of-use options pilots?

A. Yes. Residential Time-of-Use Schedule 6 and Non-Residential Time-of-Use Schedule 29 are pilot programs that were established in the 2021 Rate Case. A final report on each pilot is due after they have been in place for three years. Both became effective on January 1, 2021, so this initial three-year period has elapsed.

Q. Has the Company evaluated these pilots?

A. Yes. The Company has evaluated the Residential Time-of-Use Schedule 6 pilot and the Non-Residential Time-of-Use Schedule 29 pilot. The final reports for Schedule 6 and Schedule 29 are provided as Exhibit PAC/1914 and Exhibit PAC/1915, respectively.

Q. Was there another pilot that the Company conducted as a result of the 2021 Rate Case?

A. Yes. The Company also conducted a pilot for interruptible service for large customers which was offered under Schedule 218. No customers participated in this pilot.

Q. Did the Company evaluate the Interruptible Service pilot?

A. No. The Company proposed and the Commission approved a more robust suite of demand response options and discontinued the Schedule 218 Interruptible Service pilot.[7] No report was therefore prepared for Interruptible Service Schedule 218.

Q. Please present the Schedule 6 pilot evaluation.

A. The Company's final report on the Residential Time-of-Use Schedule 6 pilot is provided as Exhibit PAC/1914. The pilot experienced steadily increasing levels of

[7] See the Commission's Disposition Letter dated November 15, 2022, in Docket No. ADV 1436.

enrollment, high participant satisfaction, meaningful customer bill savings, and system cost savings. The evaluation recommends continuing the program.

Q. What does the Company propose for Residential Time-of-Use Schedule 6?

A. The Company proposes moving the design and program structure of the Schedule 6 from its status as a pilot to being an ongoing optional offering available to residential customers that is listed under Residential Schedule 4.

Q. Please describe the Company's proposal for a new time-of-use option for Small General Service Schedule 23 customers.

A. In light of the success of the Residential Time-of-Use Schedule 6 pilot, the Company believes that providing a very similar program for small general service customers is in the public interest. The Company proposes that a new time-of-use option for Small General Service Schedule 23 customers be made available that would have the same time-of-use hours and program structure to the time-of-use option for residential customers. On-peak hours would be 5:00 p.m. to 9:00 p.m. every day and all other hours would be considered off-peak. The proposed credit for off-peak usage for participants in the time-of-use option is set to be the difference in average Western Energy Imbalance Market (WEIM) prices between on- and off-peak hours for the 36 month period ended June 2023 of 2.532 cents per kWh which is about a cent higher than the off-peak credit of 1.438 cents per kW provided on legacy Schedule 210 for small general service customers. To achieve a revenue neutral rate design, the Company proposes an on-peak adder for Schedule 23 of 12.578 cents per kWh. The Company solved for the on-peak surcharge price by applying the off-peak credit price to the estimated off-peak energy for all of Schedule 23 and dividing this revenue by the estimated on-peak energy for all of Schedule 23. Exhibit PAC/1916 shows the calculations used to develop the on-peak surcharge and off-peak credit for the new Schedule 23 time-of-use option. Table 4 shows how the base energy prices for the time-of-use option would compare to standard Schedule 23 rates.

Table 4. Comparison of Proposed Energy Prices for the Time-of-Use Option and Standard Schedule 23

Description	Schedule 23 Time-of-Use Option	Standard Schedule 23 Pricing
1st 3,000 kWh, On-Peak, Secondary Voltage	28.135¢ per kWh	15.557¢ per kWh
1st 3,000 kWh, Off-Peak, Secondary Voltage	13.025¢ per kWh	15.557¢ per kWh
All additional kWh, On-Peak, Secondary Voltage	26.372¢ per kWh	13.794¢ per kWh
All additional, Off-Peak, Secondary Voltage	11.262¢ per kWh	13.794¢ per kWh

Q. Please present the Schedule 29 pilot evaluation.

A. The Company's final report on the Non-Residential Time-of-Use Schedule 29 pilot is provided as Exhibit PAC/1915. The Company only had one participant who had been on the program for a partial year. The analysis presented in the report was therefore fairly limited. The Company continues to believe though that the program holds promise particularly for transportation electrification customers with low levels of utilization.

Q. What does the Company propose for Non-Residential Time-of-Use Schedule 29?

A. The Company proposes that the same structure for Schedule 29 be preserved, but that the time-varying element of the program be structured similarly to the residential and small general service time-of-use options. This would standardize the time-of-use periods for residential, small general service and mid-sized general service customers.

Increasing the time use differential will also provide greater opportunities for customers who do have load shifting opportunities to save on their bills. On-peak hours would be 5:00 p.m. to 9:00 p.m. every day and all other hours would be considered off-peak. Off-peak usage for participants on Schedule 29 would receive the same 2.532 cent per kWh credit as small general service time-of-use option participants. To achieve a revenue neutral rate design with Schedule 28 and Schedule 30, the Company proposes an on-peak adder of 13.014 cents per kWh. Exhibit PAC/1916 shows the calculations used to develop the on-peak surcharge and off-peak credit for Schedule 29. Since small general service customers are not subject to a demand charge for all of their kW usage, Schedule 29 is unlikely to be a good option for Schedule 23 customers. The Company therefore proposes limiting eligibility for Schedule 29 participants to “Large Nonresidential Consumers”, which is a defined term in the tariffed rules and generally means a non-residential customer with a load size larger than 30 kW.

Q. Please describe the Agricultural Pumping Service Schedule 41 time-of-use option?

A. Schedule 41 irrigation customers can enroll in a time-of-use option which has time varying energy charges during the peak irrigating months of July, August, and September. To provide flexibility for pumpers who take water from an irrigation project, two choices are provided for on-peak hours – Option A which sets on-peak from 2:00 p.m. to 6:00 p.m. every day during the season and Option B which sets on-peak from 6:00 p.m. to 10:00 p.m. every day during the season. Off-peak energy usage receives a credit against regular charges of 0.992 cents per kWh and on-peak usage incurs a charge of 4.989 cents per kWh on top of standard charges. In December 2023, 113 out of a total of 7,891 Schedule 41 customers participated in the time-of-use option.

Q. Does the Company propose any changes for the Agricultural Pumping Service Schedule 41 time-of-use option?

A. Yes. To encourage greater enrollment in the option and to send a stronger price signal to shift load away from on-peak periods, the Company proposes increasing the on- to off-peak differential. Using similar logic to the calculation of the off-peak price for the Schedule 23 time-of-use option and for Schedule 29, the Company took the difference of WEIM prices between Schedule 41's on- and off-peak times to develop a 2.696 cents per kWh off-peak credit. To achieve a revenue neutral rate design for the whole class, a 12.030 cents per kWh on-peak surcharge is required. Exhibit PAC/1916 shows the calculations used to develop the on-peak surcharge and off-peak credit for the Schedule 41 time-of-use option.

Q. Please describe legacy Portfolio Time-of-Use Schedule 210.

A. As a requirement of Oregon Administrative Rule 860-038-0220, the Company was required to provide residential and small non-residential customers with a portfolio of product and pricing options. Along with options that provided customers with access to renewables, time-of-use pricing was made available through Schedule 210 to residential, small general service, and small irrigation customers. Schedule 210 became effective on March 1, 2002, nearly 22 years ago. Schedule 210 has not been a very popular program. It has low levels of participation and bill savings for participants have been meager. Table 5 shows the average number of customers enrolled along with the average monthly bill savings for the historic base period of 12 months ended June 2023.

Table 5. Schedule 210 Enrollment and Bill Savings

	Average Customers	Average Monthly Savings
Residential	952	$0.98
Small General Service	211	$1.58
Irrigation	19	$2.78

The time-of-use periods for Schedule 210 are more complex than for the newer Residential Time-of-Use Schedule 6 pilot or the Agricultural Pumping Service Schedule 41 Time-of-Use Option. Under Schedule 210, between the winter months of November through March, on-peak periods are Monday through Friday, excluding holidays, from 6:00 a.m. to 10:00 a.m. and again from 5:00 p.m. to 8:00 p.m. Between the summer months of April through October, on-peak periods on Schedule 210 are Monday through Friday, excluding holidays, from 4:00 p.m. to 8:00 p.m. All other hours are considered off-peak.

Q. What does the Company propose for legacy Portfolio Time-of-Use Schedule 210?

A. The Company proposes eliminating legacy Schedule 210 by June 1, 2025, five months after the rate effective date of this proceeding, in order to give adequate notice to participants and provide them with sufficient time to consider transitioning to a different time-of-use option. Residential Schedule 210 could choose to move to the time-of-use option listed on Residential Schedule 4, Small General Service Schedule 210 could choose to move to the time-of-use option listed on Small General Service Schedule 23, and Agricultural Pumping Service Schedule 210 could choose to move to the time-of-use option listed on Agricultural Pumping Service Schedule 41. Under the Company's proposal, Schedule 210 would be closed to new service starting on the rate effective date in this rate case of January 1, 2025.

Q. Why does the Company propose eliminating legacy Portfolio Time-of-Use Schedule 210?

A. Schedule 210 has confusing time periods, offers only very limited savings, and has not been very popular. The Company believes that now is the right time to transition to more robust time-of-use options for its customers. Keeping legacy Schedule 210 along with other options would create confusion for customers.

VII. ELIMINATION OF PAYMENT FEES

Q. Do the Company's customers pay fees for some methods of payment that they use to pay their bills?

A. Yes. The Company's vendors charge fees to customers who make a payment at a pay station or pay their bills with a credit or debit card. These costs are passed onto customers making these types of payments to keep its rates lower for everyone. Customers can pay their bills without a fee if they pay by sending a check or transferring funds from a bank account electronically, which are options that have minimal cost to the Company.

Q. What are some of the consequences of charging fees for customers who pay at a pay station or with a credit or debit card?

A. Customers who use pay stations to make a payment can be in a crisis and need to make a fast payment to restore their power after a shut-off for non-payment. They may also be un-banked and not have the ability to pay with a check or an electronic draft. Customers who pay their power bill with a credit card may be doing so because they are in a tight spot financially and do not have the cash on hand to pay from a bank account. For vulnerable customers experiencing financial constraints, facing additional fees to pay their power bills can set them back further and increase their energy burden.

Q. In light of these consequences, what does the Company propose?

A. The Company proposes eliminating fees associated with using a pay station or making payment with a debit or credit card. Eliminating these fees will remove a hardship that vulnerable customers face and make it easier for them to pay their electricity bills using a method that is feasible for them in their situation. It is the Company's understanding that both Portland General Electric Company and Northwest Natural do not charge fees for payments made through a pay station or with a card.

Q. What is the cost of eliminating fees for pay stations and credit/debit card payments?

A. During the historic base period, customers paid about $4.8 million in fees for using a pay station and paying with a card. The Company's revenue requirement has been adjusted to reflect this additional cost. That adjustment is supported by Company witness Cheung. Exhibit PAC/1917 shows the details of this cost.

VIII. CONCLUSION

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 433
Exhibit PAC/1901
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Proposed Tariffs

February 2024

PACIFIC POWER
A DIVISION OF PACIFICORP

Issued February 14, 2024
Matthew McVee, Vice President, Regulation

Effective for service on and after January 1, 2025
Advice No. 24-001/Docket No. UE 433

+Schedule No.

Issued February 14, 2024
Matthew McVee, Vice President, Regulation
Effective for service on and after January 1, 2025
Advice No. 24-001/Docket No. UE 433

PACIFIC POWER
A DIVISION OF PACIFICORP

RESIDENTIAL SERVICE
DELIVERY SERVICE

OREGON
SCHEDULE 4

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.

Distribution Charge		
Single-Family Home Basic Charge, per month	$16.00	(I)
Multi-Family Home Basic Charge, per month	$9.00	(I)
Three-Phase Charge, per month	$9.00	(N)
		(D)
Distribution Energy Charge, per kWh	5.433¢	(I)
Transmission & Ancillary Services Charge		
Per kWh	0.844¢	(R)
System Usage Charge		
Schedule 200 Related, per kWh	0.070¢	(R)
T&A and Schedule 201 Related, per kWh	0.132¢	(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 211, Schedule 212 or Schedule 213, as appropriate and in accordance with the Applicable section of the specified rate schedule. (D)

Time-of-Use Option (N)

Consumers taking service under this schedule may also choose to participate in a time-of-use option, which provides time-varying energy rates. Rates and hours for this option are shown in Schedule 201. (N) (N) (N)

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.

(D)

(continued)

Special Conditions (N)

1. The Consumer must have a time-of-use capable meter installed to participate in the time-of-use option. The appropriate meter will be installed or the existing meter reprogrammed on the Consumer premises at no extra charge to the Consumer. Billing under the time-of-use option shall begin for the Consumer following the meter update and the initial meter reading.
2. Consumers requesting to participate in the time-of-use option agree to remain on the option for one year. The Consumer shall remain on the option until Consumer notifies the Company.
3. The Company shall guarantee against excessive increase of consumer costs for the first year of enrollment in the time-of-use option. If the total energy costs incurred on the option for the first year exceed 10% over what costs would have been for the same period under Cost-Based Supply Service, the net difference, Guarantee Payment, will be credited on the customer's bill following the end of the first year of service under the program. No Guarantee Payment shall be given if Consumer discontinues participation on the option before the end of the first year on the program. (N)

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 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	$16.00	(I)
Multi-Family Home Basic Charge, per month	$9.00	(I)
Three-Phase Charge, per month	$9.00	(C)(I) (D)
Distribution Energy Charge, per kWh	5.433¢	(I)
Transmission & Ancillary Services Charge		
Per kWh	0.844¢	(R)
System Usage Charge		
Schedule 200 Related, per kWh	0.070¢	(R)
T&A and Schedule 201 Related, per kWh	0.132¢	(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 211, Schedule 212 or Schedule 213, as appropriate and in accordance with the Applicable section of the specified rate schedule. (D)

Time-of-Use Option (N)

Consumers taking service under this schedule may also choose to participate in a time-of-use (N)
option, which provides time-varying energy rates. Rates and hours for this option are shown in (N)
Schedule 201. (N)

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.

(M) to pg. 2

(continued)

Special Conditions (N)

1. The Consumer must have a time-of-use capable meter installed to participate in the time-of-use option. The appropriate meter will be installed or the existing meter reprogrammed on the Consumer premises at no extra charge to the Consumer. Billing under the time-of-use option shall begin for the Consumer following the meter update and the initial meter reading.
2. Consumers requesting to participate in the time-of-use option agree to remain on the option for one year. The Consumer shall remain on the option until Consumer notifies the Company.
3. The Company shall guarantee against excessive increase of consumer costs for the first year of enrollment in the time-of-use option. If the total energy costs incurred on the option for the first year exceed 10% over what costs would have been for the same period under Cost-Based Supply Service, the net difference, Guarantee Payment, will be credited on the customer's bill following the end of the first year of service under the program. No Guarantee Payment shall be given if Consumer discontinues participation on the option before the end of the first year on the program. (N)

Continuing Service (M) from pg. 1

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.

(M)

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	$11.00
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	4.307¢
Transmission & Ancillary Services Charge	
Per kWh	0.919¢
System Usage Charge	
Schedule 200 Related, per kWh	0.077¢
T&A and Schedule 201 Related, per kWh	0.115¢

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

CANCELED

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 6

PILOT FOR RESIDENTIAL TIME-OF-USE SERVICE
DELIVERY SERVICE

Guarantee Payment

The Company shall guarantee against excessive increase of consumer costs for the first year of enrollment in the program. If the total energy costs incurred on this Schedule for the first year exceed 10% over what costs would have been for the same period under Cost-Based Supply Service, the net difference, Guarantee Payment, will be credited on the customer's bill following the end of the first year of serviced under the program. No Guarantee Payment shall be given if Consumer terminates service on the program before the end of the first year on the program.

Special Conditions

1. Consumers taking service under this schedule shall be subject to all conditions applicable to Schedule 4 of this tariff.

2. Participants for this program will be chosen on a first-come, first-served basis. Participation will be limited to approximately twenty-five thousand (25,000) metered points.

3. The Consumer must have a time-of-use capable meter installed to participate in this option. The appropriate meter will be installed or the existing meter reprogrammed on the Consumer premises at no extra charge to the Consumer. Billing under this schedule shall begin for the Consumer following the meter update and the initial meter reading.

4. Consumers requesting service under this pilot program agree to remain on the pilot for one year. Consumers will have the option to opt out of the pilot after this date by notifying the Company. Service will continue under this schedule until Consumer notifies the Company to discontinue service or this schedule terminates.

5. All Consumers participating in this pilot program may be asked to complete a survey regarding participation. Survey responses will be used to further evaluate the potential of future time-of-use rates. Data gathered will be used for pilot evaluation only.

6. Consumers on this tariff schedule shall have a term of not less than one year. Service will continue under this schedule until Consumer notifies the Company to discontinue service.

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.

CANCELED

Issued December 28, 2020
Etta Lockey, Vice President, Regulation

Effective for service on and after January 1, 2021
Advice No. 20-017/Docket No. UE 374

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 7

Purpose

The purpose of this Schedule is to implement the Low-Income Discount for income qualified Residential Customers and General Service customers who qualify under Special Condition 10 of this tariff.

This discount is enabled by House Bill 2475 (2021 regular sessions), which modified ORS 757.230 to allow for differentiated rates for "low-income customers and other economic, social equity, or environmental justice factors that affect affordability for certain classes of utility customers."

Available

To Residential Customers and General Service Customers who qualify under Special Condition 10 of this tariff and are served by the Company within its service territory.

Applicable

To income-qualified Residential Customers with gross household income at or below 60% of Oregon State Median Income (SMI) adjusted for household size. For Customers in single-person households, eligibility is extended to those with gross household incomes up to the greater of 60% SMI or full-time wages at Portland minimum wage. Also applicable to General Service Customers who qualify under Special Condition 10 of this tariff.

Monthly Billing

Income-qualified Residential Customers will receive a monthly bill discount at one of two levels based on the Customer's household income as a percentage of SMI for the Residential Service Schedule charges for that Customer (Schedule 4 or 5). Customers with household incomes up to (D) 20% of SMI will receive a 40% discount on their electricity bill and customers with household incomes between 21% and 60% will receive a 20% discount on their electricity bill. The monthly bill discount will be applied prior to taxes and will not apply to Schedule 300 charges.

General Service Customers who qualify under Special Condition 10 of this tariff will receive a 30% discount on their electricity bill. The monthly bill discount will be applied prior to taxes and will not apply to Schedule 300 charges. General Service Customers receiving this discount must meet and comply with the terms of Special Condition 10 of this tariff.

(continued)

Issued February 14, 2024
Matthew McVee, Vice President, Regulation

Effective for service on and after January 1, 2025
Advice No. 24-001/Docket No. UE 433

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	$7.89	(I)
Level 2	5,001-12,000	34	$9.05	(I)
Level 3	12,001+	57	$10.74	(I)

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	$22.10	$22.10	(I)
Three Phase, per month	$32.95	$32.95	(I)
Load Size Charge			
≤ 15 kW	No Charge	No Charge	
> 15 kW, per kW for all kW in excess of 15 kW Load Size	$2.10	$2.10	(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	$6.87	$6.78	(I)
Distribution Energy Charge, per kWh	5.080¢	5.001¢	(I)
Reactive Power Charge, per kvar	$0.65	$0.60	
Transmission & Ancillary Services Charge			
Per kWh	1.042¢	1.026¢	(I)
System Usage Charge			
Schedule 200 Related, per kWh	0.064¢	0.063¢	(R)
T&A and Schedule 201 Related, per kWh	0.128¢	0.126¢	(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)

Issued February 14, 2024
Matthew McVee, Vice President, Regulation
Effective for service on and after January 1, 2025
Advice No. 24-001/Docket No. UE 433

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 the Company's demand meter for the 15-minute period of the Consumer's greatest use during the month, determined to the nearest kW.

Metering Adjustment

For a Consumer receiving service at secondary delivery voltage where metering is at primary delivery shall have all billing quantities multiplied by an adjustment factor of 0.9845.

For a Consumer receiving service at primary delivery voltage where metering is at secondary delivery voltage shall have all billing quantities multiplied by an adjustment factor of 1.0157.

Communication Devices

Communication devices with fixed loads that are installed on streetlights, traffic signals or elsewhere and connected to the Company's system for electric service may be unmetered and shall be served under this schedule in accordance with Rule 7.C. Such unmetered devices not exceeding 35 line watts per unit, served under multiple Points of Delivery to a single Consumer, may be grouped under a single Consumer account for billing purposes such that the Consumer pays a single Basic Charge for multiple units in addition to a per unit energy-based charge. Not more than 100 units shall be grouped under a single account.

All devices are required to be installed and maintained under a pole attachment agreement. The Consumer is required to notify the Company in writing and receive subsequent approval prior to installation, modification or removal of any device.

All devices mounted to Company owned facilities shall be installed, maintained, transferred or removed only by qualified personnel approved in advance by the Company. If approved qualified personnel are not available or at the Company's discretion, the Company may perform these functions at the Consumer's expense.

Supply Service Options

All Small Nonresidential 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, Schedule 211, Schedule 212, Schedule 213, or Schedule (D)
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 723, Direct Access Delivery Service. (M) to pg. 3

Time-of-Use Option (N)

Consumers taking service under this schedule who choose Supply Service Schedule 201, 211, (N)
212 or 213 may also choose to participate in a time-of-use option which provides time-varying (N)
energy rates. Rates and hours for this option are shown in Schedule 201. (N)

(continued)

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. (M) from pg. 2 (M)

Special Conditions

1. The Consumer shall not resell electric service received from the Company under provisions of this Schedule to any person, except by permission of the Company or as otherwise expressly provided in Company tariffs. (T)
2. The Consumer must have a time-of-use capable meter installed to participate in the time-of-use option. The appropriate meter will be installed or the existing meter reprogrammed on the Consumer premises at no extra charge to the Consumer. Billing under the time-of-use option shall begin for the Consumer following the meter update and the initial meter reading. (N)
3. Consumers requesting to participate in the time-of-use option agree to remain on the option for one year. The Consumer shall remain on the option until Consumer notifies the Company. (N)

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.

Term of Contract

The Company may require the Consumer to sign a written contract which shall have a term of not less than one year.

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.

Issued February 14, 2024
Matthew McVee, Vice President, Regulation
Effective for service on and after January 1, 2025
Advice No. 24-001/Docket No. UE 433

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	$ 25.00	$ 35.00	(I)
Load Size 51-100 kW, per month	$ 47.00	$ 60.00	(I)
Load Size 101 - 300 kW, per month	$111.00	$138.00	(I)
Load Size > 300 kW, per month	$156.00	$197.00	(I)
Load Size Charge			
≤50 kW, per kW Load Size	$ 1.60	$ 1.95	(I)
51 - 100 kW, per kW Load Size	$ 1.25	$ 1.55	(I)
101 – 300 kW, per kW Load Size	$ 0.75	$ 0.95	(I)
> 300 kW, per kW Load Size	$ 0.50	$ 0.50	(I)
Demand Charge, per kW	$ 5.31	$ 6.78	(I)
Distribution Energy Charge, per kWh	0.536¢	0.103¢	(I)
Reactive Power Charge, per kvar	$ 0.65	$ 0.60	
Transmission & Ancillary Services Charge			
Per kW	$ 1.74	$ 2.13	(R)(I)
System Usage Charge			
Schedule 200 Related, per kWh	0.067¢	0.060¢	(R)
T&A and Schedule 201 Related, per kWh	0.126¢	0.111¢	(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

GENERAL SERVICE TIME-OF-USE
LARGE NONRESIDENTIAL
DELIVERY SERVICE (C)

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 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. (C) (D)

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	$49.00	(I)
Distribution Energy Charge		
First 50 kWh per kW demand, per kWh	24.942¢	(I)
All Additional kWh, per kWh	-1.758¢	(I)
Transmission & Ancillary Services Charge		
Per kWh	0.582¢	(R)
System Usage Charge		
Schedule 200 Related, per kWh	0.067¢	(R)
T&A and Schedule 201 Related, per kWh	0.126¢	(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. Time-of-use rates and hours for Supply Service under this schedule are shown in Schedule 201. (N) (N)

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)

(C)

(D)

Special Conditions

1. Consumers taking service under this schedule shall be subject to all conditions applicable to Schedule 28 of this tariff. (D)

2. The Consumer must have a time-of-use capable meter installed to participate in this option. The appropriate meter will be installed or the existing meter reprogrammed on the Consumer premises at no extra charge to the Consumer. Billing under this schedule shall begin for the Consumer following the meter update and the initial meter reading. (T)

3. Consumers requesting service under this schedule agree to remain on the schedule for one year. Service will continue under this schedule until Consumer notifies the Company to discontinue service or this schedule terminates. (T)(C) (C)(D)

(D)

4. Meters taking service under this schedule will not be eligible to participate concurrently in net metering or any other generation related program offered by the Company. (T)(C)

Continuing Service

Except as specifically provided otherwise, the rates of this tariff are based on continuing service at each service location. Disconnect and reconnect transactions shall not operate to relieve a seasonal Consumer from minimum monthly charges.

Term of Contract

The Company may require the Consumer to sign a written contract which shall have a term of not less than one year.

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 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	$704.00	$642.00	(I)
Load Size 201 - 300 kW, per month	$204.00	$202.00	(I)
Load Size > 300 kW, per month	$541.00	$527.00	(I)
Load Size Charge			
≤200 kW, per kW Load Size	No Charge	No Charge	
201 – 300 kW, per kW Load Size	$2.50	$2.20	(I)
> 300 kW, per kW Load Size	$1.20	$1.10	(I)
Demand Charge, per kW	$5.92	$5.59	(I)
Reactive Power Charge, per kvar	$0.65	$0.60	
Transmission & Ancillary Services Charge			
Per kW	$2.45	$2.29	(R)
System Usage Charge			
Schedule 200 Related, per kWh	0.065¢	0.065¢	(R)
T&A and Schedule 201 Related, per kWh	0.121¢	0.121¢	(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)

Issued February 14, 2024
Effective for service on and after January 1, 2025
Matthew McVee, Vice President, Regulation
Advice No. 24-001/Docket No. UE 433

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	$580.00	$570.00	(I)
Three Phase Load Size > 300 kW	$2,300.00	$2,270.00	(I)
Load Size Charge (November billing only)			
Single Phase Any Size, Three Phase ≤ 50 kW, per kW Load Size	$24.20	$23.90	(I)
Three Phase 51 - 300 kW, per kW Load Size	$16.60	$16.40	(I)
Three Phase > 300 kW, per kW Load Size	$10.20	$10.10	(I)
Single Phase, Minimum Charge	$105.00	$105.00	(I)
Three Phase, Minimum Charge	$170.00	$170.00	(I)
Distribution Energy Charge, per kWh	7.049¢	6.940¢	(I)
Reactive Power Charge, per kVar	$0.65	$0.60	
Transmission & Ancillary Services Charge			
Per kWh	0.660¢	0.650¢	(R)
System Usage Charge			
Schedule 200 Related, per kWh	0.058¢	0.057¢	(R)
T&A and Schedule 201 Related, per kWh	0.107¢	0.105¢	(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 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)

kW Load Size *(continued)*

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

In no case shall the Monthly kW be less than the average kW determined as:

$$\text{Average kW} = \frac{\text{kWh for billing month}}{\text{hours in billing month}}$$

Reactive Power Charge

The maximum 15-minute reactive takings for the billing month in kilovolt-amperes in excess of 40% of the Monthly kW.

Metering Adjustment

For a Consumer receiving service at secondary delivery voltage where metering is at primary delivery shall have all billing quantities multiplied by an adjustment factor of 0.9845.

For a Consumer receiving service at primary delivery voltage where metering is at secondary delivery voltage shall have all billing quantities multiplied by an adjustment factor of 1.0157.

Supply Service Options

All Consumers taking Delivery Service under this schedule shall pay the applicable rates in Schedule 200, Base Supply Service. A Small Nonresidential Consumer taking Delivery Service under this schedule shall additionally specify Supply Service Schedule 201, Schedule 211, (D) Schedule 212, Schedule 213, or Schedule 220, as appropriate and in accordance with the Applicable section of the specified rate schedule. A Large Nonresidential Consumer taking Delivery Service under this Schedule shall additionally 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 741, Direct Access Delivery Service.

Time-of-Use Options

Consumers taking service under this schedule who choose Supply Service Schedule 201, 211, (N)
212 or 213 may also choose to participate in one of two time-of-use options, Option A and (N)
Option B, which provide time-varying rates during the Summer months of July, August and September. Rates and hours for these options are shown in 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)

Special Conditions (T)

1. For new or terminating service, the Basic Charge and the Load Size Charge shall be prorated based upon the length of time the account is active during the 12-month period December through November; provided, however, that proration of the Basic Charge and the Load Size Charge will be available on termination only if a full Basic Charge and Load Size Charge was paid for the delivery point for the preceding year.

2. For new service or for reestablishment of service, the Company will require a written contract.

3. In the absence of a Consumer or Applicant willing to contract for service, the Company may remove its facilities.

4. Energy use may be carried forward and be billed in a subsequent billing month; provided, however, that energy will not be carried forward and be charged for at a higher rate than was applicable for the billing months during which the energy was used.

5. A Consumer may not at the same time participate in one of the time-of-use options and Schedule 106 or any other demand response program. (C)

6. The Consumer must have a time-of-use capable meter installed to participate in the time-of-use options. The appropriate meter will be installed or the existing meter reprogrammed on the Consumer premises at no extra charge to the Consumer. Billing under the time-of-use option shall begin for the Consumer following the meter update and the initial meter reading. (N)

7. Consumers requesting to participate in the time-of-use options agree to remain on the option for one year. The Consumer shall remain on the option until Consumer notifies the Company. (N)

Term of Contract
Not less than three years.

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 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	$820.00	$1,160.00	$1,770.00	(I)
Facility Capacity > 4,000 kW, per month	$2,260.00	$3,190.00	$4,550.00	(I)
Facilities Charge				
≤ 4,000 kW, per kW Facility Capacity	$2.60	$1.35	$1.35	(R)(I)(I)
> 4,000 kW, per kW Facility Capacity	$1.00	$0.55	$1.15	(R)(I)(I)
On-Peak Demand Charge, per kW	$6.42	$7.95	$6.21	(I)
Reactive Power Charges				
Per kvar	$0.65	$0.60	$0.55	
Per kVarh	$0.0008	$0.0008	$0.0008	
Customer Funded Substation Credit, per kW Facility Capacity	N/A	-$1.50	N/A	(N)(N)
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	$2.07	$2.73	$3.13	(I)
System Usage Charge				
Schedule 200 Related, per kWh	0.066¢	0.061¢	0.059¢	(R)
T&A and Schedule 201 Related, per kWh	0.122¢	0.113¢	0.109¢	(I)

(continued)

On-Peak Demand

The kW shown by or computed from the readings of the Company's demand meter for the On-Peak 15-minute period of the Consumer's greatest use during the month, determined to the nearest kW. 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.

Customer Funded Substation (N)

A Consumer will receive the Customer Funded Substation Credit if they take distribution voltage (N)
service, have a load size of 25,000 kW or greater, and received an Extension Allowance that (N)
was equal to the metering necessary to measure their usage. (N)

Metering Adjustment

A Consumer receiving service at secondary delivery voltage where metering is at primary delivery shall have all billing quantities multiplied by an adjustment factor of 0.9845.
A Consumer receiving service at primary delivery voltage where metering is at secondary delivery voltage shall have all billing quantities multiplied by an adjustment factor of 1.0157.

Baseline Demand

The kW of Demand supplied by the Company to the Large Nonresidential Consumer when the Consumer’s generator is regularly operating as planned by the Consumer. For new Partial Requirements Consumers, the Consumer’s peak Demand for the most recent 12 months prior to installing the generator, adjusted for planned generator operations, shall be used to calculate the Baseline Demand. Existing Partial Requirements Consumers shall select their Baseline Demand for each contract term based upon the Consumer’s peak demand for the most recent 12 months during the times the generator was operating as planned, adjusted for changes in load and planned generator operations. Planned generator operations includes changes in the electricity produced by the generator as well as the Consumer’s plans to sell any electricity produced by the generator to the Company or third parties. Any modification to the Baseline Demand must be consistent with Special Conditions in this schedule.

Facility Capacity

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, but shall not be less than the Consumer’s Baseline Demand. For new customers during the first three months of service under this schedule, the Facility Capacity will be equal to the Consumer’s Baseline Demand.

Reserves Charges

The Company provides Reserves for the Consumer’s Facility Capacity. Reserves consist of the following components:

Spinning Reserves

In addition to the Spinning Reserves provided for the Consumer’s Baseline Demand, Spinning Reserves provide Electricity immediately after a Consumer’s demand rises above Baseline Demand.

(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.

Distribution Charge		**Delivery Voltage**		
	Secondary	**Primary**	**Transmission**	
Basic Charge				
Facility Capacity ≤ 4,000 kW, per month	$820.00	$1,160.00	$1,770.00	(I)
Facility Capacity > 4,000 kW, per month	$2,260.00	$3,190.00	$4,550.00	(I)
Facilities Charge				
≤ 4,000 kW, per kW Facility Capacity	$2.60	$1.35	$1.35	(R)(I)(I)
> 4,000 kW, per kW Facility Capacity	$1.00	$0.55	$1.15	(R)(I)(I)
On-Peak Demand Charge, per kW	$6.42	$7.95	$6.21	(I)
Reactive Power Charge, per kvar	$0.65	$0.60	$0.55	
Customer Funded Substation Credit, per kW Facility Capacity	N/A	-$1.50	N/A	(N) (N)
Transmission & Ancillary Services Charge				
Per kW of On-Peak Demand	$2.61	$3.27	$3.67	(R)(I)(I)
System Usage Charge				
Schedule 200 Related, per kWh	0.066¢	0.061¢	0.059¢	(R)
T&A and Schedule 201 Related, per kWh	0.122¢	0.113¢	0.109¢	(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.

(M) to pg. 2

(continued)

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. (M) from pg. 1

On-Peak Demand

The kW shown by or computed from the readings of the Company's demand meter for the On-Peak 15-minute period of the Consumer's greatest use during the month, determined to the nearest kW. 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.

Customer Funded Substation (N)

A Consumer will receive the Customer Funded Substation Credit if they take distribution voltage service, have a load size of 25,000 kW or greater, and received an Extension Allowance that was equal to the metering necessary to measure their usage. (N) (N) (N)

Metering Adjustment

For a Consumer receiving service at secondary delivery voltage where metering is at primary delivery shall have all billing quantities multiplied by an adjustment factor of 0.9845.

For a Consumer receiving service at primary delivery voltage where metering is at secondary delivery voltage shall have all billing quantities multiplied by an adjustment factor of 1.0157.

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 748, 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 not resell electric service received from the Company under provisions of this Schedule to any person, except by permission of the Company or as otherwise expressly provided in Company tariffs.

Term of Contract

The Company may require the Consumer to sign a written contract which shall have a term of not less than one year.

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.

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	$ 6.53	$ 6.92	$ 7.07	$ 7.20	$ 7.65	$ 9.34	(I)
Functional Lighting - Customer Funded Conversion	$ 3.53	$ 3.72	$ 3.86	$ 3.94	$ 4.21	$ 5.18	(I)
Decorative Series	N/A	$ 11.92	$ 12.05	N/A	N/A	N/A	(I)

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	$ 1.32	$ 1.87	$ 2.72	$ 3.62	$ 4.89	$ 7.49	(I)

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	$ 1.66	$ 2.89	$ 4.00	$ 6.34	$ 15.06	(I)

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	4.255	(I)

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)

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	4.684¢	(I)
Transmission & Ancillary Services Charge		
per kWh	0.028¢	(R)
System Usage Charge		
Schedule 200 Related, per kWh	0.012¢	(R)
T&A and Schedule 201 Related, per kWh	0.020¢	

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)

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	$0.081	$0.106	$0.122	(I)
Daily ERP Demand Charge				
Per kW of Daily ERP On-Peak Demand	$0.250	$0.310	$0.242	(I)

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 80

INSURANCE COST ADJUSTMENT

(N)

Purpose

The purpose of this schedule is recover base and deferred insurance costs.

Applicable

To all Residential and Nonresidential Consumers.

Monthly Billing

All bills calculated in accordance with Schedules contained in the presently effective Tariff will have applied an amount equal to the product of all kWh multiplied by the following applicable rate as listed by Delivery Service schedule.

	Base Adjustment	Deferred Adjustment
Schedule 4	0.404 ¢ per kWh	0.125 ¢ per kWh
Schedule 5	0.404 ¢ per kWh	0.125 ¢ per kWh
Schedule 15	0.630 ¢ per kWh	0.194 ¢ per kWh
Schedule 23, 723	0.421 ¢ per kWh	0.130 ¢ per kWh
Schedule 28, 728	0.296 ¢ per kWh	0.091 ¢ per kWh
Schedule 30, 730	0.264 ¢ per kWh	0.081 ¢ per kWh
Schedule 41. 741	0.449 ¢ per kWh	0.138 ¢ per kWh
Schedule 47, 747	0.225 ¢ per kWh	0.069 ¢ per kWh
Schedule 48, 748, 848	0.225 ¢ per kWh	0.069 ¢ per kWh
Schedule 51, 751	0.630 ¢ per kWh	0.194 ¢ per kWh
Schedule 53, 752	0.630 ¢ per kWh	0.194 ¢ per kWh
Schedule 54, 754	0.630 ¢ per kWh	0.194 ¢ per kWh

(N)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 90

The following summarizes the applicability of the Company's adjustment schedules

SUMMARY OF EFFECTIVE RATE ADJUSTMENTS

(N)

Schedule	80	91	92	93	94	96	97	98*	190	192	193	194	198	202*	203*	204
4	x	x	x	x	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	x	x	x	x
15	x	x	x	x	x	x		x	x	x	x	x	x	x	x	x
23	x	x	x	x	x	x		x	x	x	x	x	x	x	x	x
28	x	x	x	x	x	x		x	x	x	x	x	x	x	x	x
30	x	x	x	x	x	x		x	x	x	x	x	x	x	x	x
41	x	x	x	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	x	x	x	x
48	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
51	x	x	x	x	x	x			x	x	x	x	x	x	x	x
53	x	x	x	x	x	x			x	x	x	x	x	x	x	x
54	x	x	x	x	x	x			x	x	x	x	x	x	x	x
60																
723	x	x	x	x	x	x		x	x	x	x	x	x	x	x	x
728	x	x	x	x	x	x		x	x	x	x	x	x	x	x	x
730	x	x	x	x	x	x		x	x	x	x	x	x	x	x	x
741	x	x	x	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	x	x	x	x
748	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
751	x	x	x	x	x	x			x	x	x	x	x	x	x	x
753	x	x	x	x	x	x			x	x	x	x	x	x	x	x
754	x	x	x	x	x	x			x	x	x	x	x	x	x	x
848	x	x	x		x		x		x	x	x					

(N)

*Not applicable to all consumers. See Schedule for details.

(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

Schedule	206	207	290	291	293	294*	295*	296*	299
4	x	x	x	x					x
5	x	x	x	x					x
15	x	x	x	x		x			x
23	x	x	x	x		x			x
28	x	x	x	x		x			x
30	x	x	x	x		x			x
41	x	x	x	x		x			x
47	x	x	x	x		x			x
48	x	x	x	x		x			x
51	x	x	x	x		x			x
53	x	x	x	x		x			x
54	x	x	x	x		x			x
60			x						
723	x	x	x	x		x			x
728	x	x	x	x		x			x
730	x	x	x	x		x	x	x	x
741	x	x	x	x		x			x
747	x	x	x	x		x	x	x	x
748	x	x	x	x		x	x	x	x
751	x	x	x	x		x			x
753	x	x	x	x		x			x
754	x	x	x	x		x			x
848			x	x	x				

(D)

(D)

*Not applicable to all consumers. See Schedule for details.

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 91

Purpose

The purpose of this Schedule is to collect funds for electric low-income bill payment assistance as specified in Oregon Laws 2021, Ch. 536, §2.

Applicable

To all bills for electric service calculated under all tariffs and contracts.

Adjustment Rates

The applicable Adjustment Rates are listed below. Retail electricity Consumers shall not be required to pay more than $500 per month per site for low-income electric bill payment assistance.

Schedule	Adjustment Rate
Residential Rate Schedules (4, 5)	$0.69 per month
Nonresidential Rate Schedules	0.069 cents per kWh for the first 724,638 kWh

(D)

Definition of Site (Order No. 01-073 entered January 3, 2001)

"Site" means:

(a) Buildings and related structures that are interconnected by facilities owned by a single retail electricity consumer and that are served through a single electric meter; or

(b) A single contiguous area of land containing buildings or other structures that are separated by not more than 1,000 feet, such that:

i. Each building or structure included in the site is no more than 1,000 feet from at least one other building or structure in the site;

ii. Buildings and structures in the site, and land containing and connecting buildings and structures in the site, are owned by a single retail electricity consumer who is billed for electricity use at the buildings and structures; and

iii. Land shall be considered to be contiguous even if there is an intervening public or railroad right of way, provided that rights of way land, on which municipal infrastructure facilities exist (such as street lighting, sewerage transmission, and roadway controls), shall not be considered contiguous.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

Purpose

The purpose of this Schedule is, in accordance with ORS 757.695, to collect funds for the electric low-income discount as specified in Schedule 7. This discount is enabled by House Bill 2475 (2021 regular sessions) which modified ORS 757.230 to allow for differentiated rates for "low-income customers and other economic, social equity, or environmental justice factors that affect affordability for certain classes of utility customers." This adjustment schedule is implemented as an automatic adjustment clause as provided for in ORS 757.210.

Applicable

To all bills for electric service calculated under all tariffs and contracts.

Adjustment Rates

The applicable Adjustment Rates are listed below.

Schedule	Adjustment Rate
Residential Rate Schedules (4, 5)	$0.34 per month
Nonresidential Rate Schedules	0.038 cents per kWh for the first 5,000,000 kWh per month

(D)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 98

ADJUSTMENT ASSOCIATED WITH THE PACIFIC NORTHWEST ELECTRIC POWER PLANNING AND CONSERVATION ACT

All bills of qualifying residential customers on Schedules 4 and 5 shall have deducted an amount equal to the product of kilowatt-hours of use multiplied by the following cents per kilowatt-hour up to a maximum of 2,000 kilowatt-hours each month: (D)

0-2,000 kWh	0.876¢ per kWh

All bills to qualifying 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:

0.818¢ 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").

Incentive Amounts (continued)

Income Eligible Rebate

L2 Charger	Up to $1,500, capped at 100 percent of qualified costs
240 V Outlet Rebate	$500 rebate for installation of a 240 V outlet, capped at 100 percent of qualified costs

Income Eligibility
Low-income qualified customers demonstrate eligibility through participation in low-income programming, including the Oregon Energy Fund, Low Income Home Energy Assistance Program, or the Oregon Energy Assistance program. Information on these programs is available at: https://www.pacificpower.net/my-account/payments/bill-payment-assistance.html

Special Conditions

1. Residential Customers receiving a Standard Rebate will automatically be enrolled in the time-of-use option for Schedule 4 for a minimum of one year. (C)
2. Residential Customers receiving an Income-Eligible Rebate will have the option to enroll in the time-of-use option for Schedule 4. (C)
3. To be eligible for an incentive, Customers must submit a Program Administrator approved post-purchase application and meet all Program requirements.
4. Incentives will be available on a first come first served basis with an overall port and three-year program cap.
5. The Company and its agents reserve the right to inspect installations.
6. Applications may be subject to charger and per project caps.

Incentive Amounts

The Pilot will provide a one-time rebate for the purchase and installation of a qualified L2 EVSE:

Standard EVSE Installation Rebate	Up to $1,000 per port; capped at 6 charging ports and 75 percent of EVSE eligible costs paid
MUD Eligible EVSE Installation Rebate	Up to $4,500 per port; capped at 12 charging ports and 75 percent of EVSE eligible costs paid

Special Conditions

1. Small Nonresidential Customers would be required to enroll the time-varying rate option for (C)
   Schedule 23 for a minimum of one year. (C)
2. To be eligible for an incentive, Customers must submit a Program Administrator approved application(s), provide all required documentation, and receive pre-approval.
3. Equipment purchased or installed prior to receipt of the Company's pre-approval may not be eligible for incentives.
4. Incentives will be available on a first come first served basis with an overall port and three-year program cap.
5. Customers must consent to provide charger usage data.
6. The Company and its agents reserve the right to inspect installations.
7. Applications may be subject to charger and per project caps.

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 190

Purpose

The purpose of this schedule is to implement cost recovery related to the Company's wildfire mitigation plan automatic adjustment clause consistent with OAR 860-300-0080 and ORS 757.210 and Order No. 23-173.

Applicable

To all Residential and Nonresidential Consumers.

Monthly Billing

All bills calculated in accordance with Schedules contained in the presently effective Tariff will have applied an amount equal to the product of all kWh multiplied by the following applicable rate as listed by Delivery Service schedule.

Schedule 4	0.678 ¢ per kWh	(I)
Schedule 5	0.678 ¢ per kWh	
Schedule 15	3.612 ¢ per kWh	
Schedule 23, 723	0.760 ¢ per kWh	
Schedule 28, 728	0.309 ¢ per kWh	
Schedule 30, 730	0.211 ¢ per kWh	
Schedule 41. 741	0.841 ¢ per kWh	
Schedule 47, 747	0.134 ¢ per kWh	
Schedule 48, 748, 848	0.134 ¢ per kWh	
Schedule 51, 751	3.481 ¢ per kWh	
Schedule 53, 752	0.433 ¢ per kWh	
Schedule 54, 754	0.553 ¢ per kWh	(I)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 193

 (N)

Purpose
The purpose of this schedule is to collect revenues for the Catastrophic Fire Fund.

Applicable
To all Residential and Nonresidential Consumers.

Monthly Billing
All bills calculated in accordance with Schedules contained in the presently effective Tariff will have applied an amount equal to the product of all kWh multiplied by the following applicable rate as listed by Delivery Service schedule.

Schedule 4	0.764 ¢ per kWh
Schedule 5	0.764 ¢ per kWh
Schedule 15	3.749 ¢ per kWh
Schedule 23, 723	0.856 ¢ per kWh
Schedule 28, 728	0.392 ¢ per kWh
Schedule 30, 730	0.278 ¢ per kWh
Schedule 41. 741	1.043 ¢ per kWh
Schedule 47, 747	0.178 ¢ per kWh
Schedule 48, 748, 848	0.178 ¢ per kWh
Schedule 51, 751	3.540 ¢ per kWh
Schedule 53, 752	0.460 ¢ per kWh
Schedule 54, 754	0.578 ¢ per kWh

(N)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 200

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**	
4	All kWh, per kWh	2.613¢			(R)
5	All kWh, per kWh	2.613¢			(R)
					(D)
23, 723	First 3,000 kWh, per kWh	2.610¢	2.570¢		(R)
	All additional kWh, per kWh	1.938¢	1.908¢		(R)

(M) to
pg. 2

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 200

Monthly Billing (continued)

Delivery Service Schedule No.		**Delivery Voltage** Secondary	Primary	Transmission	
28, 728	All kWh, per kWh	2.445¢	2.371¢		(R)(M) from pg.1
29	All kWh, per kWh	2.445¢	2.445¢		(R)
30, 730	Demand Charge, per kW	$5.39	$5.24		(R)
	All kWh, per kWh	0.888¢	0.826¢		(R)
	Demand shall be as defined in the Delivery Service Schedule				
41, 741	All kWh	2.346¢	2.310¢		(R)
47/48, 747/748	Demand Charge, per kW of On-Peak Demand	$1.45	$1.52	$1.54	(R)
	Per kWh, On-Peak	1.989¢	1.991¢	1.908¢	(R)
	Per kWh, Off-Peak	1.989¢	1.991¢	1.908¢	(R)

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	$0.54	(R)
	Level 2	5,501-12,000	34	$0.97	(R)
	Level 3	12-001+	57	$1.62	(R)

(continued)

Monthly Billing (continued)

Delivery Service Schedule No.

51, 751	**Type of Lamp**	**LED Equivalent Lumens**	**Monthly kWh**	**Rate per Lamp**	
	Level 1	0-3,500	8	$0.21	(R)
	Level 2	3,501-5,500	15	$0.41	
	Level 3	5,501-8,000	25	$0.67	
	Level 4	8,001-12,000	34	$0.91	
	Level 5	12,001-15,500	44	$1.18	
	Level 6	15,501+	57	$1.53	(R)

53, 753	**Types of Luminaire**	**Nominal rating**	**Watts**	**Monthly kWh**	**Rate Per Luminaire**	
	High Pressure Sodium	5,800	70	31	$0.11	(R)
	High Pressure Sodium	9,500	100	44	$0.15	
	High Pressure Sodium	16,000	150	64	$0.22	
	High Pressure Sodium	22,000	200	85	$0.30	
	High Pressure Sodium	27,500	250	115	$0.40	
	High Pressure Sodium	50,000	400	176	$0.61	
	Metal Halide	9,000	100	39	$0.14	
	Metal Halide	12,000	175	68	$0.24	
	Metal Halide	19,500	250	94	$0.33	
	Metal Halide	32,000	400	149	$0.52	
	Metal Halide	107,800	1,000	354	$1.24	(R)
	Non-Listed Luminaire, per kWh				0.349¢	(R)

54, 754	Per kWh	0.439¢	(R)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 201

NET POWER COSTS
COST-BASED SUPPLY SERVICE

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Residential Consumers and Nonresidential Consumers who have elected to take Cost-Based Supply Service under this schedule or under Schedules 210, 211, 212, 213 or 247. This service may be taken only in conjunction with the applicable Delivery Service Schedule. Also applicable to Nonresidential Consumers who, based on the announcement date defined in OAR 860-038-275, do not elect to receive standard offer service under Schedule 220 or direct access service under the applicable tariff. In addition, applicable to some Large Nonresidential Consumers on Schedule 400 whose special contracts require prices under the Company's previously applicable Schedule 48T. For Consumers on Schedule 400 who were served on previously applicable Schedule 48T prices under their special contract, this service, in conjunction with Delivery Service Schedule 48, supersedes previous Schedule 48T.

Nonresidential Consumers who had chosen either service under Schedule 220 or who chose to receive direct access service under the applicable tariff may qualify to return to Cost-Based Supply Service under this Schedule after meeting the Returning Service Requirements and making a Returning Service Payment as specified in this Schedule.

Monthly Billing

The Monthly Billing shall be the Energy Charge, as specified below by Delivery Service Schedule.

Delivery Service Schedule No.		**Delivery Voltage**			
		Secondary	**Primary**	**Transmission**	
4	All kWh, per kWh	4.227¢			
	Optional TOU Adders				(N)
	plus per On-Peak kWh	14.270¢			
	plus per Off-Peak kWh (credit)	-3.790¢			

Schedule 4 Consumers may choose to participate in the Time-of-Use rate option which provides time varying rate adders. On-Peak hours are from 5 p.m. to 9 p.m., all days. Off-Peak hours are all remaining hours. (N)

		Secondary	**Primary**	**Transmission**	
5	All kWh, per kWh	4.227¢			
	Optional TOU Adders				(N)
	plus per On-Peak kWh	14.270¢			
	plus per Off-Peak kWh (credit)	-3.790¢			

Schedule 5 Consumers may choose to participate in the Time-of-Use rate option which provides time varying rate adders. On-Peak hours are from 5 p.m. to 9 p.m., all days. Off-Peak hours are all remaining hours. (N)

(D)

		Secondary	**Primary**	**Transmission**	
23	First 3,000 kWh, per kWh	4.218¢	4.090¢		
	All additional kWh, per kWh	3.127¢	3.033¢		
	Optional TOU Adders				(N)
	plus per On-Peak kWh	12.578¢	12.578¢		
	plus per Off-Peak kWh (credit)	-2.532¢	-2.532¢		

Schedule 23 Consumers may choose to participate in the Time-of-Use rate option which provides time varying rate adders. On-Peak hours are from 5 p.m. to 9 p.m., all days. Off-Peak hours are all remaining hours. (N)

(M) to pg. 2

(continued)

Monthly Billing (continued)

Delivery Service Schedule No.		Secondary	Delivery Voltage Primary	Transmission	
28	All kWh, per kWh	3.932¢	3.842¢		(M) from pg. 1
29	All kWh, per kWh	4.961¢	4.961¢		
	Plus per On-Peak kWh	13.014¢	13.014¢		(N)
	Plus per Off-Peak kWh (credit)	-2.532¢	-2.532¢		(I)

For Schedule 29, On-Peak hours are from 5 p.m. to 9 p.m., all days Off-Peak hours are all remaining hours. (C) (D)

		Secondary	Primary	Transmission	
30	All kWh, per kWh	3.856¢	3.843¢		
41	All kWh, per kWh	3.799¢	3.739¢		
	Optional TOU Adders				
	Plus per On-Peak kWh	12.030¢	12.030¢		(I)
	Plus per Off-Peak kWh (credit)	-2.696¢	-2.696¢		(I)

Schedule 41 Consumers may choose to participate in one of two Time-of-Use (TOU) rate options, Option A and Option B which provide time-varying rates in the Summer months of July, August and September. Consumers may choose to participate in Option A with On-Peak hours from 2 p.m. to 6 p.m. all days in Summer or Option B with On-Peak hours from 6 p.m. to 10 p.m. all days in Summer. Off-peak hours for each Option are all other Summer hours which are not On-Peak. All other months have no time-of-use periods or rate adders.

		Secondary	Primary	Transmission
47/48	Per kWh On-Peak	4.625¢	4.500¢	4.358¢
	Per kWh, Off-Peak	3.333¢	3.195¢	3.031¢

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.

15	Type of Lamp	LED Equivalent Lumens	Monthly kWh	Rate per Lamp
	Level 1	0-5,000	19	$1.00
	Level 2	5,001-12,000	34	$1.78
	Level 3	12,001+	57	$2.99

(continued)

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	All kWh, per kWh	0.000¢		
5	All kwh, per kWh	0.000¢		
6	All kWh, per kWh	0.000¢		
23, 723	First 3,000 kWh, per kWh	0.000¢	0.000¢	
	All additional kWh, per kWh	0.000¢	0.000¢	
28, 728	All kWh, per kWh	0.000¢	0.000¢	

CANCELED

(continued)

Energy Charge (continued)

Delivery Service Schedule No.		Secondary	Delivery Voltage Primary	Transmission
29	All kWh, per kWh	0.000¢	0.000¢	
30, 730	All kWh, per kWh	0.000¢	0.000¢	
41, 741	All kWh, per kWh	0.000¢	0.000¢	
47/48	Per kWh On-Peak	0.000¢	0.000¢	0.000¢
747/748	Per kWh, Off-Peak	0.000¢	0.000¢	0.000¢

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.

15	Type of Lamp	LED Equivalent Lumens	Monthly kWh	Rate per Lamp
	Level 1	0-5,000	19	$0.00
	Level 2	5,001-12,000	34	$0.00
	Level 3	12,001+	57	$0.00

CANCELED

(continued)

Energy Charge (continued)

Delivery Service Schedule No.

51, 751	Type of Lamp	LED Equivalent Lumens	Monthly kWh	Rate per Lamp
	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
	Level 4	8,001-12,000	34	$0.00
	Level 5	12,001-15,500	44	$0.00
	Level 6	15,501+	57	$0.00

53, 753	Types of Luminaire	Nominal rating	Watts	Monthly kWh	Rate Per Luminaire
	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
	High Pressure Sodium	22,000	200	85	$0.00
	High Pressure Sodium	27,500	250	115	$0.00
	High Pressure Sodium	50,000	400	176	$0.00
	Metal Halide	9,000	100	39	$0.00
	Metal Halide	12,000	175	68	$0.00
	Metal Halide	19,500	250	94	$0.00
	Metal Halide	32,000	400	149	$0.00
	Metal Halide	107,800	1,000	354	$0.00
	Non-Listed Luminaire, per kWh				0.000¢

54, 754 Per kWh 0.000¢

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 210

PORTFOLIO TIME-OF-USE SUPPLY SERVICE
CLOSED TO NEW SERVICE

 (N)

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. **This Schedule is closed to new service beginning January 1, 2025.** (N)

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.

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 November 1 through March 31. Summer months are defined as April 1 through October 31.

Minimum Charge

The minimum monthly charge will be the Portfolio Service Charge.

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)

Off-Peak Period

All non On-Peak Period plus the following holidays: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

Guarantee Payment

The Company shall guarantee against increase of consumer costs for the first 12 months of enrollment in the program. If the total annual energy costs incurred on this Schedule exceed 10% over what costs would have been for the same period under Cost-Based Supply Service, the net difference, Guarantee Payment, will be credited on the customer's bill following the last month of the one-year commitment. No Guarantee Payment shall be given if Consumer terminates service before the end of the initial one-year period.

Special Conditions

1. The Consumer shall not resell electric service received from the Company under provisions of this Schedule to any person, except by written permission of the Company or as otherwise expressly provided in Company tariffs and where the Consumer meters and bills any of its tenants at the Company's regular tariff rate for the type of service which such tenant may actually receive.

2. The Company will recover any lost revenues and Guarantee Payment amounts incurred under the Portfolio Option through adjustment schedules.

3. Consumers on this tariff schedule shall have a term of not less than one year. Service will continue under this schedule until Consumer notifies the Company to discontinue service.

4. The Consumer must have a time-of-use meter installed to participate in this option. The Company anticipates that a delay may occur from the time a Consumer requests service under this option until the Company can provide the meter installation. In the interim, Consumers will receive service under the applicable Delivery Service schedule on Supply Service Schedule 201.

5. Billing under this schedule shall begin for the Consumer following installation of the time-of-use meter and the initial meter reading.

6. The Company will not accept enrollment for accounts that have:

   - Time-payment agreement in effect
   - Received two or more final disconnect notices
   - Been disconnected for non-payment within the last 12 months.

7. Service under this schedule will be labeled, "Time of Use".

8. Consumers taking service under this Schedule will be removed from time-of-use on June 1, (N)
   2025. The Consumer must notify the Company to enroll in a different time-of-use option. (N)

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.

Available

In all territory served by the Company in the State of Oregon.

Applicable

To New Large Load for Nonresidential Consumers taking Delivery Service under Schedule 848 who have chosen to opt-out of the Company's Cost-Based Supply Service prior to the inception of electric service to the New Large Load. Consumer must officially notify the Company of its election for this program in accordance with Rule 22 of this tariff. New Large Load must be separately metered or have its usage measured based on a determination that has comparable accuracy and is mutually agreeable between the Company and the Consumer.

Total Eligible Load

A total of 89 aMW will be accepted under this program unless the Commission determines otherwise.

Administration Fee

Consumers taking service under this program will pay the following program Administration Fee:
$400 per month

Fixed Generation Transition Adjustment

A transition adjustment of 20 percent of fixed generation rates will be charged for the first five years of service to the Consumer under this program beginning when the Consumer's electric service is first energized. Fixed generation rates include Schedule 200, Base Supply Service rates along with any other rates which collect non-net power cost generation costs that are in effect during the five year transition period for each Consumer. The adjustment will be applied at 20 percent of the rates included in the Company's effective tariffs applicable to Delivery Service Schedule 48. At the end of the applicable five-year period, Consumers who have elected this option will no longer be subject to the fixed generation transition adjustment.

List of effective schedules with fixed generation rates which will incur a 20 percent Fixed Generation Transition Adjustment:
Schedule 200, Base Supply Service
Schedule 198, Deer Creek Mine Closure Deferred Amounts Adjustment
Schedule 203, Renewable Resource Deferral Adjustment
Schedule 204, Oregon Solar Incentive Program Deferral (D)
Schedule 207, Community Solar Start-Up Cost Recovery Adjustment

Existing Load Shortage Transition Adjustment

The Existing Load Shortage Transition Adjustment will be applied to the Existing Load Shortage of the Consumer and for the Existing Load Shortage for all of the Consumer's affiliated Consumers. An affiliated Consumer is a Consumer for which a controlling interest is held by another Consumer who is engaged in the same line of business as the holder of the controlling interest. Existing Load Shortage means the larger of zero or a Consumer's Average Historical Cost-of-Service Load plus Incremental Demand-Side Management less the average Cost-of-Service Eligible load during the previous 60 months. Average Historical Cost-of-Service Load means the average monthly Cost-of-Service Eligible Load during the 60 month period beginning five years prior to the date the Consumer gives binding notice of participation in this program.

(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.

(C)

Schedule 4	0.000¢
Schedule 5	0.000¢
Schedule 15	3.900¢
Schedule 23, 723	(0.360¢)
Schedule 28, 728	0.324¢
Schedule 30, 730	0.324¢
Schedule 41, 741	(3.168¢)
Schedule 47, 747	0.000¢
Schedule 48, 748	0.000¢
Schedule 51, 751	5.150¢
Schedule 53, 753	1.260¢
Schedule 54, 754	1.840¢

(C)

Service Charges (continued)

Rule No.	Sheet No.	Description	Charge	
11B	R11B-5	**Tampering/Unauthorized Reconnection**	$75.00	
11D	R11D-7	**Non-Remote Service Connection Charge:**		
		Request for reconnect during regular business hours: Monday through Friday, except holidays 8:00 A.M. to 5:00 P.M.	No Charge	
		Request for reconnect during non-regular business hours: Monday through Friday, except holidays 5:00 P.M. to 6:00 P.M.	$75.00	
		Saturday, Sunday & Holidays 8:00 A.M. to 6:00 P.M.	$175.00	
		Remote Service Connection Charge:	No Charge	
11D	R11D-7	**Trouble Call Charge:**	Actual Costs May Be Charged	
11D	R11D-7	**Other Work at Consumer's Request:**	Actual Costs May Be Charged	
13	R13-1	**Capacity Reservation Charge:**	$4.91 per kW	(N)
13	R13-2	**Excess Demand Charge:**	$19.64 per kW	(N)
13	R13-2	**Facilities Charges:**		
		On Facilities at Less than 57,000 Volts		
		Installed at Consumer's expense	0.4% per month	
		Installed at Company's expense	1.2% per month	
		On Facilities at and above 57,000 Volts		
		Installed at Consumer's expense	0.2% per month	
		Installed at Company's expense	0.85% per month	
13	R13-11	**Temporary Service Charge:**		
		Service Drop and Meter only	$164.00	
13	R13-13	**Contract Administration Credit**	$250.00	
21	R21-3	**Pre-Enrollment Usage Information:**		
		Bill Register History per Meter	$2.00 per year	
		Validated Interval Data (15 – 60 minute) per Meter	$10.00 per month	
		Analyzed Interval Meter Data	Cost Based Price	
21	R21-3	**Pre-Enrollment Payment History:**	$2.00 per page	

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 723

GENERAL SERVICE – SMALL NONRESIDENTIAL
DIRECT ACCESS DELIVERY SERVICE

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	$22.10	$22.10	(I)
Three Phase, per month	$32.95	$32.95	(I)
Load Size Charge			
≤ 15 kW	No Charge	No Charge	
> 15 kW, per kW for all kW in excess of 15 kW, Load Size	$ 2.10	$ 2.10	(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	$ 6.87	$ 6.78	(I)
Distribution Energy Charge, per kWh	5.080¢	5.001¢	(I)
Reactive Power Charge, per kvar	$ 0.65	$ 0.60	
System Usage Charge			
Schedule 200 Related, per kWh	0.064¢	0.063¢	(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.

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	$ 25.00	$ 35.00	(I)
Load Size 51-100 kW, per month	$ 47.00	$ 60.00	(I)
Load Size 101 - 300 kW, per month	$111.00	$138.00	(I)
Load Size > 300 kW, per month	$156.00	$197.00	(I)
Load Size Charge			
≤ 50 kW, per kW Load Size	$ 1.60	$ 1.95	(I)
51-100 kW, per kW Load Size	$ 1.25	$ 1.55	
101 – 300 kW, per kW Load Size	$ 0.75	$ 0.95	
> 300 kW, per kW Load Size	$ 0.50	$ 0.50	
Demand Charge, per kW	$ 5.31	$ 6.78	
Distribution Energy Charge, per kWh	0.536¢	0.103¢	(I)
Reactive Power Charge, per kvar	$ 0.65	$ 0.60	
System Usage Charge			
Schedule 200 Related, per kWh	0.067¢	0.060¢	(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.

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.

<u>**Distribution Charge**</u>	<u>**Delivery Voltage**</u>		
	Secondary	**Primary**	
Basic Charge			
Load Size ≤ 200 kW, per month	$704.00	$642.00	(I)
Load Size 201 - 300 kW, per month	$204.00	$202.00	(I)
Load Size > 300 kW, per month	$541.00	$527.00	(I)
Load Size Charge			
≤ 200 kW, per kW Load Size	No Charge	No Charge	
201 – 300 kW, per kW Load Size	$ 2.50	$ 2.20	(I)
> 300 kW, per kW Load Size	$ 1.20	$ 1.10	(I)
Demand Charge, per kW	$ 5.92	$ 5.59	(I)
Reactive Power Charge, per kvar	$ 0.65	$ 0.60	
<u>**System Usage Charge**</u>			
Schedule 200 Related, per kWh	0.065¢	0.065¢	(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.

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)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 741

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	$ 580.00	$ 570.00	(I)
Three Phase Load Size > 300 kW	$2,300.00	$2,270.00	(I)
Load Size Charge (November billing only)			
Single Phase Any Size, Three Phase ≤ 50 kW, per kW Load Size	$ 24.20	$ 23.90	(I)
Three Phase 51 - 300 kW, per kW Load Size	$ 16.60	$ 16.40	(I)
Three Phase > 300 kW, per kW Load Size	$ 10.20	$ 10.10	(I)
Single Phase, Minimum Charge	$ 105.00	$ 105.00	(I)
Three Phase, Minimum Charge	$ 170.00	$ 170.00	(I)
Distribution Energy Charge, per kWh	7.049¢	6.940¢	(I)
Reactive Power Charge, per kVar	$ 0.65	$ 0.60	
System Usage Charge			
Schedule 200 Related, per kWh	0.058¢	0.057¢	(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 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	$820.00	$1,160.00	$1,770.00	(I)
Facility Capacity > 4,000 kW, per month	$2,260.00	$3,190.00	$4,550.00	(I)
Facilities Charge				
≤ 4,000 kW, per kW Facility Capacity	$2.60	$1.35	$1.35	(R)(I)(I)
> 4,000 kW, per kW Facility Capacity	$1.00	$0.55	$1.15	(R)(I)(I)
On-Peak Demand Charge, per kW	$6.42	$7.95	$6.21	(I)
Reactive Power Charges				
Per kVar	$0.65	$0.60	$0.55	
Per kVarh	$0.0008	$0.0008	$0.0008	
Customer Funded Substation Credit, per kW Facility Capacity	N/A	-$1.50	N/A	(N) (N)
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	0.066¢	0.061¢	0.059¢	

(continued)

On-Peak Demand

The kW shown by or computed from the readings of the Company's demand meter for the On-Peak 15-minute period of the Consumer's greatest use during the month, determined to the nearest kW. 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.

Customer Funded Substation (N)

A Consumer will receive the Customer Funded Substation Credit if they take distribution voltage service, have a load size of 25,000 kW or greater, and received an Extension Allowance that was equal to the metering necessary to measure their usage. (N) (N) (N)

Metering Adjustment

A Consumer receiving service at secondary delivery voltage where metering is at primary delivery shall have all billing quantities multiplied by an adjustment factor of 0.9845.

A Consumer receiving service at primary delivery voltage where metering is at secondary delivery voltage shall have all billing quantities multiplied by an adjustment factor of 1.0157.

Baseline Demand

The kW of Demand supplied by the Company to the Large Nonresidential Consumer when the Consumer's generator is regularly operating as planned by the Consumer. For new Partial Requirements Consumers, the Consumer's peak Demand for the most recent 12 months prior to installing the generator, adjusted for planned generator operations, shall be used to calculate the Baseline Demand. Existing Partial Requirements Consumers shall select their Baseline Demand for each contract term based upon the Consumer's peak demand for the most recent 12 months during the times the generator was operating as planned, adjusted for changes in load and planned generator operations. Planned generator operations includes changes in the electricity produced by the generator as well as the Consumer's plans to sell any electricity produced by the generator to the Company or third parties. Any modification to the Baseline Demand must be consistent with Special Conditions in this schedule.

Facility Capacity

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, but shall not be less than the Consumer's Baseline Demand. For new customers during the first three months of service under this schedule, the Facility Capacity will be equal to the Consumer's Baseline Demand.

Reserves Charges

The Company provides Reserves for the Consumer's Facility Capacity. Reserves consist of the following components:

Spinning Reserves

In addition to the Spinning Reserves provided for the Consumer's Baseline Demand, Spinning Reserves provide Electricity immediately after a Consumer's demand rises above Baseline Demand.

(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.

<u>Distribution Charge</u>		<u>Delivery Voltage</u>		
	Secondary	**Primary**	**Transmission**	
Basic Charge				
Facility Capacity ≤ 4000 kW, per month	$820.00	$1,160.00	$1,770.00	(I)
Facility Capacity > 4000 kW, per month	$2,260.00	$3,190.00	$4,550.00	(I)
Facilities Charge				
≤ 4000 kW, per kW Facility Capacity	$2.60	$1.35	$1.35	(R)(I)(I)
> 4000 kW, per kW Facility Capacity	$1.00	$0.55	$1.15	(R)(I)(I)
On-Peak Demand Charge, per kW	$6.42	$7.95	$6.21	(I)
Reactive Power Charge, per kvar	$0.65	$0.60	$0.55	
Customer Funded Substation Credit, per kW Facility Capacity	N/A	-$1.50	N/A	(N) (N)
<u>**System Usage Charge**</u>				
Schedule 200 Related, per kWh	0.066¢	0.061¢	0.059¢	(R)

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)

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.

On-Peak Demand

The kW shown by or computed from the readings of the Company's demand meter for the On-Peak 15-minute period of the Consumer's greatest use during the month, determined to the nearest kW. 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.

Customer Funded Substation (N)

A Consumer will receive the Customer Funded Substation Credit if they take distribution voltage (N)
service, have a load size of 25,000 kW or greater, and received an Extension Allowance that (N)
was equal to the metering necessary to measure their usage. (N)

Metering Adjustment

For a Consumer receiving service at secondary delivery voltage where metering is at primary delivery shall have all billing quantities multiplied by an adjustment factor of 0.9845.

For a consumer receiving service at primary delivery voltage where metering is at secondary delivery voltage shall have all billing quantities multiplied by an adjustment factor of 1.0157.

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 not resell electric service received from Company under provisions of this Schedule to any person, except by permission of the Company or as otherwise expressly provided in Company tariffs.

Term of Contract

Company may require the Consumer to sign a written contract which shall have a term of not less than one year.

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 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	$ 6.50	$ 6.88	$ 6.99	$ 7.10	$ 7.52	$ 9.17	(I)
Functional Lighting - Customer Funded Conversion	$ 3.50	$ 3.68	$ 3.78	$ 3.84	$ 4.08	$ 5.01	(I)
Decorative Series	N/A	$ 11.88	$ 11.97	N/A	N/A	N/A	(I)

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)

Issued February 14, 2024
Matthew McVee, Vice President, Regulation
Effective for service on and after January 1, 2025
Advice No. 24-001/Docket No. UE 433

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	$ 1.31	$ 1.86	$ 2.70	$ 3.58	$ 4.85	$ 7.42

(I)

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	$ 1.64	$ 2.87	$ 3.96	$ 6.28	$ 14.93

(I)

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	4.217

(I)

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)

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	4.684¢	(I)
System Usage Charge		
Schedule 200 Related, per kWh	0.012¢	(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.

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 776R

LARGE GENERAL SERVICE - PARTIAL REQUIREMENTS SERVICE-ECONOMIC REPLACEMENT SERVICE RIDER DIRECT ACCESS DELIVERY SERVICE

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	$0.250	$0.310	$0.242	(I)

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

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.

<u>Distribution Charge</u>		<u>Delivery Voltage</u>		
	Secondary	**Primary**	**Transmission**	
Basic Charge				
Facility Capacity ≤ 4000 kW, per month	$820.00	$1,160.00	$1,770.00	(I)
Facility Capacity > 4000 kW, per month	$2,260.00	$3,190.00	$4,550.00	(I)
Facilities Charge				
≤ 4000 kW, per kW Facility Capacity	$2.60	$1.35	$1.35	(R)(I)(I)
> 4000 kW, per kW Facility Capacity	$1.00	$0.55	$1.15	(R)(I)(I)
On-Peak Demand Charge, per kW	$6.42	$7.95	$6.21	(I)
Reactive Power Charge, per kvar	$0.65	$0.60	$0.55	
Customer Funded Substation Credit, per kW Facility Capacity	N/A	-$1.50	N/A	(N)(N)

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)

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.

On-Peak Demand

The kW shown by or computed from the readings of the Company's demand meter for the On-Peak 15-minute period of the Consumer's greatest use during the month, determined to the nearest kW. 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.

Customer Funded Substation (N)

A Consumer will receive the Customer Funded Substation Credit if they take distribution voltage (N)
service, have a load size of 25,000 kW or greater, and received an Extension Allowance that (N)
was equal to the metering necessary to measure their usage. (N)

Metering Adjustment

For a Consumer receiving service at secondary delivery voltage where metering is at primary delivery shall have all billing quantities multiplied by an adjustment factor of 0.9845.

For a consumer receiving service at primary delivery voltage where metering is at secondary delivery voltage shall have all billing quantities multiplied by an adjustment factor of 1.0157.

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 distribution charges are collected through distribution charges.

Special Conditions

Consumer shall not resell electric service received from Company under provisions of this Schedule to any person, except by permission of the Company or as otherwise expressly provided in Company tariffs.

Term of Contract

Company may require the Consumer to sign a written contract which shall have a term of not less than one year.

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.

Definitions (continued)

Customer: Any individual, partnership, corporation, firm, other organization or government agency who has applied for, been accepted and is currently receiving service from the Company at one location and at one point of delivery unless otherwise expressly provided in these rules, or in a rate schedule or contract. Any individual requesting service who has been a Customer within the last 20 days and voluntarily closed their account at the same or prior address. A Customer may not resell Electricity Services provided by the Company except as provided for in Company Tariffs.

Cost-Based Service: Has the meaning described in Rule 2, "Types of Service."

Cost-of-Service Eligible Load: as defined in OAR 860-038-0700, the load of a Consumer that is eligible for a cost-of-service rate.

Date of Presentation: The date upon which a bill is mailed, transmitted or delivered by the Company to the Consumer.

Delivery Service: Regulated distribution, transmission and related services provided using assets owned by the Company or its agent.

Delivery Voltage: Secondary Delivery Voltage is service delivery at less than the locally available distribution voltage, and is typically less than 11kV phase-phase. Primary Delivery Voltage is service delivery at the locally available distribution voltage, which is typically 11kV phase-phase or greater. Transmission Delivery Voltage is 46kV and greater. (C)(D)

Demand: The average rate in kilowatts at which electric energy is delivered during any period of time for specified length.

Detented: The condition of an electric meter which has a device installed to prevent reverse rotation or negative registration of the meter if electric current flows from Consumer's to Company's system.

Direct Access Consumer: A Consumer that purchases Electricity Services from an ESS.

Direct Access Service: Has the meaning described in Rule 2, "Types of Service."

Duplicate Service Facilities: Two services, including all associated distribution facilities, one duplicating part or all of the capacity of the other and providing a second possible path of supply of energy in the event of the failure of the first.

Electric Service: Electric power and energy at the point of delivery available for use by Consumer, irrespective of whether electric energy is actually utilized.

Electricity: Electric energy, measured in kilowatt-hours, or electric capacity measured in kilowatts, or both.

Electricity Services: Electricity distribution, transmission, generation or generation-related services.

Electricity Service Supplier or "ESS": A person or entity that offers to provide Electricity Services, certified by the Commission to provide such services, and meeting the requirements for service specified in Section IV of Rule 21. "Electricity Service Supplier" does not include the Company selling electricity to Consumers in its own service territory.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

I. Line Extensions - Conditions and Definitions

A. Capacity Reservation Charge (N)
Beginning July 1, 2025, the Company may charge Consumers a Capacity Reservation Charge for Excess Reserved Capacity. The Capacity Reservation Charge is specified in Schedule 300. (N)

B. Contracts (T)
Before building an Extension, the Company may require the Applicant to sign a contract. Where a tenant occupies the service location, the Company may require the property owner to sign the contract.

C. Contract Minimum Billing (T)
The Contract Minimum Billing is the greater of: (1) the Consumer's monthly bill; or, (2) 80% of the Consumer's monthly bill plus the Facilities Charges. Consumers on a seasonal rate receive an annual Contract Minimum Billing of the greater of: (1) the Consumer's annual bill; or, (2) 80% of the Consumer's annual bill plus the Annual Facilities Charge. The Annual Facilities Charge is twelve (12) times the Facilities Charges. Contract Minimum Billings begin on the date service is first made available by the Company, unless a later date is mutually agreed upon.

For Consumers electing Standard Offer or Direct Access Service, the charges for Supply Service, ESS charges and the Transition Adjustment are excluded from the Consumer's bill before calculating the Contract Minimum Bill. For these Consumers the Contract Minimum Billing is the greater of: (1) the Consumer's monthly bill; or, (2) 60% of the Consumer's monthly bill plus the Facilities Charges. Consumers on a seasonal rate receive an annual Contract Minimum Billing of the greater of: (1) the Consumer's annual bill; or, (2) 60% of the Consumer's annual bill plus the Annual Facilities Charge.

D. Direct Assigned Facilities (T)
Direct Assigned Facilities are those required facilities located between existing Company network facilities and the Consumer's point of delivery, and used for the sole use and benefit of the Consumer receiving service under the tariff and are owned and operated by the Company.

Extensions consisting of Direct Assigned Facilities are made at the Consumer's expense less their applicable Extension Allowance as provided in this Rule 13.

E. Engineering Costs (T)
The Company includes designing, engineering and estimating in its Extension Costs. The Company may require the Applicant to advance the Company's estimated Engineering Costs, but not less than $200. The Company will apply this advance payment to its Extension Costs. If, after applying the Extension Allowance, it is determined that the total advance required is less than the advance already received, the excess will be refunded to the Applicant.

If the Applicant or Consumer requests changes that require additional estimates, they must advance the Company's estimated Engineering Costs, but not less than $200 for each additional estimate. The Company will not refund or credit this payment.

(M) to pg. 2

(continued)

I. Line Extensions - Conditions and Definitions (continued)

F. Excess Demand Charge (N)

Beginning July 1, 2025, Consumers whose maximum recorded and billed demand exceeds their Reserved Capacity may be charged an Excess Demand Charge. The Excess Demand Charge is specified in Schedule 300.

G. Excess Reserved Capacity

Reserved Capacity, less the maximum recorded and billed Consumer demand in the most recent 12 months. Excess Reserved Capacity shall begin 12 months after the time Reserved Capacity commences.

The Company's tracking of Excess Reserved Capacity shall begin 36 months after the agreed upon capacity delivery date for Consumers who have executed a written Line Extension Contract prior to January 1, 2025. For Consumers who have executed a written Line Extension Contract prior to January 1, 2025, Excess Reserved Capacity shall be Reserved Capacity, less the maximum recorded and billed Consumer demand in the most recent 36 months. (N)

H. Extension or Line Extension (T)(M) from pg. 1

A branch from, a continuation of, or an increase in the capacity of an existing Company-owned transmission or distribution line. An extension may be single-phase, three-phase, or a conversion from a single-phase line to a three-phase line. An extension may also be the addition of, or increase in the capacity of other facilities. (M)

I. Extension Allowance (T)

The Extension Allowance is the portion of the Extension that the Company may provide, or allow, without cost to the Applicant. The portion will vary with the class of service that the Applicant requests and the Applicant's total load request, and shall not exceed the Extension Costs.

The Extension Allowance does not include additional costs resulting from: additional voltages; duplicate facilities; additional points of delivery; or any other Applicant requested facilities that add to, or substitute for, the Company's standard construction methods or preferred route. The Extension Allowance is not available to Consumers receiving electric service under special pricing contracts. Revenue used for calculating Extension Allowances will exclude charges and credits for Supply Service, ESS Charges and the Transition Adjustment.

J. Extension Costs (T)

Extension Costs are the Company's total costs for constructing an Extension using the Company's standard construction methods, including services, transformers and meters, labor, materials and overhead charges.

K. Extension Limits (T)

The provisions of this Rule apply to Line Extensions that require standard construction and will produce sufficient revenues to cover the ongoing costs associated with them. The Company will construct Line Extensions with special requirements or limited revenues under the terms of special contracts.

Examples of special requirements include, but are not limited to, unusual costs incurred for overtime wages, use of special equipment and facilities, accelerated work schedules to meet the Applicant's request, or non-standard construction requirements. (M) to pg. 3

(continued)

I. Line Extensions - Conditions and Definitions (continued)

K. Extension Limits (continued)

Examples of limited revenues include, but are not limited to, jobs where the line extension cost is high relative to the revenue, speculative loads and service to loads that will not have permanent ongoing revenue. (N) (N) (N)

L. Facilities Charges (T)(M) from pg. 2

Line Extension Facilities Charges are those costs associated with the ownership and maintenance of facilities built to provide service. When assessed these Facilities Charges are in addition to standard rate schedule charges and are specified in Schedule 300.

M. Network Upgrades (T)

Network Upgrades are modifications or additions to existing Company facilities required to serve load that is requested by an Applicant and are integrated with and support the Company's overall transmission and distribution network(s) for the general benefit of all users of such network(s). However requests to change the nature of an existing line, such as rebuilding from single-phase to three-phase, will be treated as Direct Assigned Facilities for cost allocation purposes. Other than on low-voltage secondary network systems (≤ 750 volts), distribution transformers and secondary cable are not network facilities and are treated as Direct Assigned Facilities for cost allocation purposes.

Network Upgrades of transmission facilities of 230 kV and above and utilized and defined as a transmission path, or facilities that are on the Western Electric Coordinating Council (WECC) critical path list, and associated substations, will be made at Company expense. (M)

Network Upgrades on systems not exempted above are made as follows:

1. Distribution Networks greater than 750 volts

   a. Upgrades for Consumers with total loads of 1000 kVA or less will be made at Company expense.

   b. Upgrades for Consumers with total loads in excess of 1000 kVA will share in the Network Upgrade cost. The Consumer's share of the required Network Upgrade cost is proportional to the amount of the new requested load divided by the sum of the total capacity of the required Network Upgrade less the existing load on the existing network facility.

2. Upgrades for Consumers on low-voltage network systems (≤ 750 volts) will share in the Network Upgrade costs. The Consumer's share will be proportional to the new requested load in kVA divided by the total kVA capacity of the required Network Upgrade. Total kVA capacity is defined by the single Network element (transformer, primary cable, or secondary cable) with the largest kVA increase in capacity.

If the Extension Allowance of a Consumer who shares in the cost of a Network Upgrade does not cover their proportionate share of the Network Upgrade cost, they shall pay a nonrefundable advance of the difference.

(M) to pg. 4

(continued)

I. Line Extensions - Conditions and Definitions (continued)

N. Refunds (T)(M) from (N) pg. (N) 3

An Applicant who pays a refundable advance on an Extension is eligible for up to three refunds during the first five years. Customers requiring 25,000 kw or greater are eligible for up to three refunds during the first ten years. Within that five-year or ten-year period the Applicant may waive any refund that is less than 25% of the Applicant's total refundable advance in order to accept three (3) refunds offering greater value. An Applicant is not eligible for refunds from future Extension applications from themselves.

For non-waived refunds the additional Applicants must pay the Company, prior to connection, as provided in the section for the original Applicant. The Company will refund such payments to the Applicant(s) who paid the refundable advance. The Company will not collect from additional Applicants any portion of a waived refund.

An Applicant to who a refund is due, but who the Company has failed to identify or has been unable to locate, has 36 months from the connection of the additional Applicant to request their refund. (M)

O. Reserved Capacity (N)

Capacity reserved for a Consumer as specified in written agreements. (N)

P. Restrictions (T)(M) from pg.3

An Extension of the Company's facilities is subject to these rules and other rules and restrictions. These may include, but are not limited to: laws of the United States; State law; executive and administrative proclamations; Commission orders or regulations; or, any lawful requirement of a governmental body. (M)

Q. Routes, Easements and Rights-of-Way (T)

The Company will select the route of an Extension in cooperation with the Applicant. The Applicant will acquire and pay all costs, including renewal costs, of obtaining complete unencumbered rights-of-way, easements, or licenses to use land, and will pay all costs for any preparation or clearing of land the Company may require. All rights-of-way, easements or licenses shall be on Company-provided standard forms, subject to revisions acceptable to the Company, and shall not include indemnification of the Applicant. If requested by the Applicant, the Company will assist in obtaining rights-of-way, easements or licenses as described above at the Applicant's expense.

(T)

R. Rules Previously in Effect

Rule changes do not modify existing Extension contracts. If a Consumer advanced funds for an Extension under a rule or a contract previously in effect, the Company will make refunds for additional Consumers as specified in the previous rule or contract.

(T)

S. Service Conductors

The secondary-voltage conductors owned and maintained by the Company extending from the Company's facility to the Point of Delivery.

(M) to pg. 5

(continued)

II. Residential Extensions

A. Extension Allowances (M) from Pg. 4

The Extension Allowance for permanent residential applications is $1100 per residence. The Extension Allowance for permanent residential applications in a planned development with secondary to the lot line is $500, otherwise it is $1100. The Applicant must advance the costs exceeding the Extension Allowance prior to the start of construction.

B. Additional Applicants, Advances and Refunds

A Consumer that pays for a portion of the construction of an Extension may receive refunds if additional Applicants connect to the Extension. The Consumer is eligible for refunds during the first five (5) years following construction of an Extension for up to three (3) additional Applicants as given in section I.K. Refunds. Each of the next three (3) Applicants for which refunds are not waived, utilizing any portion of the initial Extension must pay the Company, prior to connection, 25% of the cost of the shared facilities. The Company will refund such payments to the initial Consumer.

C. Remote and Seasonal Service

1. Contracts

The Company will make Extensions for Remote and Seasonal Residential Service according to a written contract. The contract will require the Applicant to advance the estimated cost of facilities in excess of the Extension Allowance. The Applicant shall also pay a Contract Minimum Billing for as long as service is taken, but in no case less than five (5) years. Primary residences are not Remote when the density of such residences exceeds one residence per one-half mile of line. Facilities Charges will cease when Consumers are no longer Remote. (M)

The Contract Minimum Billing will not include Facilities Charges on the first one-half mile of line from the Company's existing distribution facilities. Where there are groups of remote facilities only the first one-half mile is exempt from Facilities Charges.

After the initial five year contract period, Remote Service Contract Minimum Billings may be canceled by termination of electric service to the Consumer's premises and Consumer payment of the removal costs of those inactive facilities originally installed to serve the Consumer.

2. Additional Applicants

During the first five years after the Company completes the Extension, each of the next three Applicants must pay an allocated share of the original Consumer's contribution. The Company will determine these shares taking into account: (a) how much of the original line the new Applicant shares; (b) the load sizes of the Applicant and the existing Consumers; and (c) the advances of the existing Consumers. The Applicant must pay this allocated share before the Company will provide service. The Company will refund this share to the existing Consumers.

(M) to pg. 6

(continued)

II. Residential Extensions (continued)

C. Remote and Seasonal Service (continued)

2. Additional Applicants (continued)

Additional Applicants also must also share the Facilities Charges of the existing Consumers. The Facilities Charges of the refund are allocated to the Applicant paying the refund. (M) from pg. 5

The Applicant also must pay the estimated cost of any facilities exceeding the Extension Allowance.

D. Three Phase Residential Service

Where three-phase residential service is requested, the Applicant shall pay the difference in cost between single phase and three-phase service.

E. Transformation Facilities

When an existing residential Consumer adds load, or a new residential Consumer builds in a subdivision where secondary is available at the lot line, either by the means of a transformer or a secondary junction box, and the cumulative loads exceed the existing transformer's, service conductor's or other equipment's rated design capacity:

1) The facility upgrade will be treated as a standard line extension if the Consumer's demand exceeds 25 kVA, or if the facilities serve only that Consumer.

2) The facility upgrade shall be treated as a system improvement and not be charged to the Consumer if the Consumer's demand does not exceed 25 kVA and the facilities are shared by two or more consumers.

Upgrades and modifications to correct service quality issues such as flicker are done at the expense of the Consumer causing the service quality issue. (M)

F. Underground Extensions

The Company will construct Extensions underground when requested by the Applicant or if required by local ordinance or conditions. The Applicant shall provide all trenching and back filling, imported backfill material, conduits, and equipment foundations that the Company requires for the Extension. If the Applicant requests, the Company will provide these items at the Applicant's expense. The Applicant must also pay for the conversion of any existing overhead facilities to underground, under the terms of Section VI of this Rule.

III. Nonresidential Extensions

A. Extension Allowance – Delivery at Transmission Voltage

The Company will grant Consumers taking service at 46,000 volts or above an Extension Allowance of the metering necessary to measure the Consumer's usage. (C)
Other than the allowance, Consumers taking delivery at transmission voltage are subject to the same line extension provisions as a Consumer requiring more than 1000 kW who takes service at less than 46,000 volts. (C)

B. Extension Allowance – Delivery at Secondary or Primary Voltage

1. 1,000 kW or less

The Company will grant Nonresidential Applicants requiring 1,000 kW or less an Extension Allowance equal to the estimated annual revenue the Applicant is expected to pay the Company in a year of normal operations under cost-based service. The Applicant must advance the costs exceeding the Extension Allowance prior to the start of construction. (M) to pg. 7

(continued)

III. Nonresidential Extensions (continued)

B. Extension Allowance – Delivery at Secondary or Primary Voltage (continued)

1. 1,000 kW or less (continued) (M) from pg. 6

The Company may require the Consumer to pay a Contract Minimum Billing for five years. If the Consumer is Remote they shall pay a Contract Minimum Bill for as long as service is taken, or until they no longer meet the criteria for Remote Service.

2. Over 1,000 kW and Less than 25,000 kW

The Company will grant Nonresidential Applicants requiring more than 1,000 kW but less than 25,000 kW an Extension Allowance equal to the estimated annual revenue which the Applicant is expected to pay the Company in a year of normal operations under cost-based service. The Applicant must advance the costs exceeding the Extension Allowance prior to the start of construction. (N)(D)

The Applicant must pay a Contract Minimum Billing for as long as service is taken.

If service is terminated within the first ten (10) years, the Applicant must pay a termination charge equal to the Extension Allowance less 1/10th of the allowance for each year service was taken.

3. 25,000 kW and Greater

The Company will grant Nonresidential Applicants requiring 25,000 kW or more an Extension Allowance of the metering necessary to measure the Applicant's usage. Applicants who have been provided a written Line Extension Allowance estimate dated prior to September 26, 2023, shall be granted an Extension Allowance equal to the estimated annual revenue which the Applicant is expected to pay the Company in a year of normal operations under cost-based service, provided there are no material changes or updates to the Applicant's service request, and the Applicant enters into a written Line Extension agreement with the Company no later than six months following the date of the written estimate. (M)

Apart from the Extension Allowance, the Customer is subject to the same Extension provisions as a Customer with a load less than 25,000 kW.

4. Nonresidential Transportation Electrification Charging

The Company will grant Nonresidential Applicants, for which 80% or greater of the estimated annual load of Applicant's facilities' will be dedicated to serving transportation charging infrastructure, two times the estimated annual revenue which the Applicant is expected to pay the Company in a year of normal operations under cost-based service. The Applicant must advance the costs exceeding the Extension Allowance.

The Applicant must pay a Contract Minimum Billing for as long as service is taken.

If service is terminated within the first ten (10) years, the Applicant must pay a termination charge equal to the Extension Allowance less 1/10th of the allowance for each year service was taken.

(M) to pg. 8

(continued)

III. Nonresidential Extensions (continued)

B. Extension Allowance – Delivery at Secondary or Primary Voltage (continued) (M) from pg. 7

5. Additional Capacity

The Extension Allowance for Consumers, where it is necessary for the Company to increase the capacity of their facilities to serve the Consumer's additional load, is calculated on the increase in revenue estimated to occur as a result of the additional load. The Extension Allowance for Additional Capacity is subject to the same provisions of new line extensions, according to Customer service voltage, total load size, and permanency.

C. Additional Applicants, Advances and Refunds – All Voltages

1. Initial Consumer - 1,000 kW or less

A Consumer that pays for a portion of the construction of an Extension may receive refunds if additional Applicants connect to the Extension. The Consumer is eligible for refunds during the first five (5) years following construction of an Extension for up to three (3) additional Applicants. Each of the next three Applicants, for which refunds are not waived, utilizing any portion of the initial Extension must pay the Company, prior to connection, 25% of the cost of the shared facilities. The Company will refund such payments to the initial Consumer.

2. Initial Consumer – Over 1,000 kW and less than 25,000 kW

A Consumer that pays for a portion of the construction of an Extension may receive refunds if additional Applicants connect to the Extension. The Consumer is eligible for refunds during the first five (5) years following construction of an Extension for up to three (3) additional Applicants. Each of the next three Applicants, for which refunds are not waived, utilizing any portion of the initial Extension must pay the Company, prior to connection, a proportionate share of the cost of the shared facilities. The Company will refund such payments to the initial Consumer. (M)

Proportionate Share = (A + B) x C

Where:
A = [Shared footage of line] x [Average cost per foot of the line]
B = Cost of the other shared distribution equipment, if applicable
C = [New additional connected load]/[Total connected load]

3. Initial Consumer - 25,000 kW or greater (N)

A Consumer that pays for a portion of the construction of an Extension may receive refunds if additional Applicants connect to the Extension. The Consumer is eligible for refunds during the first ten (10) years following construction of an Extension for up to three (3) additional Applicants. Apart from the time following construction that Consumers requiring 25,000 kW or greater are eligible for refunds, Consumers requiring 25,000 kW or more are subject to the provisions of Section III.C.2. (N)

4. Adjustment of Contract Minimum Billing (T)

The Facilities Charges of Consumers that receive a refund are reduced by the Facilities Charge amount associated with the refund and are allocated to the Applicant paying the refund.

(M) to pgs. 9&10

(continued)

III. Nonresidential Extensions (continued)

C. Additional Applicants, Advances and Refunds – All Voltages (continued)

4. Adjustment of Contract Minimum Billing (continued)

Consumers that are no longer eligible for refunds, with ongoing Facilities Charges on Direct Assigned facilities, which subsequently are used to serve other consumers, may have their Facilities Charges adjusted based on their proportionate share of the extension costs. The Consumer's proportionate share is determined using the greater of their total contracted demand or two year historical peak demand for the "New additional connected load" in the proportional share formula above. (M) from pg. 8 (C)

If the Company releases reserved capacity under Section III.D. Consumers may have the basis of their Facilities Charges reduced by the value of the released capacity.

D. Contract Capacity or Demand (N)

Unless the Consumer has paid a Capacity Reservation Charge as outlined in Section I.A of this Rule, the Company is not obligated to reserve capacity in Company substations, or on Company lines, or maintain service facility capacity in place to serve a Consumer in excess of the maximum recorded and billed Consumer demand in the most recent 12 months, unless contract provisions providing for greater demand are less than 12 months old. For Consumers with an executed Line Extension Agreement prior to January 1, 2025, the Company is not obligated to reserve capacity in Company substations, or on Company lines, or maintain service facility capacity in place to serve a Consumer in excess of the maximum recorded and billed Consumer demand in the most recent 36 months, unless contract provisions providing for greater demand are less than 36 months old or unless the Consumer has paid a Capacity Reservation Charge. (N) (C) (C)(N) (N)

If there are contract provisions providing for additional incremental capacity in the future, the cost of which was included in the Consumer's allowance or advance, the incremental capacity will be reserved or made available by the date given in the contract and kept available for a period of 12 months, after which the Company is no longer obligated to keep available the unused portion of that incremental capacity. The incremental capacity will be reserved or made available by the date given in the contract and kept available for a period of 36 months for Consumers with an executed Line Extension Agreement prior to January 1, 2025. (C) (N) (M)

Prior to reducing Reserved Capacity for Consumers requiring greater than 1,000 kW but less than 25,000 kW, the Company shall present Consumers with the alternative of reducing the Reserved Capacity or paying a Capacity Reservation Charge for Excess Reserved Capacity.

If a Consumer's total Reserved Capacity is 25,000 kW or greater, the Consumer shall be subject to a Capacity Reservation Charge and an Excess Demand Charge. Consumer load served under Schedule 848 shall not be subject to the Capacity Reservation or Excess Demand Charge.

Consumers requiring more than 25,000 kW may request to reduce their Reserved Capacity. The Company may reduce a Consumer's Reserved Capacity by up to 10% of the Consumer's total load per year or 50 MW per year, whichever is smaller, or by a larger amount if mutually agreed upon by the Consumer and the Company. (N)

(continued)

(M) to pg. 10

III. Nonresidential Extensions (continued)

D. Contract Capacity or Demand (continued)

The Company may deny load requests depending on available system capacity. The Company is under no obligation to consider load requests more than five years in the future. Consumer requests to increase Reserved Capacity after energization may be considered at the discretion of the Company. (N)

E. Underground Extensions (M) from pg. 8&9

The Company will construct line Extensions underground when requested by the Applicant or if required by local ordinance or conditions. The Applicant must pay for the conversion of any existing overhead facilities to underground, under the terms of Section VI of this Rule. The Applicant must provide all trenching and backfilling, imported backfill material, conduits, and equipment foundations that the Company requires for the Extension. If the Applicant requests, the Company will provide these items at the Applicant's expense. When the Extension is to property which is not part of an improved development, the Company may require the Applicant to pay for facilities on Applicant's property to provide for additional service reliability or for future development.

F. Street Lighting

The Extension Allowance to streetlights taking service under Rate Schedules 51/751 or 53/753 or 54/754 is equal to five times the annual revenue from the lights to be added. The Applicant must provide a non-refundable advance for costs exceeding the Extension Allowance prior to the lights being added. Facilities charges and Contract Minimum Billings do not apply to streetlights. (M)

IV. Extensions to Planned Developments (M) from pg.9

A. General

Planned developments, including subdivisions and mobile home parks, are areas where groups of buildings or dwellings may be constructed at or about the same time. The Company will install facilities in developments before there are actual Applicants for service under the terms of a written contract.

When an existing development is re-platted or changes configuration or use, the revised portion of the development shall be designed to meet current standards. For impacted lots that have had been built upon and have Consumers who have been receiving service in excess of five years, the Applicant will be responsible for the costs of removal, and thereafter their request will be treated as a new construction request. Otherwise the request will be treated as a relocation.

B. Allowances and Advances

For nonresidential developments the Developer must pay a non-refundable advance equal to the Company's estimated installed costs to make primary service available to each lot. An Applicant, who contracts for service before or in conjunction with the Developer, may contract to use the excess of their allowance, if any, to help fund the primary voltage facilities necessary to serve them.

For residential developments the Company will provide the Developer an Extension Allowance of $600 for each lot to which secondary voltage service is made available. The Developer must pay an advance for all other costs.

For multi-unit residential buildings, the Company will provide a total Extension Allowance of $1100 for each residence.

For both nonresidential and residential developments the Company may require the Developer to pay for facilities to provide additional service reliability or future development. (M)

(continued)

(M) to pgs. 11&12

IV. Extensions to Planned Developments (continued)

C. Refunds (M) from pg. 9

The Company will make no refunds due to Applicants connecting within a development. Except for Network Upgrades, a Developer may receive refunds when Applicants outside the development connect to the Extension to the development, or to a feeder extending alongside or through the development, for which the Developer has paid an advance. The Developer is eligible for these refunds during the first five (5) years following construction of the Extension for up to three (3) additional Applicants. Each of the next three (3) Applicants, for which refunds are not waived, connecting to any portion of the refundable Extension, must pay the Company, prior to connection, 25% of the cost of the shared facilities. The Company will refund such payments to the Developer.

D. Underground Extensions

The Company will construct line Extensions underground when requested by the Developer or required by local ordinances or conditions. The Developer must pay for the conversion of any existing overhead facilities to underground, under the terms of Section VI of this Rule. The Developer must provide all trenching and backfilling, imported backfill material, conduits, and equipment foundations that the Company requires for the development. If the Developer requests, the Company will provide these items at the Developer's expense. (M) from pg.10 (M)

V. Extension Exceptions (M) from pg. 10

A. Applicant Built Line Extensions

1. General

An Applicant may contract with someone other than the Company to build a Line Extension. The following circumstances, however, are not an option for Applicant Built Line Extensions: relocations, conversions from overhead to underground, going from single-phase to three-phase, or increasing the capacity of facilities. The Applicant must contract with the Company before starting construction of an Applicant Built Line Extension. When the Applicant has completed construction of the Line Extension and the Company approves it, the Company will connect it to the Company's facilities and assume ownership.

2. Liability and Insurance

The Applicant assumes all risks for the construction of an Applicant Built Line Extension. Before starting construction, the Applicant must furnish a certificate naming the Company as an additional insured for a minimum of $1,000,000. The Applicant may cancel the policy after the Company accepts ownership of the Line Extension.

3. Advance for Design, Specifications, Material Standards and Inspections

The Applicant must advance the Company's estimated costs for design, specifications, material standards and inspections. When the Applicant has completed construction, the Company will determine its actual costs and may adjust that portion of the Applicant's advance. If the actual costs exceed the Applicant's advance, the Applicant must pay the difference before the Company will accept and energize the Line Extension. If the actual costs are less than the Applicant's advance, the Company will refund the difference.

The Company will estimate the frequency of inspections and convey this to the Applicant prior to the signing of the contract. For underground Line Extensions, the Company may require that an inspector be present whenever installation work is done. (M)

(continued) (M) to pgs.12& 13

V. Extension Exceptions (continued) (M) from pg. 10

A. Applicant Built Line Extensions (continued)

4. Construction Standards
The Applicant must construct the Line Extension in accordance with the Company's design, specifications, and material standards and along the Company's selected route. Otherwise, the Company will not accept or energize the Line Extension.

5. Transfer of Ownership
Upon approval of the construction, the Company will assume ownership of the Line Extension. The Applicant must provide the Company unencumbered title to the Line Extension.

6. Rights-of-Way
The Applicant must provide to the Company all required rights-of-way, easements and permits in accordance with paragraph 1. I. of this Rule.

7. Contract Minimum Billing
The Company may require the Applicant to pay a Contract Minimum Billing as defined in paragraph 1. B. of this Rule. (M)

8. Deficiencies in Construction (M) from pg. 11
If, within 24 months of the time the Company energized the Line Extension, it determines that the Applicant provided deficient material or workmanship, the Applicant must pay the cost to correct the deficiency.

9. Line Extension Value
The Company will calculate the value of a Line Extension using its standard estimating methods. The Company will use the Line Extension Value to calculate Contract Minimum Billings, reimbursements, and refunds.

10. Line Extension Allowance
After assuming ownership, the Company will calculate the appropriate Extension Allowance. The Company will then reimburse the Applicant for the construction costs covered by the Extension Allowance, less the cost of any Company provided equipment or services, but in no case more than the Line Extension Value.

B. Duplicate Service Facilities
The Company will furnish Duplicate Service Facilities if the Consumer advances the estimated costs for facilities in excess of those which the Company would otherwise provide. The Consumer also must pay Facilities Charges for the Duplicate Facilities for as long as service is taken, but in no case less than five years.

C. Emergency Service
The Company will grant Applicants requesting Emergency Service an Extension Allowance equal to the estimated increase in annual revenue the Applicant will pay the Company. The Applicant must advance the costs exceeding the Extension Allowance prior to the start of construction. The Applicant must also pay a Contract Minimum Billing for as long as service is taken, but in no case less than five years. (M)

(M) to pgs. 13 & 14

(continued)

D. Intermittent Service Facilities
The Company will serve Intermittent loads provided the Consumer advances the estimated cost of facilities above the cost of facilities which the Company would otherwise install. The Consumer also must pay a Contract Minimum Billing for as long as service is taken, but in no case less than five years. If load fluctuations become a detriment to other Consumers, the Company may modify the facilities and adjust the Contract Minimum Billing. (M) from Pg.11

E. Temporary Service
For Temporary Service requests requiring only a service loop connection and where there are 120/240 volt facilities of adequate capacity available, the Applicant shall pay the Temporary Service charge specified in Schedule 300.

For all other Temporary Service requests the Applicant shall pay:
a) the estimated installation cost, plus
b) the estimated removal cost, plus
c) the estimated cost for rearranging any existing facilities, less
d) the estimated salvage value of the facilities required to provide Temporary Service.

The Applicant is also responsible for electric service supplied under the appropriate rate schedule; any advances required for sharing previous Extensions; and, depending on the customer class, Contract Minimum Billings. (M)

(M) from pg. 12

If a temporary Consumer takes service continuously for 60 consecutive months from the date the Company first delivered service, the Company will classify them as permanent and refund any payment the Consumer made over that required of a permanent Consumer. The Company will not refund the Facilities Charges.

In response to the 2020 wildfires, the Company may waive the costs of Temporary Service to facilitate service restoration at an affected property and to make Temporary Service available for displaced residential customers at a temporary location. Provided, however, the Applicant requests service no later than December 31, 2023. The Applicant remains responsible for electric service supplied under the appropriate rate schedule and any advances required for sharing previous Extensions.

VI. Relocation or Replacement of Facilities

A. Relocation of Facilities
If requested by an Applicant or Consumer, and adequate clearances can be maintained and adequate easements/rights-of-way can be obtained, the Company will: relocate distribution facilities; and/or, replace existing overhead distribution facilities with comparable underground (overhead to underground conversion, or conversion). If existing easements are insufficient for the new facilities, the Applicant is responsible for obtaining new easements. Substation facilities and transmission voltage facilities will be relocated at the discretion of the Company.

For conversions, the new underground system must not impair the use of the remaining overhead system. The Applicant or Consumer must elect either: to provide all trenching and back filling, imported backfill material, conduits, and equipment foundations that the Company requires for the Extension; or, to pay the Company to provide these items. (M)

(M) to pgs. 14&15

(continued)

VI. Relocation or Replacement of Facilities (continued) (M) from pg. 12

A. Relocation of Facilities (continued)

In addition, for both relocations and conversions, the Applicant must advance the following:

1. The estimated installed cost of the new facilities plus the estimated removal expense of the existing facilities, less
2. The estimated salvage value of the removed facilities.

This Advance is not refundable. The Company is not responsible for allocating costs and responsibilities among multiple Applicants.

B. Local Governments – Relocations

When Company facilities located in the franchise easement require relocating due to a public project, the relocation is done without charge to the local government Applicant.

C. Local Governments – Conversions

The conversion costs to a local government Applicant, as part of a public project which would necessitate the relocation of Company's facilities, consist of: the costs of all necessary excavating, road crossings, trenching, backfilling, raceways, ducts, vaults, transformer pads, and other devices peculiar to underground service. If the conversion is not part of a public project necessitating relocation of Company's facilities the overhead retirement costs are included in the conversion costs charged to the local government. The overhead retirement costs are: the original cost, less depreciation, less salvage value, plus removal costs of the existing overhead distribution facilities no longer used or useful by reason of the conversion. (M)

In addition the local government shall by ordinance or other means provide that all Consumers, served from the overhead facilities to be removed, perform wiring changes on their Premises so the service may be furnished from the underground distribution system in accordance with the Company's rules, and have authorized the Company to discontinue its overhead service upon completion of the underground conversion. (M) from pg. 13

The Company will not charge the local government if the total conversion costs incurred by the Company during one calendar year for conversions does not exceed five-one hundredths of one percent (0.05%) of the Company's annual revenues derived from Consumers residing within the boundaries of the local government. Otherwise the local government shall, in advance, either pay the conversion costs or direct the Company to expense the conversion costs. When expensed said conversion shall be conditioned by the following:

1. Company shall collect the conversion costs from the Consumers located within the boundaries of the local government; however, the local government may direct Company to collect conversion costs from only a portion of the Consumers located within the boundaries of the local government.
2. Conversion costs incurred by the Company shall be accumulated in a separate account in Company's books with interest accruing from the date Company incurs the cost. The rate of such interest shall be equal to the effective cost of the senior security issue which most recently preceded the incurrence of the cost. (M)

(M) to pg. 15

(continued)

VI. Relocation or Replacement of Facilities (continued) (M) from pg. 13

C. Local Governments – Conversions (continued)

3. Company shall collect the conversion costs and interest over a reasonable period of time subject to approval of The Public Utility Commission of Oregon. Said pay-back shall not exceed the depreciable life of the facilities. Collection shall begin as soon as practicable after the end of the year in which the conversion costs are incurred.

4. Conversion costs to be recovered from each Consumer shall be calculated by applying a uniform percentage to each Consumer's total monthly bill for service rendered within the boundaries of the local government. Said conversion costs will be shown as a separate item on individual Consumer bills.

VII. Contract Administration Credit

Applicants may waive their right to receive refunds on a Line Extension advance. Applicants who waive this right will receive a Contract Administration Credit up to the amount specified in Schedule 300. The Applicant's choice to receive the Contract Administration Credit must be made at the time the Extension advance is paid.

(M)

Docket No. UE 433
Exhibit PAC/1902
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

February 2024

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
Functionalized Revenue Requirement
12 Months Ended December 31, 2025 Forecast

Function		Revenue Requirement	
Production		$	964,517,931
Transmission		$	318,359,981
Distribution		$	463,303,098
Distribution-Lighting		$	3,688,207
Distribution Total		$	466,991,304
Ancillary		$	24,138,546
Customer Billing		$	16,740,247
Customer Metering		$	19,538,124
Customer Other		$	10,050,398
Retail Service	a	$	-
Public Purposes	b	$	-
Total State of Oregon		$	1,820,336,533

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, 2025 Forecast

										Customer			Distribution Components		
		ROR	ROE	Total $	Production	Transmission	Distribution	Distribution-Lighting	Ancillary	Billing	Metering	Other	Poles & Wires	Poles & Wires-Lighting	Franchise Fees
1	Functionalized Situs Revenues @ Earned	5.83%	6.47%	1,680,937,338	936,889,523	259,746,775	414,128,392	3,204,398	24,138,546	15,969,012	17,101,232	9,759,459	368,770,878	2,853,436	45,708,476
2	System Allocated Revenues			-	-	-	-	-	-	-	-	-	-	-	-
3	Total Oregon General Business Revenue			1,680,937,338	936,889,523	259,746,775	414,128,392	3,204,398	24,138,546	15,969,012	17,101,232	9,759,459	368,770,878	2,853,436	45,708,476
4															
5	Target Increase in Return	7.74%	10.30%	101,502,284	20,591,618	43,684,772	34,280,745	337,273	-	574,807	1,816,230	216,838	34,280,745	337,273	-
6															
7	Add														
8	Uncollectible Expense			872,291	172,885	366,772	307,711	3,027	-	4,826	15,249	1,821	287,817	2,832	20,089
9	Franchise Tax			3,172,871			3,141,958	30,912							3,172,871
10	Other Revenue Based Taxes			759,539	150,538	319,364	267,936	2,636	-	4,202	13,278	1,585	250,614	2,466	17,493
11	Inc Taxes - State			6,110,590	1,239,646	2,629,889	2,063,752	20,304	-	34,604	109,340	13,054	2,063,752	20,304	-
12	Inc Taxes - Federal			26,981,620	5,473,721	11,612,408	9,112,603	89,655	-	152,797	482,795	57,641	9,112,603	89,655	-
13	Total Increase Needed			139,399,195	27,628,408	58,613,205	49,174,706	483,808	-	771,236	2,436,892	290,939	45,995,532	452,530	3,210,453
14															
15	Total Oregon General Business Revenue @	7.74%	10.30%	1,820,336,533	964,517,931	318,359,981	463,303,098	3,688,207	24,138,546	16,740,247	19,538,124	10,050,398	414,766,409	3,305,966	48,918,929
16	Less: System Allocated Revenues			-	-	-	-	-	-	-	-	-	-	-	-
17	Total Unbundled Revenue Requirement			1,820,336,533	964,517,931	318,359,981	463,303,098	3,688,207	24,138,546	16,740,247	19,538,124	10,050,398	414,766,409	3,305,966	48,918,929
18															
19	Rate Base			5,300,883,073	1,075,382,287	2,281,405,531	1,790,287,004	17,613,846	-	30,018,856	94,851,316	11,324,232	1,790,287,004	17,613,846	-
					20.29%	43.04%	33.77%	0.33%	0.00%	0.57%	1.79%	0.21%	33.77%	0.33%	0.00%

Notes:

Row 9: Franchise Tax @	2.28%
Row 11: Inc Taxes - State	4.54%
Row 12: Inc Taxes - Federal	21.00%

Docket No. UE 433
Exhibit PAC/1903
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

February 2024

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
Unbundled Results of Operations
12 Months Ended December 31, 2025 Forecast

		Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Other
Operating Revenues										
	General Business Revenues	1,680,937,338	936,889,523	259,746,775	414,128,392	3,204,398	24,138,546	15,969,012	17,101,232	9,759,459
	Special Sales	92,078,056	92,078,056	-	-	-	-	-	-	-
	Other Operating Revenues	71,932,639	31,746,318	51,621,152	5,575,952	2,916	(24,138,546)	6,262,511	367,691	494,645
	Total Operating Revenues	1,844,948,033	1,060,713,897	311,367,927	419,704,344	3,207,315	-	22,231,523	17,468,923	10,254,105
Operating Expenses										
	Steam Production	236,350,339	236,350,339	-	-	-	-	-	-	-
	Nuclear Production	-	-	-	-	-	-	-	-	-
	Hydro Production	13,610,836	13,610,836	-	-	-	-	-	-	-
	Other Power Supply	602,291,370	602,291,370	-	-	-	-	-	-	-
	ECD	-	-	-	-	-	-	-	-	-
	Transmission	64,748,998	248,277	64,500,721	-	-	-	-	-	-
	Distribution	114,708,178	-	-	111,916,347	941,500	-	-	1,850,332	-
	Customer Accounts	31,422,542	5,881,550	1,726,503	2,327,218	17,784	-	14,299,271	3,535,910	3,634,305
	Customer Service	5,308,096	-	-	2,480,719	-	-	-	-	2,827,377
	Sales	-	-	-	-	-	-	-	-	-
	Administrative & General	61,612,724	12,135,653	5,818,005	40,343,603	69,006	-	1,581,282	1,119,438	545,737
	Total O & M Expenses	1,130,053,083	870,518,025	72,045,230	157,067,885	1,028,290	-	15,880,553	6,505,679	7,007,420
	Depreciation	317,077,683	191,324,243	57,044,901	64,948,371	786,058	-	659,438	2,050,031	264,640
	Amortization Expense	30,904,843	8,098,820	1,955,540	14,195,898	41,772	-	3,071,679	1,647,359	1,893,774
	Taxes Other Than Income	100,572,803	23,204,851	15,179,081	60,788,950	163,121	-	329,022	726,809	180,970
	Income Taxes - Federal	(42,794,680)	(79,450,171)	13,441,594	21,616,624	446,871	-	50,079	1,266,174	(165,852)
	Income Taxes - State	5,307,130	3,051,222	895,673	1,207,311	9,226	-	63,951	50,251	29,497
	Income Taxes - Def Net	(4,937,211)	(18,584,960)	17,915,865	(4,483,316)	(294,090)	-	428,100	(302,791)	383,980
	Investment Tax Credit Adj.	-	-	-	-	-	-	-	-	-
	Misc Revenue & Expense	(30,006)	(92,792)	(9,553)	72,340	-	-	-	-	-
	Total Operating Expenses	1,536,153,644	998,069,238	178,468,330	315,414,063	2,181,248	-	20,482,823	11,943,512	9,594,430
Operating Revenue for Return		308,794,389	62,644,660	132,899,597	104,290,280	1,026,066	-	1,748,700	5,525,410	659,675
Rate Base										
	Electric Plant in Service	10,425,808,241	4,108,230,762	3,060,325,174	2,986,873,710	32,954,998	-	58,820,231	145,292,638	33,310,728
	Plant Held for Future Use	-	(79,561)	264,553	(175,384)	-	-	(4,456)	(5,152)	-
	Misc Deferred Debits	101,941,905	85,321,466	4,711,048	9,211,018	69,744	-	1,586,185	464,089	578,354
	Elec Plant Acq Adj	703,248	703,248	-	-	-	-	-	-	-
	Nuclear Fuel	-	-	-	-	-	-	-	-	-
	Prepayments	16,838,184	7,370,468	1,826,768	5,913,341	44,788	-	1,015,019	297,642	370,158
	Fuel Stock	37,268,548	37,268,548	-	-	-	-	-	-	-
	Material & Supplies	129,822,071	95,215,135	1,936,867	31,763,560	-	-	-	906,510	-
	Working Capital	47,868,648	26,780,000	4,277,696	13,865,898	99,664	-	1,628,199	590,300	626,890
	Weatherization Loans	-	-	-	-	-	-	-	-	-
	Miscellaneous Rate Base	-	-	-	-	-	-	-	-	-
	Total Electric Plant	10,760,250,845	4,360,810,065	3,073,342,106	3,047,452,144	33,169,195	-	63,045,178	147,546,028	34,886,130
Rate Base Deductions										
	Accum Prov For Depr	(4,043,129,802)	(2,063,552,941)	(670,080,406)	(1,249,778,572)	(15,913,180)	-	(3,620,682)	(38,676,835)	(1,507,185)
	Accum Prov For Amort	(232,858,605)	(77,447,946)	(53,654,275)	(37,908,980)	(57,315)	-	(28,192,106)	(15,047,019)	(20,550,964)
	Accum Def Income Taxes	(703,568,427)	(715,212,123)	(26,272,350)	38,191,845	492,213	-	(793,199)	1,375,676	(1,350,487)
	Unamortized ITC	(40,918)	(17,136)	(2,957)	(16,110)	(122)	-	(2,772)	(811)	(1,011)
	Customer Adv for Const	(46,658,522)	-	(41,481,126)	(4,912,218)	(55,062)	-	-	(210,115)	-
	Customer Service Deposits	-	-	-	-	-	-	-	-	-
	Misc. Rate Base Deductions	(433,111,498)	(429,197,632)	(445,461)	(2,741,104)	(21,881)	-	(417,563)	(135,607)	(152,252)
	Total Rate Base Deductions	(5,459,367,773)	(3,285,427,778)	(791,936,575)	(1,257,165,140)	(15,555,348)	-	(33,026,322)	(52,694,712)	(23,561,898)
Total Rate Base		5,300,883,073	1,075,382,287	2,281,405,531	1,790,287,004	17,613,846	-	30,018,856	94,851,316	11,324,232
Return on Rate Base		5.8253%	5.8253%	5.8253%	5.8253%	5.8253%	5.8253%	5.8253%	5.8253%	5.8253%
Return on Equity		6.4704%	6.4704%	6.4704%	6.4704%	6.4704%	6.4704%	6.4704%	6.4704%	6.4704%

2020 PROTOCOL
RESULTS OF OPERATIONS SUMMARY
12 Months Ended December 31, 2025 Forecast

		Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
Operating Revenues											
	General Business Revenues	1,680,937,338	936,889,523	259,746,775	414,128,392	3,204,398	24,138,546	15,969,012	17,101,232	9,759,459	-
	General Business Revenues	-	-	-	-	-	-	-	-	-	-
	Interdepartmental	-	-	-	-	-	-	-	-	-	-
	Special Sales	92,078,056	92,078,056	-	-	-	-	-	-	-	-
	Other Operating Revenues	71,932,639	31,746,318	51,621,152	5,575,952	2,916	(24,138,546)	6,262,511	367,691	494,645	-
	Total Operating Revenues	1,844,948,033	1,060,713,897	311,367,927	419,704,344	3,207,315	-	22,231,523	17,468,923	10,254,105	-
Operating Expenses											
	Steam Production	236,350,339	236,350,339	-	-	-	-	-	-	-	-
Operating Expenses	Nuclear Production	-	-	-	-	-	-	-	-	-	-
	Hydro Production	13,610,836	13,610,836	-	-	-	-	-	-	-	-
	Other Power Supply	602,291,370	602,291,370	-	-	-	-	-	-	-	-
	ECD	-	-	-	-	-	-	-	-	-	-
	Transmission	64,748,998	248,277	64,500,721	-	-	-	-	-	-	-
	Distribution	114,708,178	-	-	111,916,347	941,500	-	-	1,850,332	-	-
	Customer Accounts	31,422,542	5,881,550	1,726,503	2,327,218	17,784	-	14,299,271	3,535,910	3,634,305	-
	Customer Service	5,308,096	-	-	2,480,719	-	-	-	-	2,827,377	-
	Sales	-	-	-	-	-	-	-	-	-	-
	Administrative & General	61,612,724	12,135,653	5,818,005	40,343,603	69,006	-	1,581,282	1,119,438	545,737	-
	Total O & M Expenses	1,130,053,083	870,518,025	72,045,230	157,067,885	1,028,290	-	15,880,553	6,505,679	7,007,420	-
	Depreciation	317,077,683	191,324,243	57,044,901	64,948,371	786,058	-	659,438	2,050,031	264,640	-
	Amortization Expense	30,904,843	8,098,820	1,955,540	14,195,898	41,772	-	3,071,679	1,647,359	1,893,774	-
	Taxes Other Than Income	100,572,803	23,204,851	15,179,081	60,788,950	163,121	-	329,022	726,809	180,970	-
	Income Taxes - Federal	(42,794,680)	(79,450,171)	13,441,594	21,616,624	446,871	-	50,079	1,266,174	(165,852)	-
	Income Taxes - State	5,307,130	3,051,222	895,673	1,207,311	9,226	-	63,951	50,251	29,497	-
	Income Taxes - Def Net	(4,937,211)	(18,584,960)	17,915,865	(4,483,316)	(294,090)	-	428,100	(302,791)	383,980	-
	Investment Tax Credit Adj.	-	-	-	-	-	-	-	-	-	-
	Misc Revenue & Expense	(30,006)	(92,792)	(9,553)	72,340	-	-	-	-	-	-
	Total Operating Expenses	1,536,153,644	998,069,238	178,468,330	315,414,063	2,181,248	-	20,482,823	11,943,512	9,594,430	-
Operating Revenue for Return		308,794,389	62,644,660	132,899,597	104,290,280	1,026,066	-	1,748,700	5,525,410	659,675	-
Rate Base											
	Electric Plant in Service	10,425,808,241	4,108,230,762	3,060,325,174	2,986,873,710	32,954,998	-	58,820,231	145,292,638	33,310,728	-
Rate Base	Plant Held for Future Use	-	(79,561)	264,553	(175,384)	-	-	(4,456)	(5,152)	-	-
	Misc Deferred Debits	101,941,905	85,321,466	4,711,048	9,211,018	69,744	-	1,586,185	464,089	578,354	-
	Elec Plant Acq Adj	703,248	703,248	-	-	-	-	-	-	-	-
	Nuclear Fuel	-	-	-	-	-	-	-	-	-	-
	Prepayments	16,838,184	7,370,468	1,826,768	5,913,341	44,788	-	1,015,019	297,642	370,158	-
	Fuel Stock	37,268,548	37,268,548	-	-	-	-	-	-	-	-
	Material & Supplies	129,822,071	95,215,135	1,936,867	31,763,560	-	-	-	906,510	-	-
	Working Capital	47,868,648	26,780,000	4,277,696	13,865,898	99,664	-	1,628,199	590,300	626,890	-
	Weatherization Loans	-	-	-	-	-	-	-	-	-	-
	Miscellaneous Rate Base	-	-	-	-	-	-	-	-	-	-
	Total Electric Plant	10,760,250,845	4,360,810,065	3,073,342,106	3,047,452,144	33,169,195	-	63,045,178	147,546,028	34,886,130	-

Rate Base Deductions											
	Accum Prov For Depr	(4,043,129,802)	(2,063,552,941)	(670,080,406)	(1,249,778,572)	(15,913,180)	-	(3,620,682)	(38,676,835)	(1,507,185)	-
Rate Base Deduction	Accum Prov For Amort	(232,858,605)	(77,447,946)	(53,654,275)	(37,908,980)	(57,315)	-	(28,192,106)	(15,047,019)	(20,550,964)	-
	Accum Def Income Taxes	(703,568,427)	(715,212,123)	(26,272,350)	38,191,845	492,213	-	(793,199)	1,375,676	(1,350,487)	-
	Unamortized ITC	(40,918)	(17,136)	(2,957)	(16,110)	(122)	-	(2,772)	(811)	(1,011)	-
	Customer Adv for Const	(46,658,522)	-	(41,481,126)	(4,912,218)	(55,062)	-	-	(210,115)	-	-
	Customer Service Deposits	-	-	-	-	-	-	-	-	-	-
	Misc. Rate Base Deductions	(433,111,498)	(429,197,632)	(445,461)	(2,741,104)	(21,881)	-	(417,563)	(135,607)	(152,252)	-
	Total Rate Base Deductions	(5,459,367,773)	(3,285,427,778)	(791,936,575)	(1,257,165,140)	(15,555,348)	-	(33,026,322)	(52,694,712)	(23,561,898)	-
Total Rate Base		5,300,883,073	1,075,382,287	2,281,405,531	1,790,287,004	17,613,846	-	30,018,856	94,851,316	11,324,232	-
Return on Rate Base		5.8253%	5.8253%	5.8253%	5.8253%	5.8253%	5.8253%	5.8253%	5.8253%	5.8253%	0.0000%
Return on Equity		6.4704%	6.4704%	6.4704%	6.4704%	6.4704%	6.4704%	6.4704%	6.4704%	6.4704%	0.0000%

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	804,392,320	936,889,523	259,746,775	414,128,392	3,204,398	24,138,546	15,969,012	17,101,232	9,759,459	-
	Less Klamath Surcharge Revenue												
		P	S	-	-	-	-	-	-	-	-	-	-
				804,392,320	936,889,523	259,746,775	414,128,392	3,204,398	24,138,546	15,969,012	17,101,232	9,759,459	-
442	Commercial & Industrial Sales												
			S	872,999,594									
		P	SE	-	-	-	-	-	-	-	-	-	-
		PT	SG	-	-	-	-	-	-	-	-	-	-
				872,999,594	-	-	-	-	-	-	-	-	-
444	Public Street & Highway Lighting												
			S	3,545,424									
			SO	-									
				3,545,424	-	-	-	-	-	-	-	-	-
445	Other Sales to Public Authority												
			S	-									
				-	-	-	-	-	-	-	-	-	-
448	Interdepartmental												
		D_SPLIT	S	-	-	-	-	-	-	-	-	-	-
		GP	SO	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
Total Sales to Ultimate Customers				**1,680,937,338**	**936,889,523**	**259,746,775**	**414,128,392**	**3,204,398**	**24,138,546**	**15,969,012**	**17,101,232**	**9,759,459**	**-**
447	Sales for Resale-Non NPC												
		P	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
447NPC	Sales for Resale-NPC												
		P	SG	92,078,056	92,078,056	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				92,078,056	92,078,056	-	-	-	-	-	-	-	-
	Total Sales for Resale			92,078,056	92,078,056	-	-	-	-	-	-	-	-
449	Provision for Rate Refund												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
				-	-	-	-	-	-	-	-	-	-
Total Sales from Electricity				**1,773,015,394**	**1,028,967,579**	**259,746,775**	**414,128,392**	**3,204,398**	**24,138,546**	**15,969,012**	**17,101,232**	**9,759,459**	**-**
450	Forfeited Discounts & Interest												
		C_BILLING	S	5,583,122	-	-	-	-	-	5,583,122	-	-	-
		C_BILLING	SO	-	-	-	-	-	-	-	-	-	-
				5,583,122	-	-	-	-	-	5,583,122	-	-	-
451	Misc Electric Revenue												
		CSS_SYS	S	1,520,715	-	-	-	-	-	674,184	354,833	491,698	-
		C_METER	S	-	-	-	-	-	-	-	-	-	-
		GP	SG	-	-	-	-	-	-	-	-	-	-
		DSM	SO	-	-	-	-	-	-	-	-	-	-
				1,520,715	-	-	-	-	-	674,184	354,833	491,698	-
453	Water Sales												
		P	SG	1,339	1,339	-	-	-	-	-	-	-	-
				1,339	1,339	-	-	-	-	-	-	-	-
454	Rent of Electric Property												
		D	S	5,282,389	-	-	5,282,389	-	-	-	-	-	-
		T	SG	993,883	-	993,883	-	-	-	-	-	-	-
		GP	SO	922,589	363,541	270,811	264,311	2,916	-	5,205	12,857	2,948	-
				7,198,861	363,541	1,264,694	5,546,700	2,916	-	5,205	12,857	2,948	-
	Oregon Ancillary Services				24,138,546				(24,138,546)				
456	Other Electric Revenue												
		OTHSGR	S	-	-	-	-	-	-	-	-	-	-
		C_BILLING	CN	-	-	-	-	-	-	-	-	-	-
		OTHSE	SE	9,890,899	-	9,890,899	-	-	-	-	-	-	-
		OTHSO	SO	27,369	-	-	27,369	-	-	-	-	-	-
		OTHSGR	SG	47,710,335	7,242,892	40,465,560	1,883	-	-	-	-	-	-
				57,628,602	7,242,892	50,356,458	29,252	-	-	-	-	-	-
	Total Other Electric Revenues			**71,932,639**	**31,746,318**	**51,621,152**	**5,575,952**	**2,916**	**(24,138,546)**	**6,262,511**	**367,691**	**494,645**	**-**
Total Electric Operating Revenues				**1,844,948,033**	**1,060,713,897**	**311,367,927**	**419,704,344**	**3,207,315**	**-**	**22,231,523**	**17,468,923**	**10,254,105**	**-**
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	-	-	-	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
				-	-	-	-	-	-	-	-	-	-
4118	Gain from Emission Allowances												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SE	(24)	(24)	-	-	-	-	-	-	-	-
				(24)	(24)	-	-	-	-	-	-	-	-
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	80,879	-	-	80,879	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-	-
		B_Center	CN	-	-	-	-	-	-	-	-	-	-
		PTD	SO	(30,170)	(12,078)	(9,553)	(8,539)	-	-	-	-	-	-
		P	SG	(80,690)	(80,690)	-	-	-	-	-	-	-	-
				(29,982)	(92,768)	(9,553)	72,340	-	-	-	-	-	-
Total Miscellaneous Revenues				**(30,006)**	**(92,792)**	**(9,553)**	**72,340**	**-**	**-**	**-**	**-**	**-**	**-**

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
Miscellaneous Expenses													
4311	Interest on Customer Deposits												
		C_BILLING	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
Total Miscellaneous Expenses				**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Net Misc Revenue and Expense				**(30,006)**	**(92,792)**	**(9,553)**	**72,340**	**-**	**-**	**-**	**-**	**-**	**-**
500	Operation Supervision & Engineering												
		P	SG	4,147,697	4,147,697	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	(306)	(306)	-	-	-	-	-	-	-	-
				4,147,391	4,147,391	-	-	-	-	-	-	-	-
501	Fuel Related-Non NPC												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SE	9,949,333	9,949,333	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
				9,949,333	9,949,333	-	-	-	-	-	-	-	-
501NPC	Fuel Related-NPC												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SE	146,184,550	146,184,550	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
				146,184,550	146,184,550	-	-	-	-	-	-	-	-
	Total Fuel Related			156,133,883	156,133,883	-	-	-	-	-	-	-	-
502	Steam Expenses												
		P	SG	22,112,287	22,112,287	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	(645)	(645)	-	-	-	-	-	-	-	-
				22,111,642	22,111,642	-	-	-	-	-	-	-	-
503	Steam From Other Sources-Non-NPC												
		P	SE	198	198	-	-	-	-	-	-	-	-
				198	198	-	-	-	-	-	-	-	-
503NPC	Steam From Other Sources-NPC												
		P	SE	1,426,328	1,426,328	-	-	-	-	-	-	-	-
				1,426,328	1,426,328	-	-	-	-	-	-	-	-
505	Electric Expenses												
		P	SG	202,393	202,393	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				202,393	202,393	-	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
506	Misc. Steam Expense												
		P	SG	10,101,178	10,101,178	-	-	-	-	-	-	-	-
		P	SG	(1,849,156)	(1,849,156)	-	-	-	-	-	-	-	-
		P	SE	1,385,726	1,385,726	-	-	-	-	-	-	-	-
				9,637,748	9,637,748	-	-	-	-	-	-	-	-
507	Rents												
		P	SG	(60,681)	(60,681)	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				(60,681)	(60,681)	-	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
510	Maint Supervision & Engineering												
		P	SG	1,402,228	1,402,228	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	536,941	536,941	-	-	-	-	-	-	-	-
				1,939,169	1,939,169	-	-	-	-	-	-	-	-
511	Maintenance of Structures												
		P	SG	6,206,527	6,206,527	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	(1,062)	(1,062)	-	-	-	-	-	-	-	-
				6,205,465	6,205,465	-	-	-	-	-	-	-	-
512	Maintenance of Boiler Plant												
		P	SG	23,610,223	23,610,223	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	(2,977,960)	(2,977,960)	-	-	-	-	-	-	-	-
				20,632,263	20,632,263	-	-	-	-	-	-	-	-
513	Maintenance of Electric Plant												
		P	SG	10,067,927	10,067,927	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	(22)	(22)	-	-	-	-	-	-	-	-
				10,067,905	10,067,905	-	-	-	-	-	-	-	-
514	Maintenance of Misc. Steam Plant												
		P	SG	3,908,424	3,908,424	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	(1,788)	(1,788)	-	-	-	-	-	-	-	-
				3,906,636	3,906,636	-	-	-	-	-	-	-	-
Total Steam Power Generation				**236,350,339**	**236,350,339**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
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	-	-	-	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
				-	-	-	-	-	-	-	-	-	-
524	Misc. Nuclear Expenses												
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
528	Maintenance Super & Engineering												
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
529	Maintenance of Structures												
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
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	256,728	256,728	-	-	-	-	-	-	-	-
		P	SG	(1,485)	(1,485)	-	-	-	-	-	-	-	-
		P	SG	(573,977)	(573,977)	-	-	-	-	-	-	-	-
		P	SG	2,530,042	2,530,042	-	-	-	-	-	-	-	-
		P	SG	982,825	982,825	-	-	-	-	-	-	-	-
				3,194,133	3,194,133	-	-	-	-	-	-	-	-
536	Water For Power												
		P	DGP	-	-	-	-	-	-	-	-	-	-
		P	SG	(27)	(27)	-	-	-	-	-	-	-	-
		P	SG	127,795	127,795	-	-	-	-	-	-	-	-
				127,768	127,768	-	-	-	-	-	-	-	-
537	Hydraulic Expenses												
		P	SG	(44)	(44)	-	-	-	-	-	-	-	-
		P	SG	1,133,091	1,133,091	-	-	-	-	-	-	-	-
		P	SG	93,456	93,456	-	-	-	-	-	-	-	-
		P	SG	(38)	(38)	-	-	-	-	-	-	-	-
				1,226,465	1,226,465	-	-	-	-	-	-	-	-
538	Electric Expenses												
		P	DGP	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
539	Misc. Hydro Expenses												
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	4,142,258	4,142,258	-	-	-	-	-	-	-	-
		P	SG	2,228,857	2,228,857	-	-	-	-	-	-	-	-
		P	SG	(1,396)	(1,396)	-	-	-	-	-	-	-	-
		P	SG	(1,270)	(1,270)	-	-	-	-	-	-	-	-
				6,368,450	6,368,450	-	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
540	Rents (Hydro Generation)												
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	481,295	481,295	-	-	-	-	-	-	-	-
		P	SG	(36,500)	(36,500)	-	-	-	-	-	-	-	-
				444,795	444,795	-	-	-	-	-	-	-	-
541	Maint Supervision & Engineering												
		P	DGP	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	418	418	-	-	-	-	-	-	-	-
				418	418	-	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
542	Maintenance of Structures												
		P	SG	(13)	(13)	-	-	-	-	-	-	-	-
		P	SG	201,005	201,005	-	-	-	-	-	-	-	-
		P	SG	6,022	6,022	-	-	-	-	-	-	-	-
				207,015	207,015	-	-	-	-	-	-	-	-
543	Maintenance of Dams & Waterways												
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	257,020	257,020	-	-	-	-	-	-	-	-
		P	SG	140,094	140,094	-	-	-	-	-	-	-	-
				397,113	397,113	-	-	-	-	-	-	-	-
544	Maintenance of Electric Plant												
		P	SG	(55)	(55)	-	-	-	-	-	-	-	-
		P	SG	401,687	401,687	-	-	-	-	-	-	-	-
		P	SG	95,952	95,952	-	-	-	-	-	-	-	-
				497,584	497,584	-	-	-	-	-	-	-	-
545	Maintenance of Misc. Hydro Plant												
		P	SG	(213)	(213)	-	-	-	-	-	-	-	-
		P	SG	(35)	(35)	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	898,824	898,824	-	-	-	-	-	-	-	-
		P	SG	248,518	248,518	-	-	-	-	-	-	-	-
				1,147,094	1,147,094	-	-	-	-	-	-	-	-
Total Hydraulic Power Generation				**13,610,836**	**13,610,836**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
546	Operation Super & Engineering												
		P	SG	141,641	141,641	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	(15)	(15)	-	-	-	-	-	-	-	-
				141,627	141,627	-	-	-	-	-	-	-	-
547	Fuel-Non-NPC												
		P	SE	-	-	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
547NPC	Fuel-NPC												
		P	SE	159,493,589	159,493,589	-	-	-	-	-	-	-	-
		P	SE	165,441	165,441	-	-	-	-	-	-	-	-
				159,659,030	159,659,030	-	-	-	-	-	-	-	-
548	Generation Expense												
		P	SG	6,399,927	6,399,927	-	-	-	-	-	-	-	-
		P	SG	248,635	248,635	-	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
		P	SG	(272)	(272)	-	-	-	-	-	-	-	-
				6,648,290	6,648,290	-	-	-	-	-	-	-	-
549	Miscellaneous Other												
		P	S	34,441	34,441	-	-	-	-	-	-	-	-
		P	SG	1,168,969	1,168,969	-	-	-	-	-	-	-	-
		P	SG	1,848,652	1,848,652	-	-	-	-	-	-	-	-
		P	SG	1,191,673	1,191,673	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				4,243,736	4,243,736	-	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
550	Maint Supervision & Engineering												
		P	S	390,750	390,750	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	11,190	11,190	-	-	-	-	-	-	-	-
		P	SG	2,985,382	2,985,382	-	-	-	-	-	-	-	-
				3,387,322	3,387,322	-	-	-	-	-	-	-	-
551	Maint Supervision & Engineering												
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
552	Maintenance of Structures												
		P	SG	665,752	665,752	-	-	-	-	-	-	-	-
		P	SG	32,730	32,730	-	-	-	-	-	-	-	-
		P	SG	(188)	(188)	-	-	-	-	-	-	-	-
				698,295	698,295	-	-	-	-	-	-	-	-
553	Maint of Generation & Electric Plant												
		P	SG	926,612	926,612	-	-	-	-	-	-	-	-
		P	SG	5,014,625	5,014,625	-	-	-	-	-	-	-	-
		P	SG	81,188	81,188	-	-	-	-	-	-	-	-
		P	SG	473,473	473,473	-	-	-	-	-	-	-	-
				6,495,898	6,495,898	-	-	-	-	-	-	-	-
554	Maintenance of Misc. Other												
		P	SG	605,871	605,871	-	-	-	-	-	-	-	-
		P	SG	488,080	488,080	-	-	-	-	-	-	-	-
		P	SG	35,869	35,869	-	-	-	-	-	-	-	-
		P	SG	(3)	(3)	-	-	-	-	-	-	-	-
				1,129,817	1,129,817	-	-	-	-	-	-	-	-
Total Other Power Generation				**182,404,015**	**182,404,015**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
555	Purchased Power-Non NPC												
		P	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
555NPC	Purchased Power-NPC												
		P	S	(1,482,488)	(1,482,488)	-	-	-	-	-	-	-	-
		P	SG	393,560,814	393,560,814	-	-	-	-	-	-	-	-
		P	SE	20,221,942	20,221,942	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	DGP	-	-	-	-	-	-	-	-	-	-
				412,300,269	412,300,269	-	-	-	-	-	-	-	-
	Total Purchased Power			412,300,269	412,300,269	-	-	-	-	-	-	-	-
556	System Control & Load Dispatch												
		P	SG	705,028	705,028	-	-	-	-	-	-	-	-
				705,028	705,028	-	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
557	Other Expenses												
		P	S	8,126,293	8,126,293	-	-	-	-	-	-	-	-
		P	SG	9,754,073	9,754,073	-	-	-	-	-	-	-	-
		P	SGCT	-	-	-	-	-	-	-	-	-	-
		P	SE	1,693	1,693	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	TROJP	-	-	-	-	-	-	-	-	-	-
				17,882,058	17,882,058	-	-	-	-	-	-	-	-
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				**419,887,355**	**419,887,355**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
TOTAL PRODUCTION EXPENSE				**852,252,545**	**852,252,545**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Embedded Cost Differentials												
	Company Owne	P	DGP	-	-	-	-	-	-	-	-	-	-
	Company Owne	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	P	S	-	-	-	-	-	-	-	-	-	-
	ECD Hydro	P	S	-	-	-	-	-	-	-	-	-	-
	Mid-C Contract	P	MC	-	-	-	-	-	-	-	-	-	-
	Mid-C Contract	P	SG	-	-	-	-	-	-	-	-	-	-
	Klamath Dam Remo	P	S	-	-	-	-	-	-	-	-	-	-
	Less Klamath Surcharge Expense												
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
560	Operation Supervision & Engineering												
		T	SG	3,094,494	-	3,094,494	-	-	-	-	-	-	-
		T	SG	(2,551)	-	(2,551)	-	-	-	-	-	-	-
				3,091,943	-	3,091,943	-	-	-	-	-	-	-
561	Load Dispatching												
		T	SG	5,235,993	-	5,235,993	-	-	-	-	-	-	-
		T	SG	(591)	-	(591)	-	-	-	-	-	-	-
				5,235,402	-	5,235,402	-	-	-	-	-	-	-
562	Station Expense												
		T	SG	1,305,687	-	1,305,687	-	-	-	-	-	-	-
		T	SG	(5)	-	(5)	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
				1,305,682	-	1,305,682	-	-	-	-	-	-	-
563	Overhead Line Expense												
		T	SG	487,058	-	487,058	-	-	-	-	-	-	-
		T	SG	(207)	-	(207)	-	-	-	-	-	-	-
				486,851	-	486,851	-	-	-	-	-	-	-
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	41,968,377	-	41,968,377	-	-	-	-	-	-	-
		T	SE	3,147,225	-	3,147,225	-	-	-	-	-	-	-
				45,115,602	-	45,115,602	-	-	-	-	-	-	-
	Total Transmission of Electricity by Others			45,115,602	-	45,115,602	-	-	-	-	-	-	-
566	Misc. Transmission Expense												
		T	SG	1,071,510	-	1,071,510	-	-	-	-	-	-	-
		T	SG	(61)	-	(61)	-	-	-	-	-	-	-
				1,071,449	-	1,071,449	-	-	-	-	-	-	-
567	Rents - Transmission												
		T	SG	639,200	-	639,200	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-	-
				639,200	-	639,200	-	-	-	-	-	-	-
568	Maint Supervision & Engineering												
		T	SG	370,210	-	370,210	-	-	-	-	-	-	-
		T	SG	(380)	-	(380)	-	-	-	-	-	-	-
				369,830	-	369,830	-	-	-	-	-	-	-
569	Maintenance of Structures												
		T	SG	1,696,140	-	1,696,140	-	-	-	-	-	-	-
		T	SG	(4)	-	(4)	-	-	-	-	-	-	-
				1,696,136	-	1,696,136	-	-	-	-	-	-	-
570	Maintenance of Station Equipment												
		STEP_UP	SG	3,852,358	248,293	3,604,065	-	-	-	-	-	-	-
		STEP_UP	SG	(248)	(16)	(232)	-	-	-	-	-	-	-
				3,852,111	248,277	3,603,833	-	-	-	-	-	-	-
571	Maintenance of Overhead Lines												
		T	SG	4,193,358	-	4,193,358	-	-	-	-	-	-	-
		T	SG	(2,378,532)	-	(2,378,532)	-	-	-	-	-	-	-
				1,814,826	-	1,814,826	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
572	Maintenance of Underground Lines												
		T	SG	44,430	-	44,430	-	-	-	-	-	-	-
		T	SG	(24)	-	(24)	-	-	-	-	-	-	-
				44,406	-	44,406	-	-	-	-	-	-	-
573	Maint of Misc. Transmission Plant												
		T	SG	25,561	-	25,561	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-	-
				25,561	-	25,561	-	-	-	-	-	-	-
TOTAL TRANSMISSION EXPENSE				**64,748,998**	**248,277**	**64,500,721**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
580	Operation Supervision & Engineering												
		D_SPLIT	S	1,483,689	-	-	1,407,697	15,779	-	-	60,213	-	-
		D_SPLIT	SNPD	3,798,276	-	-	3,603,735	40,395	-	-	154,146	-	-
				5,281,965	-	-	5,011,431	56,175	-	-	214,359	-	-
581	Load Dispatching												
		D	S	-	-	-	-	-	-	-	-	-	-
		D	SNPD	4,292,434	-	-	4,292,434	-	-	-	-	-	-
				4,292,434	-	-	4,292,434	-	-	-	-	-	-
582	Station Expense												
		D	S	1,137,499	-	-	1,137,499	-	-	-	-	-	-
		D	SNPD	131	-	-	131	-	-	-	-	-	-
				1,137,630	-	-	1,137,630	-	-	-	-	-	-
583	Overhead Line Expenses												
		D	S	2,684,199	-	-	2,684,199	-	-	-	-	-	-
		D	SNPD	-	-	-	-	-	-	-	-	-	-
				2,684,199	-	-	2,684,199	-	-	-	-	-	-
584	Underground Line Expense												
		D	S	-	-	-	-	-	-	-	-	-	-
		D	SNPD	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
585	Street Lighting & Signal Systems												
		DL	S	-	-	-	-	-	-	-	-	-	-
		DL	SNPD	75,142	-	-	-	75,142	-	-	-	-	-
				75,142	-	-	-	75,142	-	-	-	-	-
586	Meter Expenses												
		C_Meter	S	1,388,283	-	-	-	-	-	-	1,388,283	-	-
		C_Meter	SNPD	-	-	-	-	-	-	-	-	-	-
				1,388,283	-	-	-	-	-	-	1,388,283	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
587	Customer Installation Expenses												
		D	S	7,565,964	-	-	7,565,964	-	-	-	-	-	-
		D	SNPD	-	-	-	-	-	-	-	-	-	-
				7,565,964	-	-	7,565,964	-	-	-	-	-	-
588	Misc. Distribution Expenses												
		D	S	(296,944)	-	-	(296,944)	-	-	-	-	-	-
		D	SNPD	182,615	-	-	182,615	-	-	-	-	-	-
				(114,329)	-	-	(114,329)	-	-	-	-	-	-
589	Rents												
		D	S	1,871,412	-	-	1,871,412	-	-	-	-	-	-
		D	SNPD	101,222	-	-	101,222	-	-	-	-	-	-
				1,972,634	-	-	1,972,634	-	-	-	-	-	-
590	Maint Supervision & Engineering												
		D_SPLIT	S	1,028,357	-	-	975,686	10,937	-	-	41,734	-	-
		D_SPLIT	SNPD	836,083	-	-	793,260	8,892	-	-	33,931	-	-
				1,864,440	-	-	1,768,946	19,829	-	-	75,665	-	-
591	Maintenance of Structures												
		D	S	658,957	-	-	658,957	-	-	-	-	-	-
		D	SNPD	20,036	-	-	20,036	-	-	-	-	-	-
				678,993	-	-	678,993	-	-	-	-	-	-
592	Maintenance of Station Equipment												
		D	S	4,224,901	-	-	4,224,901	-	-	-	-	-	-
		D	SNPD	290,770	-	-	290,770	-	-	-	-	-	-
				4,515,671	-	-	4,515,671	-	-	-	-	-	-
593	Maintenance of Overhead Lines												
		D	S	70,302,494	-	-	70,302,494	-	-	-	-	-	-
		D	SNPD	842,729	-	-	842,729	-	-	-	-	-	-
				71,145,222	-	-	71,145,222	-	-	-	-	-	-
594	Maintenance of Underground Lines												
		D	S	9,446,513	-	-	9,446,513	-	-	-	-	-	-
		D	SNPD	2,422	-	-	2,422	-	-	-	-	-	-
				9,448,935	-	-	9,448,935	-	-	-	-	-	-
595	Maintenance of Line Transformers												
		D	S	-	-	-	-	-	-	-	-	-	-
		D	SNPD	272,218	-	-	272,218	-	-	-	-	-	-
				272,218	-	-	272,218	-	-	-	-	-	-
596	Maint of Street Lighting & Signal Sys.												
		DL	S	790,355	-	-	-	790,355	-	-	-	-	-
		DL	SNPD	-	-	-	-	-	-	-	-	-	-
				790,355	-	-	-	790,355	-	-	-	-	-
597	Maintenance of Meters												
		C_Meter	S	178,506	-	-	-	-	-	-	178,506	-	-
		C_Meter	SNPD	(6,481)	-	-	-	-	-	-	(6,481)	-	-
				172,025	-	-	-	-	-	-	172,025	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
598	Maint of Misc. Distribution Plant												
		D	S	667,240	-	-	667,240	-	-	-	-	-	-
		D	SNPD	869,157	-	-	869,157	-	-	-	-	-	-
				1,536,397	-	-	1,536,397	-	-	-	-	-	-
TOTAL DISTRIBUTION EXPENSE				**114,708,178**	**-**	**-**	**111,916,347**	**941,500**	**-**	**-**	**1,850,332**	**-**	**-**
901	Supervision												
		CUST901	S	-	-	-	-	-	-	-	-	-	-
		CUST901	CN	958,963	-	-	-	-	-	566,577	358,760	33,627	-
				958,963	-	-	-	-	-	566,577	358,760	33,627	-
902	Meter Reading Expense												
		C_Meter	S	2,093,427	-	-	-	-	-	-	2,093,427	-	-
		C_Meter	CN	234,949	-	-	-	-	-	-	234,949	-	-
				2,328,376	-	-	-	-	-	-	2,328,376	-	-
903	Customer Receipts & Collections												
		CUST903	S	5,419,367	-	-	-	-	-	4,119,186	227,573	1,072,608	-
		CUST903	CN	12,485,741	-	-	-	-	-	9,490,238	524,309	2,471,194	-
				17,905,108	-	-	-	-	-	13,609,423	751,882	3,543,802	-
904	Uncollectible Accounts												
		REVREQ	S	10,518,476	6,047,375	1,775,181	2,392,832	18,286	-	126,747	99,594	58,461	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		REVREQ	CN	(288,428)	(165,825)	(48,677)	(65,614)	(501)	-	(3,476)	(2,731)	(1,603)	-
				10,230,048	5,881,550	1,726,503	2,327,218	17,784	-	123,272	96,863	56,858	-
905	Misc. Customer Accounts Expense												
		CUST905	S	(0)	-	-	-	-	-	-	(0)	(0)	-
		CUST905	CN	47	-	-	-	-	-	-	30	18	-
				47	-	-	-	-	-	-	30	18	-
TOTAL CUSTOMER ACCOUNTS EXPENSE				**31,422,542**	**5,881,550**	**1,726,503**	**2,327,218**	**17,784**	**-**	**14,299,271**	**3,535,910**	**3,634,305**	**-**
907	Supervision												
		C_Service	S	-	-	-	-	-	-	-	-	-	-
		C_Service	CN	395	-	-	-	-	-	-	-	395	-
				395	-	-	-	-	-	-	-	395	-
908	Customer Assistance												
		DSM	S	2,480,719	-	-	2,480,719	-	-	-	-	-	-
		C_Service	CN	1,034,910	-	-	-	-	-	-	-	1,034,910	-
				3,515,629	-	-	2,480,719	-	-	-	-	1,034,910	-
909	Informational & Instructional Adv												
		C_Service	S	816,425	-	-	-	-	-	-	-	816,425	-
		C_Service	CN	972,906	-	-	-	-	-	-	-	972,906	-
				1,789,331	-	-	-	-	-	-	-	1,789,331	-
910	Misc. Customer Service												

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
		C_Service	S	-	-	-	-	-	-	-	-	-	-
		C_Service	CN	2,741	-	-	-	-	-	-	-	2,741	-
				2,741	-	-	-	-	-	-	-	2,741	-
TOTAL CUSTOMER SERVICE EXPENSE				**5,308,096**	**-**	**-**	**2,480,719**	**-**	**-**	**-**	**-**	**2,827,377**	**-**
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				**5,308,096**	**-**	**-**	**2,480,719**	**-**	**-**	**-**	**-**	**2,827,377**	**-**

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
920	Administrative & General Salaries												
		LABOR	S	91,689	38,398	6,626	36,099	273	-	6,211	1,817	2,265	-
		LABOR	CN	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	23,458,113	9,824,034	1,695,166	9,235,748	69,868	-	1,589,002	464,914	579,382	-
				23,549,802	9,862,432	1,701,792	9,271,847	70,141	-	1,595,213	466,731	581,646	-
921	Office Supplies & expenses												
		LABOR	S	(4,584)	(1,920)	(331)	(1,805)	(14)	-	(311)	(91)	(113)	-
		LABOR	CN	40,807	17,089	2,949	16,066	122	-	2,764	809	1,008	-
		LABOR	SO	5,070,467	2,123,463	366,410	1,996,305	15,102	-	343,463	100,491	125,233	-
				5,106,690	2,138,633	369,027	2,010,567	15,210	-	345,916	101,209	126,128	-
922	Office Supplies & expenses												
		LABOR	S	-	-	-	-	-	-	-	-	-	-
		LABOR	CN	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	(14,016,494)	(5,869,974)	(1,012,881)	(5,518,466)	(41,747)	-	(949,447)	(277,791)	(346,187)	-
				(14,016,494)	(5,869,974)	(1,012,881)	(5,518,466)	(41,747)	-	(949,447)	(277,791)	(346,187)	-
923	Outside Services												
		LABOR	S	865,859	362,614	62,570	340,899	2,579	-	58,651	17,160	21,385	-
		LABOR	CN	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	14,315,682	5,995,271	1,034,502	5,636,260	42,638	-	969,713	283,721	353,577	-
				15,181,541	6,357,885	1,097,072	5,977,160	45,217	-	1,028,365	300,881	374,962	-
924	Property Insurance												
		DPW	S	15,773,778	-	-	15,323,606	-	-	-	450,173	-	-
		PT	SG	-	-	-	-	-	-	-	-	-	-
		GP	SO	1,317,638	519,208	386,771	377,488	4,165	-	7,434	18,362	4,210	-
				17,091,416	519,208	386,771	15,701,094	4,165	-	7,434	468,535	4,210	-
925	Injuries & Damages												
		DPW	S	3,960,968	-	-	3,847,925	-	-	-	113,043	-	-
		LABOR	SO	4,415,850	1,849,316	319,105	1,738,575	13,152	-	299,120	87,517	109,065	-
				8,376,819	1,849,316	319,105	5,586,500	13,152	-	299,120	200,561	109,065	-
926	Employee Pensions & Benefits												
		LABOR	S	(5,733,248)	(2,401,029)	(414,305)	(2,257,250)	(17,076)	-	(388,358)	(113,627)	(141,603)	-
		LABOR	SG	797,657	334,051	57,641	314,047	2,376	-	54,032	15,809	19,701	-
		LABOR	SO	31,134,863	13,038,984	2,249,915	12,258,179	92,732	-	2,109,009	617,058	768,986	-
				26,199,272	10,972,005	1,893,252	10,314,976	78,032	-	1,774,682	519,240	647,084	-
927	Franchise Requirements												
		DSM	S	-	-	-	-	-	-	-	-	-	-
		DSM	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
928	Regulatory Commission Expense												
		D	S	8,126,600	-	-	8,126,600	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
		D	SO	475,120	-	-	475,120	-	-	-	-	-	-
		FERC	SG	1,750,313	856,312	894,001	-	-	-	-	-	-	-
				10,352,032	856,312	894,001	8,601,720	-	-	-	-	-	-
929	Duplicate Charges												

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
		LABOR	S	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	(37,329,652)	(15,633,302)	(2,697,572)	(14,697,144)	(111,183)	-	(2,528,630)	(739,832)	(921,989)	-
				(37,329,652)	(15,633,302)	(2,697,572)	(14,697,144)	(111,183)	-	(2,528,630)	(739,832)	(921,989)	-
930	Misc General Expenses												
		LABOR	S	(1,024,126)	(428,894)	(74,007)	(403,211)	(3,050)	-	(69,372)	(20,297)	(25,294)	-
		C_SERVICE	CN	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	540,113	226,194	39,030	212,649	1,609	-	36,586	10,704	13,340	-
				(484,014)	(202,700)	(34,977)	(190,562)	(1,442)	-	(32,786)	(9,593)	(11,954)	-
931	Rents												
		LABOR	S	333,350	139,604	24,089	131,244	993	-	22,580	6,607	8,233	-
		LABOR	SO	(1,185,930)	(496,656)	(85,699)	(466,915)	(3,532)	-	(80,332)	(23,504)	(29,291)	-
				(852,579)	(357,052)	(61,610)	(335,671)	(2,539)	-	(57,752)	(16,897)	(21,057)	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
935	Maintenance of General Plant												
		G	S	287,854	56,119	101,248	123,709	-	-	3,143	3,634	-	-
		B_Center	CN	10,987	-	-	-	-	-	7,158	-	3,830	-
		G	SO	8,139,050	1,586,771	2,862,779	3,497,874	-	-	88,866	102,760	-	-
				8,437,891	1,642,891	2,964,027	3,621,583	-	-	99,167	106,394	3,830	-
TOTAL ADMINISTRATIVE & GEN EXPENSE				**61,612,724**	**12,135,653**	**5,818,005**	**40,343,603**	**69,006**	**-**	**1,581,282**	**1,119,438**	**545,737**	**-**
TOTAL O&M EXPENSE				**1,130,053,083**	**870,518,025**	**72,045,230**	**157,067,885**	**1,028,290**	**-**	**15,880,553**	**6,505,679**	**7,007,420**	**-**
403SP	Steam Depreciation												
		P	SG	13,623,534	13,623,534	-	-	-	-	-	-	-	-
		P	SG	10,120,999	10,120,999	-	-	-	-	-	-	-	-
		P	SG	89,531,621	89,531,621	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				113,276,155	113,276,155	-	-	-	-	-	-	-	-
403NP	Nuclear Depreciation												
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
403HP	Hydro Depreciation												
		P	SG	4,125,749	4,125,749	-	-	-	-	-	-	-	-
		P	SG	354,012	354,012	-	-	-	-	-	-	-	-
		P	SG	5,553,577	5,553,577	-	-	-	-	-	-	-	-
		P	SG	2,517,771	2,517,771	-	-	-	-	-	-	-	-
		P	SG	(3,059,099)	(3,059,099)	-	-	-	-	-	-	-	-
				9,492,011	9,492,011	-	-	-	-	-	-	-	-
403OP	Other Production Depreciation												
		P	S	61,373	61,373	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	18,450,653	18,450,653	-	-	-	-	-	-	-	-
		P	SG	1,151,516	1,151,516	-	-	-	-	-	-	-	-
		P	SG	43,640,253	43,640,253	-	-	-	-	-	-	-	-
				63,303,795	63,303,795	-	-	-	-	-	-	-	-
403TP	Transmission Depreciation												
		T_Split	S	-	-	-	-	-	-	-	-	-	-
		T_Split	SG	2,218,391	34,605	2,183,786	-	-	-	-	-	-	-
		T_Split	SG	2,776,526	43,311	2,733,215	-	-	-	-	-	-	-
		T_Split	SG	47,093,349	734,616	46,358,732	-	-	-	-	-	-	-
				52,088,266	812,533	51,275,733	-	-	-	-	-	-	-
403	Distribution Depreciation												
360	Land & Land Rights	D	S	105,224	-	-	105,224	-	-	-	-	-	-
361	Structures	D	S	597,644	-	-	597,644	-	-	-	-	-	-
362	Station Equipment	D	S	7,130,257	-	-	7,130,257	-	-	-	-	-	-
363	Storage Battery Equ	D	S	-	-	-	-	-	-	-	-	-	-
364	Poles & Towers	D	S	16,461,953	-	-	16,461,953	-	-	-	-	-	-
365	OH Conductors	D	S	7,035,472	-	-	7,035,472	-	-	-	-	-	-
366	UG Conduit	D	S	2,251,044	-	-	2,251,044	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
367	UG Conductor	D	S	4,997,445	-	-	4,997,445	-	-	-	-	-	-
368	Line Trans	D	S	12,697,496	-	-	12,697,496	-	-	-	-	-	-
369	Services	D	S	7,632,164	-	-	7,632,164	-	-	-	-	-	-
370	Meters	C_Meter	S	1,898,629	-	-	-	-	-	-	1,898,629	-	-
371	Inst Cust Prem	DL	S	119,651	-	-	-	119,651	-	-	-	-	-
372	Leased Property	D	S	-	-	-	-	-	-	-	-	-	-
373	Street Lighting	DL	S	643,654	-	-	-	643,654	-	-	-	-	-
				61,570,633	-	-	58,908,698	763,305	-	-	1,898,629	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
403GP	General Depreciation												
		TD	S	6,424,180	-	3,392,174	3,032,006	-	-	-	-	-	-
		G-DGP	SG	1,758	981	776	-	-	-	-	-	-	-
		G-DGU	SG	9,338	5,214	4,125	-	-	-	-	-	-	-
		P	SE	29,716	29,716	-	-	-	-	-	-	-	-
		B_Center	CN	217,934	-	-	-	-	-	141,972	-	75,962	-
		G-SG	SG	3,022,207	1,202,153	1,820,054	-	-	-	-	-	-	-
		LABOR	SO	7,639,251	3,199,245	552,039	3,007,667	22,753	-	517,466	151,401	188,678	-
		P	SG	2,441	2,441	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				17,346,823	4,439,750	5,769,168	6,039,673	22,753	-	659,438	151,401	264,640	-
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				**317,077,683**	**191,324,243**	**57,044,901**	**64,948,371**	**786,058**	**-**	**659,438**	**2,050,031**	**264,640**	**-**
404GP	Amort of LT Plant - Capital Lease Gen												
		TD	S	139,579	-	73,702	65,877	-	-	-	-	-	-
		I-SG	SG	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	11,344	4,751	820	4,466	34	-	768	225	280	-
		I-DGU	SG	-	-	-	-	-	-	-	-	-	-
		B_Center	CN	-	-	-	-	-	-	-	-	-	-
		I-DGP	SG	-	-	-	-	-	-	-	-	-	-
				150,923	4,751	74,522	70,343	34	-	768	225	280	-
404SP	Amort of LT Plant - Cap Lease Steam												
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
404IP	Amort of LT Plant - Intangible Plant												
		TD	S	11,216	-	5,922	5,294	-	-	-	-	-	-
		P	SE	248	248	-	-	-	-	-	-	-	-
		I-SG	SG	1,562,768	993,603	569,165	-	-	-	-	-	-	-
		LABOR	SO	14,013,506	5,868,723	1,012,665	5,517,290	41,738	-	949,245	277,732	346,113	-
		CSS_SYS	CN	4,785,713	-	-	-	-	-	2,121,666	1,116,666	1,547,381	-
		I-SG	SG	720,638	458,179	262,459	-	-	-	-	-	-	-
		I-SG	SG	84,585	53,779	30,806	-	-	-	-	-	-	-
		I-DGP	SG	21,143	21,143	-	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
		I-SG	SG	-	-	-	-	-	-	-	-	-	-
		I-SG	SG	-	-	-	-	-	-	-	-	-	-
		I-DGU	SG	3,353	3,353	-	-	-	-	-	-	-	-
				21,203,170	7,399,027	1,881,018	5,522,583	41,738	-	3,070,911	1,394,399	1,893,494	-
404MP	Amort of LT Plant - Mining Plant												
		P	SE	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
404OP	Amort of LT Plant - Other Plant												
		P	S	70,641	70,641	-	-	-	-	-	-	-	-
				70,641	70,641	-	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
404HP	Amortization of Other Electric Plant												
		P	SG	84,383	84,383	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				84,383	84,383	-	-	-	-	-	-	-	-
Total Amortization of Limited Term Plant				**21,509,117**	**7,558,802**	**1,955,540**	**5,592,926**	**41,772**	**-**	**3,071,679**	**1,394,623**	**1,893,774**	**-**
405	Amortization of Other Electric Plant												
		GP	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
406	Amortization of Plant Acquisition Adj												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	20,258	20,258	-	-	-	-	-	-	-	-
		P	SO	-	-	-	-	-	-	-	-	-	-
				20,258	20,258	-	-	-	-	-	-	-	-
407	Amort of Prop Losses, Unrec Plant, etc												
		DPW	S	8,855,708	-	-	8,602,972	-	-	-	252,736	-	-
		GP	SO	-	-	-	-	-	-	-	-	-	-
		P	SG	519,760	519,760	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	TROJP	-	-	-	-	-	-	-	-	-	-
				9,375,468	519,760	-	8,602,972	-	-	-	252,736	-	-
TOTAL AMORTIZATION EXPENSE				**30,904,843**	**8,098,820**	**1,955,540**	**14,195,898**	**41,772**	**-**	**3,071,679**	**1,647,359**	**1,893,774**	**-**
408	Taxes Other Than Income												
		D	S	45,708,476	-	-	45,708,476	-	-	-	-	-	-
		GP	GPS	49,277,803	19,417,639	14,464,692	14,117,522	155,762	-	278,015	686,729	157,444	-
		REVREQ	SO	4,232,970	2,433,656	714,389	962,952	7,359	-	51,007	40,080	23,527	-
		P	SE	317,499	317,499	-	-	-	-	-	-	-	-
		P	SG	1,036,056	1,036,056	-	-	-	-	-	-	-	-
		DSM	OPRV-ID	-	-	-	-	-	-	-	-	-	-
		GP	EXCTAX	-	-	-	-	-	-	-	-	-	-
		GP	SG	-	-	-	-	-	-	-	-	-	-
				100,572,803	23,204,851	15,179,081	60,788,950	163,121	-	329,022	726,809	180,970	-
41140	Deferred Investment Tax Credit - Fed												
		PTD	DGU	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
41141	Deferred Investment Tax Credit - Idaho												
		PTD	DGU	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
TOTAL DEFERRED ITC				-	-	-	-	-	-	-	-	-	-
427	Interest on Long-Term Debt												
		NP	S	140,183,903	44,842,608	53,262,109	38,732,606	387,158	-	615,629	2,087,292	256,500	-
		NP	SNP	-	-	-	-	-	-	-	-	-	-
				140,183,903	44,842,608	53,262,109	38,732,606	387,158	-	615,629	2,087,292	256,500	-
428	Amortization of Debt Disc & Exp												
		NP	SNP	1,328,071	424,829	504,593	366,944	3,668	-	5,832	19,775	2,430	-
				1,328,071	424,829	504,593	366,944	3,668	-	5,832	19,775	2,430	-
429	Amortization of Premium on Debt												
		NP	SNP	(414)	(133)	(157)	(115)	(1)	-	(2)	(6)	(1)	-
				(414)	(133)	(157)	(115)	(1)	-	(2)	(6)	(1)	-
431	Other Interest Expense												
		NUTIL	OTH	-	-	-	-	-	-	-	-	-	-
		GP	SO	-	-	-	-	-	-	-	-	-	-
		NP	SNP	8,172,894	2,614,379	3,105,246	2,258,158	22,572	-	35,892	121,692	14,954	-
				8,172,894	2,614,379	3,105,246	2,258,158	22,572	-	35,892	121,692	14,954	-
432	AFUDC - Borrowed												
		NP	SNP	(12,419,040)	(3,972,654)	(4,718,547)	(3,431,363)	(34,299)	-	(54,539)	(184,915)	(22,724)	-
				(12,419,040)	(3,972,654)	(4,718,547)	(3,431,363)	(34,299)	-	(54,539)	(184,915)	(22,724)	-
	Total Electric Interest Deductions for Tax			137,265,413	43,909,030	52,153,245	37,926,231	379,098	-	602,812	2,043,837	251,160	-
	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			137,265,413	43,909,030	52,153,245	37,926,231	379,098	-	602,812	2,043,837	251,160	-
419	Interest & Dividends												
		GP	S	-	-	-	-	-	-	-	-	-	-
		GP	SNP	(65,590,851)	(25,845,704)	(19,253,120)	(18,791,022)	(207,327)	-	(370,050)	(914,065)	(209,564)	-
	Total Operating Deductions for Tax			(65,590,851)	(25,845,704)	(19,253,120)	(18,791,022)	(207,327)	-	(370,050)	(914,065)	(209,564)	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
41010	Deferred Income Tax - Federal-DR												
		GP	S	(309,582)	(121,989)	(90,873)	(88,692)	(979)	-	(1,747)	(4,314)	(989)	-
		P	CHMDEX	-	-	-	-	-	-	-	-	-	-
		PT	SG	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	178,417	74,720	12,893	70,245	531	-	12,086	3,536	4,407	-
		NP	SNP	23,454,306	7,502,661	8,911,335	6,480,390	64,776	-	103,002	349,227	42,915	-
		P	SE	4,202	4,202	-	-	-	-	-	-	-	-
		PT	SG	10,295,739	5,748,698	4,547,042	-	-	-	-	-	-	-
		GP	GPS	3,147,512	1,240,259	923,900	901,726	9,949	-	17,758	43,863	10,056	-
		TAXDEPR	TAXDEPR	90,338,073	39,348,590	25,471,400	23,527,116	31,559	-	775,675	682,594	501,139	-
		C_BILLING	BADDEBT	-	-	-	-	-	-	-	-	-	-
		CSS_SYS	CN	-	-	-	-	-	-	-	-	-	-
		IBT	IBT	-	-	-	-	-	-	-	-	-	-
		D	SNPD	-	-	-	-	-	-	-	-	-	-
				127,108,667	53,797,140	39,775,698	30,890,786	105,836	-	906,774	1,074,906	557,528	-
41110	Deferred Income Tax - Federal-CR												
		GP	S	(17,534,021)	(6,909,182)	(5,146,824)	(5,023,295)	(55,423)	-	(98,923)	(244,352)	(56,022)	-
		P	SE	(963,569)	(963,569)	-	-	-	-	-	-	-	-
		C_BILLING	BADDEBT	(0)	-	-	-	-	-	(0)	-	-	-
		NP	SNP	(13,937,921)	(4,458,520)	(5,295,637)	(3,851,027)	(38,494)	-	(61,210)	(207,531)	(25,503)	-
		PT	SG	-	-	-	-	-	-	-	-	-	-
		D_SPLIT	CIAC	(9,236,961)	-	-	(8,763,859)	(98,236)	-	-	(374,865)	-	-
		LABOR	SO	(3,813,604)	(1,597,101)	(275,584)	(1,501,463)	(11,358)	-	(258,325)	(75,581)	(94,191)	-
		D	SNPD	-	-	-	-	-	-	-	-	-	-
		CSS_SYS	CN	6,702	-	-	-	-	-	2,971	1,564	2,167	-
		P	SGCT	-	-	-	-	-	-	-	-	-	-
		BOOKDEPR	CHMDEX	(71,931,536)	(43,818,759)	(11,141,787)	(16,234,458)	(196,414)	-	(63,187)	(476,931)	-	-
		P	TROJD	-	-	-	-	-	-	-	-	-	-
		IBT	IBT	-	-	-	-	-	-	-	-	-	-
		P	SG	(14,634,969)	(14,634,969)	-	-	-	-	-	-	-	-
		GP	GPS	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				(132,045,879)	(72,382,100)	(21,859,833)	(35,374,101)	(399,926)	-	(478,673)	(1,377,697)	(173,548)	-
TOTAL DEFERRED INCOME TAXES				(4,937,211)	(18,584,960)	17,915,865	(4,483,316)	(294,090)	-	428,100	(302,791)	383,980	-
SCHMAF	Additions - Flow Through												
		SCHMAF	S	-	-	-	-	-	-	-	-	-	-
		SCHMAF	SNP	-	-	-	-	-	-	-	-	-	-
		SCHMAF	SO	-	-	-	-	-	-	-	-	-	-
		SCHMAF	SE	-	-	-	-	-	-	-	-	-	-
		P	TROJP	-	-	-	-	-	-	-	-	-	-
		SCHMAF	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
SCHMAP	Additions - Permanent												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SE	3,953	3,953	-	-	-	-	-	-	-	-
		PTD	SNP	-	-	-	-	-	-	-	-	-	-
		SCHMAP-SO	SO	520,374	327,647	23,962	130,553	988	-	22,462	6,572	8,190	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
		SCHMAP	SG	-	-	-	-	-	-	-	-	-	-
		BOOKDEPR	CHMDEX	35,183	21,432	5,450	7,941	96	-	31	233	-	-
				559,509	353,033	29,412	138,494	1,084	-	22,492	6,805	8,190	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
SCHMAT	Additions - Temporary												
		SCHMAT-SITU	S	21,050,906	12,468,624	2,748,609	4,956,524	20,875	-	474,763	208,403	173,108	-
		SCHMAT-SG	GPS	-	-	-	-	-	-	-	-	-	-
		D_SPLIT	CIAC	37,569,085	-	-	35,644,859	399,553	-	-	1,524,673	-	-
		SCHMAT-SNP	SNP	56,689,096	25,322,437	15,132,853	15,769,087	-	-	674	463,584	461	-
		P	TROJD	-	-	-	-	-	-	-	-	-	-
		C_BILLING	BADDEBT	0	-	-	-	-	-	0	-	-	-
		SCHMAT-SE	SE	3,919,087	4,019,851	(12,528)	(68,257)	(516)	-	(11,744)	(3,436)	(4,282)	-
		SCHMAT-SG	GPS	-	-	-	-	-	-	-	-	-	-
		CSS_SYS	CN	(27,260)	-	-	-	-	-	(12,085)	(6,361)	(8,814)	-
		SCHMAT-SO	SO	10,928,291	4,574,506	774,688	4,311,524	32,779	-	745,488	217,486	271,820	-
		SCHMAT-SNP	SNPD	-	-	-	-	-	-	-	-	-	-
		P	SGCT	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		BOOKDEPR	SCHMDEX	292,563,984	178,222,118	45,316,500	66,029,699	798,868	-	256,996	1,939,802	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	11,286,610	11,286,610	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				433,979,799	235,894,146	63,960,122	126,643,436	1,251,558	-	1,454,092	4,344,152	432,293	-
TOTAL SCHEDULE - M ADDITIONS				434,539,308	236,247,179	63,989,534	126,781,929	1,252,642	-	1,476,585	4,350,957	440,483	-
SCHMDF	Deductions - Flow Through												
		SCHMDF	S	-	-	-	-	-	-	-	-	-	-
		SCHMDF	SG	-	-	-	-	-	-	-	-	-	-
		SCHMDF	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
SCHMDP	Deductions - Permanent												
		SCHMDP	S	-	-	-	-	-	-	-	-	-	-
		P	SE	151,388	151,388	-	-	-	-	-	-	-	-
		SCHMDP	SNP	28,210	27,722	235	245	-	-	-	7	-	-
		BOOKDEPR	SCHMDEX	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		SCHMDP-SO	SO	-	-	-	-	-	-	-	-	-	-
				179,597	179,110	235	245	-	-	-	7	-	-
SCHMDT	Deductions - Temporary												
		SCHMDT-SITU	S	(1,259,158)	(1,314,632)	11,670	41,766	45	-	1,085	496	412	-
		SCHMDT	BADDEBT	-	-	-	-	-	-	-	-	-	-
		SCHMDT-SNP	SNP	95,394,668	42,617,032	25,464,097	26,534,030	-	-	-	779,509	-	-
		SCHMDT	CN	-	-	-	-	-	-	-	-	-	-
		SCHMDT-SG	SG	-	-	-	-	-	-	-	-	-	-
		SCHMDT-SG	SG	41,875,413	43,016,005	(1,140,592)	-	-	-	-	-	-	-
		P	SE	17,092	17,092	-	-	-	-	-	-	-	-
		SCHMDT-SG	SG	-	-	-	-	-	-	-	-	-	-
		SCHMDT-GPS	GPS	12,801,734	5,719,103	3,417,220	3,560,803	-	-	-	104,608	-	-
		SCHMDT-SO	SO	725,671	304,691	(12,463)	306,352	3,357	-	76,274	19,671	27,789	-
		TAXDEPR	TAXDEPR	367,428,084	160,040,796	103,598,708	95,690,808	128,357	-	3,154,871	2,776,286	2,038,259	-
		SCHMDT-SNP	SNPD	(0)	(0)	(0)	(0)	-	-	-	(0)	-	-
				516,983,504	250,400,087	131,338,641	126,133,758	131,759	-	3,232,230	3,680,570	2,066,460	-
TOTAL SCHEDULE - M DEDUCTIONS				517,163,102	250,579,196	131,338,877	126,134,003	131,759	-	3,232,230	3,680,577	2,066,460	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
TOTAL SCHEDULE - M ADJUSTMENTS				(82,623,793)	(14,332,017)	(67,349,343)	647,926	1,120,883	-	(1,755,645)	670,380	(1,625,977)	-
40911	State Income Taxes												
		REVREQ		5,088,036	2,925,259	858,697	1,157,469	8,845	-	61,311	48,176	28,279	-
		REVREQ	S	219,094	125,963	36,976	49,841	381	-	2,640	2,074	1,218	-
	PTC	P	SG	-	-	-	-	-	-	-	-	-	-
		IBT	IBT	-	-	-	-	-	-	-	-	-	-
TOTAL STATE TAXES				5,307,130	3,051,222	895,673	1,207,311	9,226	-	63,951	50,251	29,497	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
Calculation of Taxable Income:													
	Operating Revenues			1,844,948,033	1,060,713,897	311,367,927	419,704,344	3,207,315	-	22,231,523	17,468,923	10,254,105	-
	Operating Deductions:												
	O & M Expenses			1,130,053,083	870,518,025	72,045,230	157,067,885	1,028,290	-	15,880,553	6,505,679	7,007,420	-
	Depreciation Expense			317,077,683	191,324,243	57,044,901	64,948,371	786,058	-	659,438	2,050,031	264,640	-
	Amortization Expense			30,904,843	8,098,820	1,955,540	14,195,898	41,772	-	3,071,679	1,647,359	1,893,774	-
	Taxes Other Than Income			100,572,803	23,204,851	15,179,081	60,788,950	163,121	-	329,022	726,809	180,970	-
	Interest & Dividends (AFUDC-Equity)			(65,590,851)	(25,845,704)	(19,253,120)	(18,791,022)	(207,327)	-	(370,050)	(914,065)	(209,564)	-
	Misc Revenue & Expense			(30,006)	(92,792)	(9,553)	72,340	-	-	-	-	-	-
	Total Operating Deductions			1,512,987,554	1,067,207,442	126,962,078	278,282,423	1,811,914	-	19,570,643	10,015,813	9,137,240	-
	Other Deductions:												
	Interest Deductions			137,265,413	43,909,030	52,153,245	37,926,231	379,098	-	602,812	2,043,837	251,160	-
	Interest on PCRBS			-	-	-	-	-	-	-	-	-	-
	Schedule M Adjustments			(82,623,793)	(14,332,017)	(67,349,343)	647,926	1,120,883	-	(1,755,645)	670,380	(1,625,977)	-
	Income Before State Taxes			112,071,272	(64,734,592)	64,903,262	104,143,616	2,137,185	-	302,422	6,079,653	(760,273)	-
	State Income Taxes			5,307,130	3,051,222	895,673	1,207,311	9,226	-	63,951	50,251	29,497	-
Total Taxable Income				106,764,142	(67,785,814)	64,007,589	102,936,305	2,127,959	-	238,471	6,029,402	(789,770)	-
Tax Rate				0	0	0	0	0	0	0	0	0	0
Federal Income Tax - Calculated				22,420,470	(14,235,021)	13,441,594	21,616,624	446,871	-	50,079	1,266,174	(165,852)	-
Adjustments to Calculated Tax:													
40910	PMI	P	SE	(3,951)	(3,951)	-	-	-	-	-	-	-	-
40910	Renewable Energy (	P	SG	(65,202,036)	(65,202,036)	-	-	-	-	-	-	-	-
40910		P	SO	(9,163)	(9,163)	-	-	-	-	-	-	-	-
40910		P	S	-	-	-	-	-	-	-	-	-	-
Federal Income Tax				(42,794,680)	(79,450,171)	13,441,594	21,616,624	446,871	-	50,079	1,266,174	(165,852)	-
TOTAL OPERATING EXPENSES				**1,536,153,644**	**998,069,238**	**178,468,330**	**315,414,063**	**2,181,248**	**-**	**20,482,823**	**11,943,512**	**9,594,430**	**-**
310	Land and Land Rights												
		P	SG	625,603	625,603	-	-	-	-	-	-	-	-
		P	SG	9,078,654	9,078,654	-	-	-	-	-	-	-	-
		P	SG	14,611,953	14,611,953	-	-	-	-	-	-	-	-
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SG	340,582	340,582	-	-	-	-	-	-	-	-
				24,656,792	24,656,792	-	-	-	-	-	-	-	-
311	Structures and Improvements												
		P	SG	60,593,953	60,593,953	-	-	-	-	-	-	-	-
		P	SG	83,636,058	83,636,058	-	-	-	-	-	-	-	-
		P	SG	126,777,211	126,777,211	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				271,007,222	271,007,222	-	-	-	-	-	-	-	-
312	Boiler Plant Equipment												
		P	SG	157,159,755	157,159,755	-	-	-	-	-	-	-	-
		P	SG	124,342,847	124,342,847	-	-	-	-	-	-	-	-
		P	SG	943,094,422	943,094,422	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
				1,224,597,024	1,224,597,024	-	-	-	-	-	-	-	-
314	Turbogenerator Units												
		P	SG	29,135,609	29,135,609	-	-	-	-	-	-	-	-
		P	SG	28,630,467	28,630,467	-	-	-	-	-	-	-	-
		P	SG	209,310,389	209,310,389	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				267,076,465	267,076,465	-	-	-	-	-	-	-	-
315	Accessory Electric Equipment												
		P	SG	23,035,108	23,035,108	-	-	-	-	-	-	-	-
		P	SG	35,774,993	35,774,993	-	-	-	-	-	-	-	-
		P	SG	56,398,152	56,398,152	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				115,208,253	115,208,253	-	-	-	-	-	-	-	-
316	Misc Power Plant Equipment												
		P	SG	631,332	631,332	-	-	-	-	-	-	-	-
		P	SG	1,293,918	1,293,918	-	-	-	-	-	-	-	-
		P	SG	7,206,889	7,206,889	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				9,132,139	9,132,139	-	-	-	-	-	-	-	-
317	Steam Plant ARO												
		P	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
SP	Unclassified Steam Plant - Account 300												
		P	SG	4,782,433	4,782,433	-	-	-	-	-	-	-	-
				4,782,433	4,782,433	-	-	-	-	-	-	-	-
Total Steam Production Plant				**1,916,460,328**	**1,916,460,328**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
320	Land and Land Rights												
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
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	2,644,542	2,644,542	-	-	-	-	-	-	-	-
		P	SG	1,415,443	1,415,443	-	-	-	-	-	-	-	-
		P	SG	5,924,179	5,924,179	-	-	-	-	-	-	-	-
		P	SG	358,466	358,466	-	-	-	-	-	-	-	-
				10,342,631	10,342,631	-	-	-	-	-	-	-	-
331	Structures and Improvements												
		P	SG	4,079,017	4,079,017	-	-	-	-	-	-	-	-
		P	SG	1,277,614	1,277,614	-	-	-	-	-	-	-	-
		P	SG	65,964,688	65,964,688	-	-	-	-	-	-	-	-
		P	SG	4,669,579	4,669,579	-	-	-	-	-	-	-	-
				75,990,898	75,990,898	-	-	-	-	-	-	-	-
332	Reservoirs, Dams & Waterways												
		P	SG	33,938,250	33,938,250	-	-	-	-	-	-	-	-
		P	SG	5,019,638	5,019,638	-	-	-	-	-	-	-	-
		P	SG	102,845,475	102,845,475	-	-	-	-	-	-	-	-
		P	SG	31,689,163	31,689,163	-	-	-	-	-	-	-	-
		P	SG	(355,300)	(355,300)	-	-	-	-	-	-	-	-
				173,137,226	173,137,226	-	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
333	Water Wheel, Turbines, & Generators												
		P	SG	6,855,366	6,855,366	-	-	-	-	-	-	-	-
		P	SG	1,798,769	1,798,769	-	-	-	-	-	-	-	-
		P	SG	14,463,480	14,463,480	-	-	-	-	-	-	-	-
		P	SG	11,988,643	11,988,643	-	-	-	-	-	-	-	-
				35,106,257	35,106,257	-	-	-	-	-	-	-	-
334	Accessory Electric Equipment												
		P	SG	748,052	748,052	-	-	-	-	-	-	-	-
		P	SG	896,830	896,830	-	-	-	-	-	-	-	-
		P	SG	14,931,325	14,931,325	-	-	-	-	-	-	-	-
		P	SG	3,060,519	3,060,519	-	-	-	-	-	-	-	-
				19,636,726	19,636,726	-	-	-	-	-	-	-	-
335	Misc. Power Plant Equipment												
		P	SG	261,780	261,780	-	-	-	-	-	-	-	-
		P	SG	40,548	40,548	-	-	-	-	-	-	-	-
		P	SG	402,544	402,544	-	-	-	-	-	-	-	-
		P	SG	16,494	16,494	-	-	-	-	-	-	-	-
				721,366	721,366	-	-	-	-	-	-	-	-
336	Roads, Railroads & Bridges												
		P	SG	866,152	866,152	-	-	-	-	-	-	-	-
		P	SG	197,437	197,437	-	-	-	-	-	-	-	-
		P	SG	4,866,411	4,866,411	-	-	-	-	-	-	-	-
		P	SG	955,018	955,018	-	-	-	-	-	-	-	-
				6,885,019	6,885,019	-	-	-	-	-	-	-	-
337	Hydro Plant ARO												
		P	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
HP	Unclassified Hydro Plant - Acct 300												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
Total Hydraulic Plant				**321,820,122**	**321,820,122**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
340	Land and Land Rights												
		P	S	74,986	74,986	-	-	-	-	-	-	-	-
		P	SG	10,490,871	10,490,871	-	-	-	-	-	-	-	-
		P	SG	3,638,315	3,638,315	-	-	-	-	-	-	-	-
		P	SG	63,213	63,213	-	-	-	-	-	-	-	-
				14,267,385	14,267,385	-	-	-	-	-	-	-	-
341	Structures and Improvements												
		P	S	3,756	3,756	-	-	-	-	-	-	-	-
		P	SG	45,093,476	45,093,476	-	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	27,047,066	27,047,066	-	-	-	-	-	-	-	-
		P	SG	1,148,760	1,148,760	-	-	-	-	-	-	-	-
				73,293,058	73,293,058	-	-	-	-	-	-	-	-
342	Fuel Holders, Producers & Accessories												
		P	SG	3,669,749	3,669,749	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	749,832	749,832	-	-	-	-	-	-	-	-
				4,419,581	4,419,581	-	-	-	-	-	-	-	-
343	Prime Movers												
		P	S	370,052	370,052	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	944,618,365	944,618,365	-	-	-	-	-	-	-	-
		P	SG	249,367,526	249,367,526	-	-	-	-	-	-	-	-
		P	SG	16,431,589	16,431,589	-	-	-	-	-	-	-	-
				1,210,787,532	1,210,787,532	-	-	-	-	-	-	-	-
344	Generators												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SG	44,415,479	44,415,479	-	-	-	-	-	-	-	-
		P	SG	108,382,133	108,382,133	-	-	-	-	-	-	-	-
		P	SG	4,785,333	4,785,333	-	-	-	-	-	-	-	-
				157,582,946	157,582,946	-	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
345	Accessory Electric Plant												
		P	S	516,566	516,566	-	-	-	-	-	-	-	-
		P	SG	53,612,432	53,612,432	-	-	-	-	-	-	-	-
		P	SG	66,576,326	66,576,326	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	780,042	780,042	-	-	-	-	-	-	-	-
				121,485,366	121,485,366	-	-	-	-	-	-	-	-
346	Misc. Power Plant Equipment												
		P	SG	3,311,693	3,311,693	-	-	-	-	-	-	-	-
		P	SG	3,189,422	3,189,422	-	-	-	-	-	-	-	-
				6,501,114	6,501,114	-	-	-	-	-	-	-	-
347	Other Production ARO												
		P	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
OP	Unclassified Other Prod Plant-Acct 300												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
Total Other Production Plant				**1,588,336,982**	**1,588,336,982**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Experimental Plant													
103	Experimental Plant												
		P	SG	-	-	-	-	-	-	-	-	-	-
Total Experimental Plant				**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
TOTAL PRODUCTION PLANT				**3,826,617,433**	**3,826,617,433**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
350	Land and Land Rights												
		T	SG	5,486,720	-	5,486,720	-	-	-	-	-	-	-
		T	SG	12,491,637	-	12,491,637	-	-	-	-	-	-	-
		T	SG	75,262,894	-	75,262,894	-	-	-	-	-	-	-
				93,241,252	-	93,241,252	-	-	-	-	-	-	-
352	Structures and Improvements												
		T	S	-	-	-	-	-	-	-	-	-	-
		T	SG	1,856,223	-	1,856,223	-	-	-	-	-	-	-
		T	SG	4,676,439	-	4,676,439	-	-	-	-	-	-	-
		T	SG	97,272,119	-	97,272,119	-	-	-	-	-	-	-
				103,804,780	-	103,804,780	-	-	-	-	-	-	-
353	Station Equipment												
		STEP_UP	SG	27,481,938	1,771,274	25,710,663	-	-	-	-	-	-	-
		STEP_UP	SG	39,242,560	2,529,274	36,713,286	-	-	-	-	-	-	-
		STEP_UP	SG	665,825,231	42,913,977	622,911,254	-	-	-	-	-	-	-
				732,549,729	47,214,525	685,335,204	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
354	Towers and Fixtures												
		T	SG	34,440,254	-	34,440,254	-	-	-	-	-	-	-
		T	SG	35,264,886	-	35,264,886	-	-	-	-	-	-	-
		T	SG	340,548,450	-	340,548,450	-	-	-	-	-	-	-
				410,253,591	-	410,253,591	-	-	-	-	-	-	-
355	Poles and Fixtures												
		T	S	-	-	-	-	-	-	-	-	-	-
		T	SG	15,721,805	-	15,721,805	-	-	-	-	-	-	-
		T	SG	30,308,612	-	30,308,612	-	-	-	-	-	-	-
		T	SG	1,150,049,256	-	1,150,049,256	-	-	-	-	-	-	-
				1,196,079,673	-	1,196,079,673	-	-	-	-	-	-	-
356	Clearing and Grading												
		T	SG	42,117,472	-	42,117,472	-	-	-	-	-	-	-
		T	SG	41,979,966	-	41,979,966	-	-	-	-	-	-	-
		T	SG	366,510,019	-	366,510,019	-	-	-	-	-	-	-
				450,607,457	-	450,607,457	-	-	-	-	-	-	-
357	Underground Conduit												
		T	SG	1,713	-	1,713	-	-	-	-	-	-	-
		T	SG	24,639	-	24,639	-	-	-	-	-	-	-
		T	SG	1,014,868	-	1,014,868	-	-	-	-	-	-	-
				1,041,220	-	1,041,220	-	-	-	-	-	-	-
358	Underground Conductors												
		T	SG	-	-	-	-	-	-	-	-	-	-
		T	SG	292,379	-	292,379	-	-	-	-	-	-	-
		T	SG	2,148,868	-	2,148,868	-	-	-	-	-	-	-
				2,441,247	-	2,441,247	-	-	-	-	-	-	-
359	Roads and Trails												
		T	SG	500,860	-	500,860	-	-	-	-	-	-	-
		T	SG	117,206	-	117,206	-	-	-	-	-	-	-
		T	SG	2,646,065	-	2,646,065	-	-	-	-	-	-	-
				3,264,131	-	3,264,131	-	-	-	-	-	-	-
TP	Unclassified Trans Plant - Acct 300												
		T	SG	33,452,905	-	33,452,905	-	-	-	-	-	-	-
				33,452,905	-	33,452,905	-	-	-	-	-	-	-
TS0	Unclassified Trans Sub Plant - Acct 300												
		T	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
TOTAL TRANSMISSION PLANT				**3,026,735,986**	**47,214,525**	**2,979,521,461**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
360	Land and Land Rights												
		D	S	16,501,049	-	-	16,501,049	-	-	-	-	-	-
				16,501,049	-	-	16,501,049	-	-	-	-	-	-
361	Structures and Improvements												
		D	S	36,865,601	-	-	36,865,601	-	-	-	-	-	-
				36,865,601	-	-	36,865,601	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
362	Station Equipment												
		D	S	321,458,778	-	-	321,458,778	-	-	-	-	-	-
				321,458,778	-	-	321,458,778	-	-	-	-	-	-
363	Storage Battery Equipment												
		D	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
364	Poles, Towers & Fixtures												
		D	S	537,021,123	-	-	537,021,123	-	-	-	-	-	-
				537,021,123	-	-	537,021,123	-	-	-	-	-	-
365	Overhead Conductors												
		D	S	326,142,454	-	-	326,142,454	-	-	-	-	-	-
				326,142,454	-	-	326,142,454	-	-	-	-	-	-
366	Underground Conduit												
		D	S	127,274,252	-	-	127,274,252	-	-	-	-	-	-
				127,274,252	-	-	127,274,252	-	-	-	-	-	-
367	Underground Conductors												
		D	S	249,806,557	-	-	249,806,557	-	-	-	-	-	-
				249,806,557	-	-	249,806,557	-	-	-	-	-	-
368	Line Transformers												
		D	S	553,956,506	-	-	553,956,506	-	-	-	-	-	-
				553,956,506	-	-	553,956,506	-	-	-	-	-	-
369	Services												
		D	S	373,239,647	-	-	373,239,647	-	-	-	-	-	-
				373,239,647	-	-	373,239,647	-	-	-	-	-	-
370	Meters												
		C_Meter	S	109,792,499	-	-	-	-	-	-	109,792,499	-	-
				109,792,499	-	-	-	-	-	-	109,792,499	-	-
371	Installations on Customers' Premises												
		DL	S	2,803,509	-	-	-	2,803,509	-	-	-	-	-
				2,803,509	-	-	-	2,803,509	-	-	-	-	-
372	Leased Property												
		D	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
373	Street Lights												
		DL	S	25,968,508	-	-	-	25,968,508	-	-	-	-	-
				25,968,508	-	-	-	25,968,508	-	-	-	-	-
DP	Unclassified Dist Plant - Acct 300												
		D	S	24,538,568	-	-	24,538,568	-	-	-	-	-	-
				24,538,568	-	-	24,538,568	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
DS0	Unclassified Dist Sub Plant - Acct 300												
		D	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
TOTAL DISTRIBUTION PLANT				**2,705,369,051**	**-**	**-**	**2,566,804,536**	**28,772,017**	**-**	**-**	**109,792,499**	**-**	**-**

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
389	Land and Land Rights												
		D_SPLIT	S	6,116,556	-	-	5,803,276	65,051	-	-	248,229	-	-
		B_Center	CN	346,514	-	-	-	-	-	225,735	-	120,779	-
		G-DGU	SG	89	50	39	-	-	-	-	-	-	-
		G-SG	SG	330	131	199	-	-	-	-	-	-	-
		LABOR	SO	2,087,521	874,234	150,852	821,883	6,217	-	141,404	41,372	51,559	-
				8,551,011	874,415	151,090	6,625,159	71,268	-	367,139	289,602	172,338	-
390	Structures and Improvements												
		D_SPLIT	S	44,350,073	-	-	42,078,536	471,670	-	-	1,799,867	-	-
		P	SE	247,839	247,839	-	-	-	-	-	-	-	-
		G-DGP	SG	90,126	50,319	39,807	-	-	-	-	-	-	-
		G-DGU	SG	364,653	203,593	161,060	-	-	-	-	-	-	-
		B_Center	CN	2,523,635	-	-	-	-	-	1,644,012	-	879,623	-
		G-SG	SG	2,777,643	1,104,872	1,672,771	-	-	-	-	-	-	-
		LABOR	SO	30,989,684	12,978,184	2,239,424	12,201,020	92,300	-	2,099,174	614,181	765,401	-
				81,343,652	14,584,806	4,113,062	54,279,556	563,970	-	3,743,186	2,414,048	1,645,024	-
391	Office Furniture & Equipment												
		D_SPLIT	S	2,351,456	-	-	2,231,018	25,008	-	-	95,430	-	-
		G-DGP	SG	-	-	-	-	-	-	-	-	-	-
		G-DGU	SG	-	-	-	-	-	-	-	-	-	-
		B_Center	CN	881,065	-	-	-	-	-	573,966	-	307,099	-
		G-SG	SG	1,227,944	488,443	739,501	-	-	-	-	-	-	-
		P	SE	7,002	7,002	-	-	-	-	-	-	-	-
		LABOR	SO	21,998,162	9,212,620	1,589,665	8,660,947	65,520	-	1,490,108	435,979	543,323	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	2,238	2,238	-	-	-	-	-	-	-	-
				26,467,867	9,710,304	2,329,165	10,891,965	90,528	-	2,064,074	531,409	850,422	-
392	Transportation Equipment												
		D_SPLIT	S	30,344,593	-	-	28,790,393	322,719	-	-	1,231,480	-	-
		LABOR	SO	1,904,071	797,407	137,595	749,656	5,671	-	128,978	37,737	47,028	-
		G-SG	SG	6,641,901	2,641,970	3,999,931	-	-	-	-	-	-	-
		B_Center	CN	-	-	-	-	-	-	-	-	-	-
		G-DGU	SG	179,498	100,217	79,281	-	-	-	-	-	-	-
		P	SE	86,224	86,224	-	-	-	-	-	-	-	-
		G-DGP	SG	18,984	10,599	8,385	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	12,005	12,005	-	-	-	-	-	-	-	-
				39,187,276	3,648,422	4,225,191	29,540,049	328,391	-	128,978	1,269,217	47,028	-
393	Stores Equipment												
		D_SPLIT	S	2,998,461	-	-	2,844,885	31,889	-	-	121,687	-	-
		G-DGP	SG	-	-	-	-	-	-	-	-	-	-
		G-DGU	SG	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	66,627	27,903	4,815	26,232	198	-	4,513	1,320	1,646	-
		G-SG	SG	1,858,102	739,103	1,118,999	-	-	-	-	-	-	-
		P	SG	14,510	14,510	-	-	-	-	-	-	-	-
				4,937,700	781,516	1,123,813	2,871,117	32,088	-	4,513	123,008	1,646	-
394	Tools, Shop & Garage Equipment												
		D_SPLIT	S	10,911,877	-	-	10,352,989	116,049	-	-	442,839	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
		G-DGP	SG	6,446	3,599	2,847	-	-	-	-	-	-	-
		G-SG	SG	6,168,407	2,453,627	3,714,780	-	-	-	-	-	-	-
		LABOR	SO	494,302	207,009	35,720	194,613	1,472	-	33,483	9,797	12,209	-
		P	SE	33,106	33,106	-	-	-	-	-	-	-	-
		G-SG	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	24,172	24,172	-	-	-	-	-	-	-	-
				17,638,311	2,721,514	3,753,347	10,547,601	117,522	-	33,483	452,635	12,209	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
395	Laboratory Equipment												
		D_SPLIT	S	10,321,264	-	-	9,792,626	109,768	-	-	418,870	-	-
		G-DGP	SG	-	-	-	-	-	-	-	-	-	-
		G-DGU	SG	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	1,390,682	582,404	100,496	547,529	4,142	-	94,202	27,562	34,348	-
		P	SE	349,480	349,480	-	-	-	-	-	-	-	-
		G-SG	SG	1,995,544	793,774	1,201,770	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	3,770	3,770	-	-	-	-	-	-	-	-
				14,060,740	1,729,428	1,302,265	10,340,155	113,910	-	94,202	446,432	34,348	-
396	Power Operated Equipment												
		D_SPLIT	S	52,665,956	-	-	49,968,493	560,111	-	-	2,137,352	-	-
		G-DGP	SG	70,436	39,326	31,110	-	-	-	-	-	-	-
		G-SG	SG	12,703,138	5,052,968	7,650,170	-	-	-	-	-	-	-
		LABOR	SO	1,279,032	535,647	92,427	503,571	3,809	-	86,639	25,349	31,590	-
		G-DGU	SG	198,848	111,021	87,828	-	-	-	-	-	-	-
		P	SE	62,341	62,341	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				66,979,751	5,801,302	7,861,535	50,472,064	563,920	-	86,639	2,162,701	31,590	-
397	Communication Equipment												
		D_SPLIT	S	124,669,936	-	-	118,284,549	1,325,884	-	-	5,059,503	-	-
		G-DGP	SG	-	-	-	-	-	-	-	-	-	-
		G-DGU	SG	37,439	20,903	16,536	-	-	-	-	-	-	-
		LABOR	SO	44,276,794	18,542,699	3,199,597	17,432,319	131,874	-	2,999,215	877,517	1,093,573	-
		B_Center	CN	470,976	-	-	-	-	-	306,815	-	164,161	-
		G-SG	SG	52,646,359	20,941,312	31,705,048	-	-	-	-	-	-	-
		P	SE	42,417	42,417	-	-	-	-	-	-	-	-
		G-SG	SG	-	-	-	-	-	-	-	-	-	-
		G-SG	SG	4,472	1,779	2,693	-	-	-	-	-	-	-
				222,148,393	39,549,109	34,923,874	135,716,868	1,457,758	-	3,306,030	5,937,020	1,257,734	-
398	Misc. Equipment												
		D_SPLIT	S	1,374,243	-	-	1,303,857	14,615	-	-	55,771	-	-
		G-DGP	SG	-	-	-	-	-	-	-	-	-	-
		G-DGU	SG	-	-	-	-	-	-	-	-	-	-
		B_Center	CN	21,758	-	-	-	-	-	14,174	-	7,584	-
		LABOR	SO	431,943	180,894	31,214	170,061	1,287	-	29,259	8,561	10,668	-
		P	SE	1,045	1,045	-	-	-	-	-	-	-	-
		G-SG	SG	837,112	332,981	504,131	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				2,666,100	514,919	535,345	1,473,918	15,902	-	43,433	64,332	18,252	-
399	Coal Mine												
		P	SE	11,665,695	11,665,695	-	-	-	-	-	-	-	-
MP	Unckassified Mine Pla	P	SE	-	-	-	-	-	-	-	-	-	-
				11,665,695	11,665,695	-	-	-	-	-	-	-	-
399L	WIDCO Capital Lease												
		P	SE	-	-	-	-	-	-	-	-	-	-
	Remove Capital Leases			-	-	-	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
				-	-	-	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
1011390	General Capital Leases												
		D_SPLIT	S	691,142	-	-	655,742	7,350	-	-	28,049	-	-
		P	SG	2,166,359	2,166,359	-	-	-	-	-	-	-	-
		LABOR	SO	-	-	-	-	-	-	-	-	-	-
				2,857,500	2,166,359	-	655,742	7,350	-	-	28,049	-	-
	Remove Capital Leases			(2,857,500)	(2,166,359)	-	(655,742)	(7,350)	-	-	(28,049)	-	-
				-	-	-	-	-	-	-	-	-	-
1011346	General Gas Line Capital Leases												
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
	Remove Capital Leases			-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
GP	Unclassified Gen Plant - Acct 300												
		D_SPLIT	S	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	17,939,437	7,512,865	1,296,367	7,062,977	53,431	-	1,215,179	355,540	443,078	-
		B_Center	CN	-	-	-	-	-	-	-	-	-	-
		G-SG	SG	-	-	-	-	-	-	-	-	-	-
		G-DGP	SG	-	-	-	-	-	-	-	-	-	-
		G-DGU	SG	-	-	-	-	-	-	-	-	-	-
				17,939,437	7,512,865	1,296,367	7,062,977	53,431	-	1,215,179	355,540	443,078	-
399G	Unclassified Gen Plant - Acct 300												
		D_SPLIT	S	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	-	-	-	-	-	-	-	-	-	-
		G-SG	SG	-	-	-	-	-	-	-	-	-	-
		G-DGP	SG	-	-	-	-	-	-	-	-	-	-
		G-DGU	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
TOTAL GENERAL PLANT				**513,585,933**	**99,094,295**	**61,615,055**	**319,821,430**	**3,408,687**	**-**	**11,086,856**	**14,045,943**	**4,513,667**	**-**
301	Organization												
		D_SPLIT	S	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	-	-	-	-	-	-	-	-	-	-
		I-SG	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
302	Franchise & Consent												
		D_SPLIT	S	-	-	-	-	-	-	-	-	-	-
		I-SG	SG	4,368,333	2,777,371	1,590,962	-	-	-	-	-	-	-
		I-DGP	SG	27,790,447	27,790,447	-	-	-	-	-	-	-	-
		I-DGU	SG	2,622,724	2,622,724	-	-	-	-	-	-	-	-
		I-DGP	SG	-	-	-	-	-	-	-	-	-	-
		I-DGU	SG	128,398	128,398	-	-	-	-	-	-	-	-
				34,909,902	33,318,940	1,590,962	-	-	-	-	-	-	-
303	Miscellaneous Intangible Plant												
		D_SPLIT	S	4,606,407	-	-	4,370,474	48,990	-	-	186,943	-	-
		LABOR	SG	52,366,046	21,930,400	3,784,155	20,617,157	155,967	-	3,547,163	1,037,837	1,293,366	-
		LABOR	SO	191,155,091	80,053,928	13,813,541	75,260,113	569,338	-	12,948,434	3,788,482	4,721,255	-
		P	SE	1,241	1,241	-	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
		CSS_SYS	CN	70,461,152	-	-	-	-	-	31,237,777	16,440,935	22,782,439	-
		I-DGP	SG	-	-	-	-	-	-	-	-	-	-
		I-DGP	SG	-	-	-	-	-	-	-	-	-	-
				318,589,936	101,985,569	17,597,696	100,247,744	774,295	-	47,733,375	21,454,197	28,797,060	-
303	Less Non-Utility Plant												
		I-SITUS	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
IP	Unclassified Intangible Plant - Acct 300												
		D_SPLIT	S	-	-	-	-	-	-	-	-	-	-
		I-SG	SG	-	-	-	-	-	-	-	-	-	-
		I-DGU	SG	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
TOTAL INTANGIBLE PLANT				**353,499,838**	**135,304,509**	**19,188,658**	**100,247,744**	**774,295**	**-**	**47,733,375**	**21,454,197**	**28,797,060**	**-**

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
TOTAL ELECTRIC PLANT IN SERVICE				**10,425,808,241**	**4,108,230,762**	**3,060,325,174**	**2,986,873,710**	**32,954,998**	**-**	**58,820,231**	**145,292,638**	**33,310,728**	**-**
105	Plant Held For Future Use												
		D_SPLIT	S	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		T	SG	408,094	-	408,094	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
		G	SG	(408,094)	(79,561)	(143,540)	(175,384)	-	-	(4,456)	(5,152)	-	-
				-	(79,561)	264,553	(175,384)	-	-	(4,456)	(5,152)	-	-
114	Electric Plant Acquisition Adjustments												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SG	38,902,639	38,902,639	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				38,902,639	38,902,639	-	-	-	-	-	-	-	-
115	Accum Provision for Asset Acquisition Adjustments												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SG	(38,199,390)	(38,199,390)	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				(38,199,390)	(38,199,390)	-	-	-	-	-	-	-	-
128	Pensions												
		LABOR	SO	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
124	Weatherization												
		DSM	S	-	-	-	-	-	-	-	-	-	-
		DSM	SO	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
182W	Weatherization												
		DSM	S	-	-	-	-	-	-	-	-	-	-
		DSM	SG	-	-	-	-	-	-	-	-	-	-
		DSM	SG	-	-	-	-	-	-	-	-	-	-
		DSM	SO	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
186W	Weatherization												
		DSM	S	-	-	-	-	-	-	-	-	-	-
		DSM	CN	-	-	-	-	-	-	-	-	-	-
		DSM	CNP	-	-	-	-	-	-	-	-	-	-
		DSM	SG	-	-	-	-	-	-	-	-	-	-
		DSM	SO	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
	Total Weatherization			-	-	-	-	-	-	-	-	-	-
151	Fuel Stock												
		P	DEU	-	-	-	-	-	-	-	-	-	-
		P	SE	38,308,735	38,308,735	-	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
		P	SE	-	-	-	-	-	-	-	-	-	-
		P	SE	-	-	-	-	-	-	-	-	-	-
				38,308,735	38,308,735	-	-	-	-	-	-	-	-
152	Fuel Stock - Undistributed												
		P	SE	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
25316	DG&T Working Capital Deposit												
		P	SE	63,275	63,275	-	-	-	-	-	-	-	-
				63,275	63,275	-	-	-	-	-	-	-	-
25317	DG&T Working Capital Deposit												
		P	SE	(1,103,462)	(1,103,462)	-	-	-	-	-	-	-	-
				(1,103,462)	(1,103,462)	-	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
25319	Provo Working Capital Deposit												
		P	SE	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
	Total Fuel Stock			37,268,548	37,268,548	-	-	-	-	-	-	-	-
154	Materials and Supplies												
		MSS	S	92,111,560	67,557,192	1,374,249	22,536,931	-	-	-	643,188	-	-
		MSS	SG	(34,091)	(25,003)	(509)	(8,341)	-	-	-	(238)	-	-
		MSS	SE	-	-	-	-	-	-	-	-	-	-
		MSS	SO	(226,098)	(165,827)	(3,373)	(55,319)	-	-	-	(1,579)	-	-
		MSS	SG	36,041,827	26,434,083	537,722	8,818,352	-	-	-	251,670	-	-
		MSS	SG	9,124	6,692	136	2,232	-	-	-	64	-	-
		MSS	SNPD	(329,812)	(241,893)	(4,921)	(80,695)	-	-	-	(2,303)	-	-
		MSS	SG	-	-	-	-	-	-	-	-	-	-
		MSS	SG	-	-	-	-	-	-	-	-	-	-
		MSS	SG	-	-	-	-	-	-	-	-	-	-
		MSS	SG	-	-	-	-	-	-	-	-	-	-
		MSS	SG	2,322,954	1,703,720	34,657	568,357	-	-	-	16,221	-	-
		MSS	SG	-	-	-	-	-	-	-	-	-	-
				129,895,465	95,268,964	1,937,962	31,781,517	-	-	-	907,022	-	-
158	WA GHG Allocation Inventory												
		MSS	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
25318	Provo Working Capital Deposit												
		MSS	SG	(73,394)	(53,829)	(1,095)	(17,957)	-	-	-	(512)	-	-
				(73,394)	(53,829)	(1,095)	(17,957)	-	-	-	(512)	-	-
	Total Materials & Supplies			129,822,071	95,215,135	1,936,867	31,763,560	-	-	-	906,510	-	-
165	Prepayments												
		LABOR	S	4,549,813	1,905,418	328,785	1,791,317	13,551	-	308,195	90,172	112,374	-
		GP	GPS	54,209	21,361	15,912	15,530	171	-	306	755	173	-
		PT	SG	1,649,178	920,830	728,348	-	-	-	-	-	-	-
		P	SE	154,795	154,795	-	-	-	-	-	-	-	-
		LABOR	SO	10,430,189	4,368,064	753,722	4,106,494	31,065	-	706,519	206,715	257,611	-
				16,838,184	7,370,468	1,826,768	5,913,341	44,788	-	1,015,019	297,642	370,158	-
182M	Misc Regulatory Assets												
		DDS2	S	75,123	87,365	(1,726)	(10,027)	(13)	-	(287)	(84)	(105)	-
		DEFSG	SG	-	-	-	-	-	-	-	-	-	-
		P	SGCT	-	-	-	-	-	-	-	-	-	-
		DEFSG	SG	-	-	-	-	-	-	-	-	-	-
		P	SE	33,785,672	33,785,672	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	23,420,768	9,808,394	1,692,467	9,221,045	69,757	-	1,586,472	464,174	578,459	-
				57,281,563	43,681,431	1,690,741	9,211,018	69,744	-	1,586,185	464,089	578,354	-
186M	Misc Deferred Debits												

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
		LABOR	S	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		DEFSG	SG	44,579,610	41,559,303	3,020,307	-	-	-	-	-	-	-
		LABOR	SO	-	-	-	-	-	-	-	-	-	-
		P	SE	80,732	80,732	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		GP	EXCTAX	-	-	-	-	-	-	-	-	-	-
				44,660,342	41,640,035	3,020,307	-	-	-	-	-	-	-
Working Capital													
CWC	Cash Working Capital												
		CWC	S	36,025,180	24,677,978	3,066,513	7,267,027	49,744	-	492,869	258,123	212,927	-
		CWC	SO	-	-	-	-	-	-	-	-	-	-
		CWC	SE	-	-	-	-	-	-	-	-	-	-
				36,025,180	24,677,978	3,066,513	7,267,027	49,744	-	492,869	258,123	212,927	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
OWC	Other Work. Cap.												
131	Cash	GP	SNP	-	-	-	-	-	-	-	-	-	-
135	Working Funds	GP	SG	-	-	-	-	-	-	-	-	-	-
141	Notes Receivable	GP	SO	-	-	-	-	-	-	-	-	-	-
143	Other A/R	LABOR	SO	18,532,802	7,761,361	1,339,246	7,296,592	55,198	-	1,255,372	367,300	457,734	-
232	A/P	LABOR	S	-	-	-	-	-	-	-	-	-	-
232	A/P	LABOR	SO	(1,772,159)	(742,163)	(128,062)	(697,721)	(5,278)	-	(120,042)	(35,122)	(43,770)	-
232	A/P	P	SE	(741,683)	(741,683)	-	-	-	-	-	-	-	-
232	A/P	P	SG	(1,242,552)	(1,242,552)	-	-	-	-	-	-	-	-
2533	Other Msc. Df. Crd.	P	S	-	-	-	-	-	-	-	-	-	-
2533	Other Msc. Df. Crd.	P	SE	(2,932,940)	(2,932,940)	-	-	-	-	-	-	-	-
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	-	-	-	-	-	-	-	-	-	-
				11,843,468	2,102,022	1,211,183	6,598,872	49,920	-	1,135,330	332,177	413,964	-
Total Working Capital				47,868,648	26,780,000	4,277,696	13,865,898	99,664	-	1,628,199	590,300	626,890	-
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				**334,442,604**	**252,579,303**	**13,016,932**	**60,578,434**	**214,196**	**-**	**4,224,947**	**2,253,389**	**1,575,402**	**-**
235	Customer Service Deposits												
		C_BILLING	S	-	-	-	-	-	-	-	-	-	-
		C_BILLING	CN	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
2281	Prov for Property Insur	LABOR	S	31,639,210	13,250,199	2,286,361	12,456,746	94,234	-	2,143,172	627,054	781,443	-
2282	Prov for Injuries & Dar	LABOR	SO	-	-	-	-	-	-	-	-	-	-
2282	Prov for Injuries & Dar	LABOR	S	5,479,612	2,294,809	395,976	2,157,391	16,321	-	371,177	108,600	135,339	-
2283	Prov for Pensions and I	LABOR	SO	(343,535)	(143,869)	(24,825)	(135,254)	(1,023)	-	(23,270)	(6,808)	(8,485)	-
2283	Prov for Pensions and I	LABOR	S	-	-	-	-	-	-	-	-	-	-
25335	Pens Oblig	LABOR	SE	(30,321,356)	(12,698,295)	(2,191,128)	(11,937,891)	(90,309)	-	(2,053,903)	(600,936)	(748,894)	-
254	Reg Liabilities - Insura	LABOR	SO	(9,278,417)	(3,885,713)	(670,491)	(3,653,027)	(27,635)	-	(628,500)	(183,888)	(229,164)	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
				(2,824,487)	(1,182,868)	(204,107)	(1,112,035)	(8,412)	-	(191,325)	(55,978)	(69,761)	-
22841	Accum Misc Oper Provisions - Other												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SG	(63,148)	(63,148)	-	-	-	-	-	-	-	-
				(63,148)	(63,148)	-	-	-	-	-	-	-	-
254105	ARO	P	S	-	-	-	-	-	-	-	-	-	-
230	ARO	P	TROJD	(1,860,674)	(1,860,674)	-	-	-	-	-	-	-	-
254105	ARO	P	TROJD	-	-	-	-	-	-	-	-	-	-
254		P	S	(338,613,472)	(338,613,472)	-	-	-	-	-	-	-	-
				(340,474,146)	(340,474,146)	-	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
252	Customer Advances for Construction												
		D_SPLIT	S	(5,177,396)	-	-	(4,912,218)	(55,062)	-	-	(210,115)	-	-
		T	SE	-	-	-	-	-	-	-	-	-	-
		T	SG	(41,481,126)	-	(41,481,126)	-	-	-	-	-	-	-
		D_SPLIT	SO	-	-	-	-	-	-	-	-	-	-
		B_Center	CN	-	-	-	-	-	-	-	-	-	-
				(46,658,522)	-	(41,481,126)	(4,912,218)	(55,062)	-	-	(210,115)	-	-
25398	SO2 Emissions												
		P	SE	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
25399	Other Deferred Credits												
		D_SPLIT	S	(331,064)	-	-	(314,108)	(3,521)	-	-	(13,436)	-	-
		LABOR	SO	(3,339,904)	(1,398,720)	(241,353)	(1,314,961)	(9,948)	-	(226,238)	(66,193)	(82,491)	-
		P	SG	(81,921,571)	(81,921,571)	-	-	-	-	-	-	-	-
		P	SE	(4,157,179)	(4,157,179)	-	-	-	-	-	-	-	-
				(89,749,718)	(87,477,470)	(241,353)	(1,629,069)	(13,469)	-	(226,238)	(79,629)	(82,491)	-
190	Accumulated Deferred Income Taxes												
		D_SPLIT	S	80,908,155	-	-	76,764,174	860,471	-	-	3,283,511	-	-
		CSS_SYS	CN	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	12,786,344	5,354,799	923,986	5,034,141	38,083	-	866,119	253,411	315,804	-
		P	GPS	-	-	-	-	-	-	-	-	-	-
		IBT	IBT	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		C_BILLING	BADDEBT	2,482,069	-	-	-	-	-	2,482,069	-	-	-
		P	TROJD	308,510	308,510	-	-	-	-	-	-	-	-
		P	SG	432,428	432,428	-	-	-	-	-	-	-	-
		P	SE	1,118,875	1,118,875	-	-	-	-	-	-	-	-
		LABOR	SNP	-	-	-	-	-	-	-	-	-	-
		D_SPLIT	SNPD	577,021	-	-	547,467	6,137	-	-	23,417	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				98,613,403	7,214,612	923,986	82,345,782	904,690	-	3,348,189	3,560,339	315,804	-
281	Accumulated Deferred Income Taxes												
		P	S	-	-	-	-	-	-	-	-	-	-
		PT	SG	(0)	(0)	(0)	-	-	-	-	-	-	-
		T	SG	-	-	-	-	-	-	-	-	-	-
				(0)	(0)	(0)	-	-	-	-	-	-	-
282	Accumulated Deferred Income Taxes												
		GP	S	(67,722,863)	(26,685,811)	(19,878,937)	(19,401,818)	(214,066)	-	(382,078)	(943,777)	(216,376)	-
		CSS_SYS	CN	(6,702)	-	-	-	-	-	(2,971)	(1,564)	(2,167)	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		ACCMDIT	DITBAL	(95,790)	(43,917)	(28,179)	(23,568)	-	-	(58)	(67)	-	-
		PT	SNPD	-	-	-	-	-	-	-	-	-	-
		PT	CIAC	-	-	-	-	-	-	-	-	-	-
		C_Service	SNP	(65,144)	-	-	-	-	-	-	-	(65,144)	-
		P	SG-U	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	(45,915,370)	(19,228,919)	(3,318,007)	(18,077,446)	(136,755)	-	(3,110,208)	(909,992)	(1,134,043)	-
		P	SG	-	-	-	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
		P	SE	(327,393)	(327,393)	-	-	-	-	-	-	-	-
		P	SG	(667,471,869)	(667,471,869)	-	-	-	-	-	-	-	-
				(781,605,130)	(713,757,908)	(23,225,123)	(37,502,833)	(350,820)	-	(3,495,316)	(1,855,399)	(1,417,731)	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
283	Accumulated Deferred Income Taxes												
		GP	S	(8,897,652)	(3,506,069)	(2,611,760)	(2,549,074)	(28,125)	-	(50,199)	(123,996)	(28,428)	-
		P	SG	(413,127)	(413,127)	-	-	-	-	-	-	-	-
		P	SE	(161,499)	(161,499)	-	-	-	-	-	-	-	-
		LABOR	SO	(8,448,561)	(3,538,177)	(610,523)	(3,326,303)	(25,163)	-	(572,287)	(167,441)	(208,667)	-
		GP	GPS	(2,517,329)	(991,939)	(738,921)	(721,186)	(7,957)	-	(14,202)	(35,081)	(8,043)	-
		LABOR	SNP	(138,531)	(58,015)	(10,011)	(54,541)	(413)	-	(9,384)	(2,746)	(3,422)	-
		P	TROJD	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SGCT	-	-	-	-	-	-	-	-	-	-
		IBT	IBT	-	-	-	-	-	-	-	-	-	-
				(20,576,699)	(8,668,827)	(3,971,214)	(6,651,104)	(61,658)	-	(646,072)	(329,264)	(248,560)	-
TOTAL ACCUMULATED DEF INCOME TAX				(703,568,427)	(715,212,123)	(26,272,350)	38,191,845	492,213	-	(793,199)	1,375,676	(1,350,487)	-
255	Accumulated Investment Tax Credit												
		LABOR	S	-	-	-	-	-	-	-	-	-	-
		LABOR	ITC84	-	-	-	-	-	-	-	-	-	-
		LABOR	ITC85	-	-	-	-	-	-	-	-	-	-
		LABOR	ITC86	-	-	-	-	-	-	-	-	-	-
		LABOR	ITC88	-	-	-	-	-	-	-	-	-	-
		LABOR	ITC89	-	-	-	-	-	-	-	-	-	-
		LABOR	ITC90	-	-	-	-	-	-	-	-	-	-
		LABOR	SG	(40,918)	(17,136)	(2,957)	(16,110)	(122)	-	(2,772)	(811)	(1,011)	-
				(40,918)	(17,136)	(2,957)	(16,110)	(122)	-	(2,772)	(811)	(1,011)	-
TOTAL RATE BASE DEDUCTIONS				**(1,183,379,365)**	**(1,144,426,891)**	**(68,201,894)**	**30,522,412**	**415,147**	**-**	**(1,213,534)**	**1,029,143**	**(1,503,749)**	**-**
108SP	Steam Prod Plant Accumulated Depr												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SG	(221,760,155)	(221,760,155)	-	-	-	-	-	-	-	-
		P	SG	(206,798,180)	(206,798,180)	-	-	-	-	-	-	-	-
		P	SG	(1,074,640,597)	(1,074,640,597)	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				(1,503,198,932)	(1,503,198,932)	-	-	-	-	-	-	-	-
108NP	Nuclear Prod Plant Accumulated Depr												
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
108HP	Hydraulic Prod Plant Accum Depr												
		P	S	-	-	-	-	-	-	-	-	-	-
		P	SG	(39,230,371)	(39,230,371)	-	-	-	-	-	-	-	-
		P	SG	(8,751,803)	(8,751,803)	-	-	-	-	-	-	-	-
		P	SG	(59,903,905)	(59,903,905)	-	-	-	-	-	-	-	-
		P	SG	(23,614,451)	(23,614,451)	-	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
		P	SG	(1,779,628)	(1,779,628)	-	-	-	-	-	-	-	-
				(133,280,158)	(133,280,158)	-	-	-	-	-	-	-	-
108OP	Other Production Plant - Accum Depr												
		P	S	(173,154,068)	(173,154,068)	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	(24,587,538)	(24,587,538)	-	-	-	-	-	-	-	-
		P	SG	(172,503,291)	(172,503,291)	-	-	-	-	-	-	-	-
		P	SG	(13,478,790)	(13,478,790)	-	-	-	-	-	-	-	-
				(383,723,687)	(383,723,687)	-	-	-	-	-	-	-	-
108EP	Experimental Plant - Accum Depr												
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
TOTAL PRODUCTION PLANT DEPRECIATION				**(2,020,202,776)**	**(2,020,202,776)**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
108TP	Transmission Plant Accumulated Depr												
		T_Split	S	-	-	-	-	-	-	-	-	-	-
		T_Split	SG	(93,970,067)	(1,465,854)	(92,504,214)	-	-	-	-	-	-	-
		T_Split	SG	(113,175,930)	(1,765,449)	(111,410,482)	-	-	-	-	-	-	-
		T_Split	SG	(444,839,407)	(6,939,119)	(437,900,287)	-	-	-	-	-	-	-
TOTAL TRANS PLANT ACCUM DEPR				**(651,985,404)**	**(10,170,422)**	**(641,814,983)**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
108360	Land and Land Rights												
		D	S	(2,858,488)	-	-	(2,858,488)	-	-	-	-	-	-
				(2,858,488)	-	-	(2,858,488)	-	-	-	-	-	-
108361	Structures and Improvements												
		D	S	(10,548,995)	-	-	(10,548,995)	-	-	-	-	-	-
				(10,548,995)	-	-	(10,548,995)	-	-	-	-	-	-
108362	Station Equipment												
		D	S	(112,577,498)	-	-	(112,577,498)	-	-	-	-	-	-
				(112,577,498)	-	-	(112,577,498)	-	-	-	-	-	-
108363	Storage Battery Equipment												
		D	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
108364	Poles, Towers & Fixtures												
		D	S	(276,584,933)	-	-	(276,584,933)	-	-	-	-	-	-
				(276,584,933)	-	-	(276,584,933)	-	-	-	-	-	-
108365	Overhead Conductors												
		D	S	(147,706,066)	-	-	(147,706,066)	-	-	-	-	-	-
				(147,706,066)	-	-	(147,706,066)	-	-	-	-	-	-
108366	Underground Conduit												
		D	S	(53,984,823)	-	-	(53,984,823)	-	-	-	-	-	-
				(53,984,823)	-	-	(53,984,823)	-	-	-	-	-	-
108367	Underground Conductors												

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
		D	S	(107,614,232)	-	-	(107,614,232)	-	-	-	-	-	-
				(107,614,232)	-	-	(107,614,232)	-	-	-	-	-	-
108368	Line Transformers												
		D	S	(270,462,078)	-	-	(270,462,078)	-	-	-	-	-	-
				(270,462,078)	-	-	(270,462,078)	-	-	-	-	-	-
108369	Services												
		D	S	(161,639,339)	-	-	(161,639,339)	-	-	-	-	-	-
				(161,639,339)	-	-	(161,639,339)	-	-	-	-	-	-
108370	Meters												
		C_Meter	S	(34,040,310)	-	-	-	-	-	-	(34,040,310)	-	-
				(34,040,310)	-	-	-	-	-	-	(34,040,310)	-	-
108371	Installations on Customers' Premises												
		DL	S	(2,164,552)	-	-	-	(2,164,552)	-	-	-	-	-
				(2,164,552)	-	-	-	(2,164,552)	-	-	-	-	-
108372	Leased Property												
		D	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
108373	Street Lights												
		DL	S	(12,616,113)	-	-	-	(12,616,113)	-	-	-	-	-
				(12,616,113)	-	-	-	(12,616,113)	-	-	-	-	-
108D00	Unclassified Dist Plant - Acct 300												
		D_SPLIT	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
108DS	Unclassified Dist Sub Plant - Acct 300												
		D_SPLIT	S	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
108DP	Unclassified Dist Sub Plant - Acct 300												
		D_SPLIT	S	685,999	-	-	650,863	7,296	-	-	27,840	-	-
				685,999	-	-	650,863	7,296	-	-	27,840	-	-
TOTAL DISTRIBUTION PLANT DEPR				**(1,192,111,426)**	**-**	**-**	**(1,143,325,587)**	**(14,773,369)**	**-**	**-**	**(34,012,470)**	**-**	**-**
108GP	General Plant Accumulated Depr												
		D_SPLIT	S	(96,741,359)	-	-	(91,786,427)	(1,028,859)	-	-	(3,926,073)	-	-
		G-DGP	SG	(127,180)	(71,007)	(56,173)	-	-	-	-	-	-	-
		G-DGU	SG	(562,467)	(314,036)	(248,431)	-	-	-	-	-	-	-
		G-SG	SG	(41,918,891)	(16,674,212)	(25,244,679)	-	-	-	-	-	-	-
		B_Center	CN	(1,684,429)	-	-	-	-	-	(1,097,314)	-	(587,115)	-
		LABOR	SO	(37,251,967)	(15,600,768)	(2,691,958)	(14,666,558)	(110,952)	-	(2,523,368)	(738,293)	(920,070)	-
		P	SE	(503,748)	(503,748)	-	-	-	-	-	-	-	-
		G-SG	SG	(40,155)	(15,973)	(24,182)	-	-	-	-	-	-	-
		G-SG	SG	-	-	-	-	-	-	-	-	-	-
				(178,830,195)	(33,179,743)	(28,265,424)	(106,452,985)	(1,139,811)	-	(3,620,682)	(4,664,365)	(1,507,185)	-
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				**(178,830,195)**	**(33,179,743)**	**(28,265,424)**	**(106,452,985)**	**(1,139,811)**	**-**	**(3,620,682)**	**(4,664,365)**	**(1,507,185)**	**-**
TOTAL ACCUM DEPR - PLANT IN SERVICE				**(4,043,129,802)**	**(2,063,552,941)**	**(670,080,406)**	**(1,249,778,572)**	**(15,913,180)**	**-**	**(3,620,682)**	**(38,676,835)**	**(1,507,185)**	**-**

FERC ACCT	DESCRIPTION	BUSINESS FUNCTION	JAM FACTOR	Total $	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM
111OP	Accum Prov for Amort-Steam												
		P	S	(198,109)	(198,109)	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				(198,109)	(198,109)	-	-	-	-	-	-	-	-
111GP	Accum Prov for Amort-General												
		D_SPLIT	S	(5,273,651)	-	-	(5,003,544)	(56,086)	-	-	(214,022)	-	-
		CSS_SYS	CN	-	-	-	-	-	-	-	-	-	-
		I-SG	SG	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	(412,712)	(172,840)	(29,824)	(162,490)	(1,229)	-	(27,956)	(8,179)	(10,193)	-
		P	SE	-	-	-	-	-	-	-	-	-	-
				(5,686,363)	(172,840)	(29,824)	(5,166,033)	(57,315)	-	(27,956)	(222,201)	(10,193)	-
111HP	Accum Prov for Amort-Hydro												
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	(1,138,696)	(1,138,696)	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
				(1,138,696)	(1,138,696)	-	-	-	-	-	-	-	-
111IP	Accum Prov for Amort-Intangible Plant												
		I-SITUS	S	(159,409)	-	(103,996)	(53,831)	-	-	-	(1,581)	-	-
		I-DGP	SG	-	-	-	-	-	-	-	-	-	-
		I-DGU	SG	(113,451)	(113,451)	-	-	-	-	-	-	-	-
		P	SE	(770)	(770)	-	-	-	-	-	-	-	-
		I-SG	SG	(31,378,917)	(19,950,608)	(11,428,309)	-	-	-	-	-	-	-
		I-SG	SG	(13,378,910)	(8,506,265)	(4,872,645)	-	-	-	-	-	-	-
		I-SG	SG	(1,777,279)	(1,129,988)	(647,291)	-	-	-	-	-	-	-
		CUST	CN	(63,528,158)	-	-	-	-	-	(28,164,150)	(14,823,237)	(20,540,771)	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		PTD	SO	(115,498,543)	(46,237,218)	(36,572,209)	(32,689,116)	-	-	-	-	-	-
				(225,835,437)	(75,938,301)	(53,624,451)	(32,742,946)	-	-	(28,164,150)	(14,824,818)	(20,540,771)	-
111IP	Less Non-Utility Plant												
		NUTIL	OTH	-	-	-	-	-	-	-	-	-	-
				(225,835,437)	(75,938,301)	(53,624,451)	(32,742,946)	-	-	(28,164,150)	(14,824,818)	(20,540,771)	-
111390	Accum Amtr - Capital Lease												
		LABOR	S	-	-	-	-	-	-	-	-	-	-
		P	SG	-	-	-	-	-	-	-	-	-	-
		LABOR	SO	-	-	-	-	-	-	-	-	-	-
				-	-	-	-	-	-	-	-	-	-
	Remove Capital Lease Amtr			-	-	-	-	-	-	-	-	-	-
TOTAL ACCUM PROV FOR AMORTIZATION				**(232,858,605)**	**(77,447,946)**	**(53,654,275)**	**(37,908,980)**	**(57,315)**	**-**	**(28,192,106)**	**(15,047,019)**	**(20,550,964)**	**-**

Docket No. UE 433
Exhibit PAC/1904
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Functional Factors

February 2024

Functional Factors

Function	Description	Production	Transmission	Distribution	Dist-Lighting	Ancillary	C_Billing	C_Metering	C_Service	DSM	Total
	Internal Factors										
CWC	Cash Working Capital	68.5020%	8.5121%	20.1721%	0.1381%	0.0000%	1.3681%	0.7165%	0.5910%	0.0000%	100%
D_SPLIT	Distribution Split between Functions	0.0000%	0.0000%	94.8782%	1.0635%	0.0000%	0.0000%	4.0583%	0.0000%	0.0000%	100%
GP	Gross Plant	39.4044%	29.3534%	28.6488%	0.3161%	0.0000%	0.5642%	1.3936%	0.3195%	0.0000%	100%
IBT	Income Before Taxes	-57.7620%	57.9125%	92.9262%	1.9070%	0.0000%	0.2698%	5.4248%	-0.6784%	0.0000%	100%
NP	Net Plant	31.9884%	37.9945%	27.6299%	0.2762%	0.0000%	0.4392%	1.4890%	0.1830%	0.0000%	100%
PT	Production / Transmission	55.8357%	44.1643%								100%
PTD	Prod, Trans, Dist Plant	40.0327%	31.6646%	28.3026%							100%
REVREQ	Revenue Requirement	57.4929%	16.8768%	22.7488%	0.1738%	0.0000%	1.2050%	0.9469%	0.5558%	0.0000%	100%
T_SPLIT	Transmission Split	1.5599%	98.4401%								100%
TD	Transmission / Distribution		52.8032%	47.1968%							100%
	External Factors										
ACCMDIT	Deferred Income Tax - Balance	45.8475%	29.4179%	24.6038%	0.0000%	0.0000%	0.0607%	0.0701%	0.0000%	0.0000%	100%
ANC	Ancillary Function	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100%
B_CENTER	Business Centers	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	65.1446%	0.0000%	34.8554%	0.0000%	100%
BOOKDEPR	Book Depreciation	60.9173%	15.4894%	22.5693%	0.2731%	0.0000%	0.0878%	0.6630%	0.0000%	0.0000%	100%
C_BILLING	Customer Billing	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	100%
C_METER	Customer Metering	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	100%
C_SERVICE	Customer Other	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	100%
CSS_SYS	CSS System	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	44.3333%	23.3333%	32.3333%	0.0000%	100%
CUST	Customer	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	44.3333%	23.3333%	32.3333%	0.0000%	100%
CUST901	Supervision	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	59.0822%	37.4112%	3.5066%	0.0000%	100%
CUST903	Cust. Records & Coll. Exp.	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	76.0086%	4.1993%	19.7921%	0.0000%	100%
CUST905	Misc. Customer Acct. Exp.	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	62.6614%	37.3386%	0.0000%	100%
D	Distribution Only	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100%
DL	Distribution Only-LGT	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100%
DDS2	Deferred Debits - Situs	116.2955%	-2.2975%	-13.3470%	-0.0168%	0.0000%	-0.3826%	-0.1120%	-0.1395%	0.0000%	100%
DDS6	Deferred Debits - Situs	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0%
DDSO2	Deferred Debits - System Overhead	39.5923%	7.5555%	43.1967%	0.2496%	0.0000%	5.6758%	1.6606%	2.0695%	0.0000%	100%
DDSO6	Deferred Debits - System Overhead	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0%
DEFSG	Deferred Debit - System Generation	93.2249%	6.7751%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100%
DSM	Demand Side Management	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100%
DPW	Distribution Poles & Wires	0.0000%	0.0000%	97.1461%	0.0000%	0.0000%	0.0000%	2.8539%	0.0000%	0.0000%	100%
ESD	Environmental Services Department	30.0000%	10.0000%	60.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100%
FERC	FERC Fees	48.9234%	51.0766%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100%
G	General Plant	19.4958%	35.1734%	42.9764%	0.0000%	0.0000%	1.0919%	1.2625%	0.0000%	0.0000%	100%
G-DGP	General Plant - DGP Factor	55.8319%	44.1681%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100%
G-DGU	General Plant - DGU Factor	55.8319%	44.1681%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100%
G-SG	General Plant - SG Factor	39.7773%	60.2227%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100%
G-SITUS	General Plant - SITUS Factor	0.0000%	28.5980%	69.3642%	0.0000%	0.0000%	0.0000%	2.0378%	0.0000%	0.0000%	100%
I	Intangible Plant	39.6408%	20.0496%	15.6606%	0.0000%	0.0000%	7.9092%	10.3921%	6.3476%	0.0000%	100%
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%
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%
I-SG	Intangible Plant - SG Factor	63.5797%	36.4203%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100%
I-SITUS	Intangible Plant - SITUS Factor	0.0000%	65.2389%	33.7690%	0.0000%	0.0000%	0.0000%	0.9921%	0.0000%	0.0000%	100%
LABOR	Direct Labor Expense	41.8790%	7.2264%	39.3712%	0.2978%	0.0000%	6.7738%	1.9819%	2.4699%	0.0000%	100%
MSS	Materials & Supplies	73.3428%	1.4919%	24.4670%	0.0000%	0.0000%	0.0000%	0.6983%	0.0000%	0.0000%	100%
NONE	Not Functionalized	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0%
NUTIL	Non-Utility	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0%
OTHDGP	Other Revenues - DGP Factor	15.1810%	84.8151%	0.0039%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100%
OTHDGU	Other Revenues - DGU Factor	15.1810%	84.8151%	0.0039%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100%
OTHSE	Other Revenues - SE Factor	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100%
OTHSG	Other Revenues - SG Factor	15.1810%	84.8151%	0.0039%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100%
OTHSGR	Other Revenues - Rolled-In SG Factor	15.1810%	84.8151%	0.0039%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100%
OTHSITUS	Other Revenues - SITUS	3.6445%	87.7238%	8.6317%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100%
OTHSO	Other Revenues - SO Factor	0.0000%	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100%
P	Production	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100%
SCHMA	Schedule M Additions	32.1161%	26.0678%	39.5366%	0.0034%	0.0000%	0.7803%	1.2944%	0.2014%	0.0000%	100%
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%
SCHMAP	Schedule M Additions - Permanent	61.8426%	4.7442%	25.8479%	0.1955%	0.0000%	4.4471%	1.3011%	1.6215%	0.0000%	100%
SCHMAP-SO	Schedule M Additions - Permanent-SO	62.9639%	4.6048%	25.0883%	0.1898%	0.0000%	4.3164%	1.2629%	1.5739%	0.0000%	100%
SCHMAT	Schedule M Additions - Temporary	32.0433%	26.1201%	39.5701%	0.0029%	0.0000%	0.7713%	1.2944%	0.1979%	0.0000%	100%
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%
SCHMAT-SE	Schedule M Additions - Temporary-SE	102.5711%	-0.3197%	-1.7417%	-0.0132%	0.0000%	-0.2997%	-0.0877%	-0.1093%	0.0000%	100%
SCHMAT-SITUS	Schedule M Additions - Temporary-SITUS	59.2308%	13.0570%	23.5454%	0.0992%	0.0000%	2.2553%	0.9900%	0.8223%	0.0000%	100%
SCHMAT-SNP	Schedule M Additions - Temporary-SNP	44.6690%	26.6945%	27.8168%	0.0000%	0.0000%	0.0012%	0.8178%	0.0008%	0.0000%	100%
SCHMAT-SO	Schedule M Additions - Temporary-SO	41.8593%	7.0888%	39.4529%	0.2999%	0.0000%	6.8216%	1.9901%	2.4873%	0.0000%	100%
SCHMD	Schedule M Deductions	60.7520%	24.4791%	16.0175%	-0.0531%	0.0000%	-1.1623%	0.2161%	-0.2494%	0.0000%	100%
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%
SCHMDP	Schedule M Deductions - Permanent	98.2709%	0.8343%	0.8693%	0.0000%	0.0000%	0.0000%	0.0255%	0.0000%	0.0000%	100%
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%
SCHMDT	Schedule M Deductions - Temporary	60.6749%	24.5277%	16.0486%	-0.0532%	0.0000%	-1.1647%	0.2165%	-0.2499%	0.0000%	100%
SCHMDT-GPS	Schedule M Deductions - Temporary-GPS	44.6744%	26.6934%	27.8150%	0.0000%	0.0000%	0.0000%	0.8171%	0.0000%	0.0000%	100%
SCHMDT-SG	Schedule M Deductions - Temporary-SG	102.7238%	-2.7238%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100%
SCHMDT-SITUS	Schedule M Deductions - Temporary-SITUS	104.4057%	-0.9268%	-3.3169%	-0.0036%	0.0000%	-0.0862%	-0.0394%	-0.0327%	0.0000%	100%
SCHMDT-SNP	Schedule M Deductions - Temporary-SNP	44.6744%	26.6934%	27.8150%	0.0000%	0.0000%	0.0000%	0.8171%	0.0000%	0.0000%	100%
SCHMDT-SO	Schedule M Deductions - Temporary-SO	41.9875%	-1.7174%	42.2164%	0.4626%	0.0000%	10.5108%	2.7108%	3.8294%	0.0000%	100%
STEP_UP	Step-up Transformers	6.4452%	93.5548%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100%
T	Transmission	0.0000%	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100%
TAXDEPR	Tax Depreciation	43.5570%	28.1956%	26.0434%	0.0349%	0.0000%	0.8586%	0.7556%	0.5547%	0.0000%	100%

Docket No. UE 433
Exhibit PAC/1905
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Ancillary Services Revenue Requirement

February 2024

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
Ancillary Services Revenue
12 Months Ended December 31, 2025 Forecast

Oregon Annual Ancillary Service Revenue $24,138,546

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)		29,457
2	Total Oregon Retail Load (MWh)		17,203,230
3			
4	Schedule 3 Load Rate ($/MW-month)		$115
5	Schedule 3 Revenue	1*4	$3,402,039
6			
7	Schedule 5 Rate ($/MWh)		$0.168
8	Schedule 5 Revenue	2*7	$2,884,982
9			
10	Schedule 6 Rate ($/MWh)		$0.168
11	Schedule 6 Revenue	2*10	$2,884,982
12			
13			
14	Total Oregon Load Revenue	5+8+11	$9,172,002

Generation

Line	Description	Calculation	Value
1	Sum of 12 Total System Solar VER Generator Nameplate Capacities (MW)[2]		21,662
2	Sum of 12 Total System Wind VER Generator Nameplate Capacities (MW)[2]		42,550
3	Sum of 12 Total System Non-VER Generator Nameplate Capacities (MW)		9,306
4	Total System Generation MWh at input		57,900,603
5			
6	Schedule 3A Solar VER Rate ($/MW-month)		$465
7	Schedule 3A VER Revenue	1*6	$10,079,542
8			
9	Schedule 3A Wind VER Rate ($/MW-month)		$558
10	Schedule 3A VER Revenue	2*9	$23,729,612
11			
12	Schedule 3A Non-VER Rate ($/MW-month)		$262
13	Schedule 3A Non-VER Revenue	3*12	$2,441,482
14			
15	Schedule 5 Rate ($/MWh)		$0.168
16	Schedule 5 Revenue	4*15	$9,709,931
17			
18	Schedule 6 Rate ($/MWh)		$0.168
19	Schedule 6 Revenue	4*18	$9,709,931
20			
21			
22	Total Generation Revenue	6+9+12+15	$55,670,499
23			
24	Oregon JAM SG Factor		27%
25	Oregon-allocated Total Generation Revenue	18*20	$14,966,544

[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 433
Exhibit PAC/1906
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

February 2024

STATE OF OREGON
Oregon Marginal Cost Study
20 Year Marginal Cost By Load Class
12 Months Ended December 31, 2025 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		Sch 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	$387,461	$173,067	$14,432	$15,502	$47	$11,010	$16,705	$23,893	$512	$4,244	$26,009	$1,788	$10,619	$11,751	$2,401	$34,151	$36,040	$5,291	$0
3	Transmission	$17,603	$7,863	$656	$704	$2	$500	$759	$1,085	$23	$193	$1,182	$81	$482	$534	$109	$1,552	$1,637	$240	$0
4	Distribution	$192,240	$102,489	$10,734	$10,646	$29	$6,019	$9,285	$12,889	$245	$1,834	$10,883	$719	$6,332	$6,747	$402	$4,773	$0	$8,182	$35
5	Poles	$53,771	$28,252	$3,137	$3,390	$10	$1,710	$2,564	$3,602	$76	$449	$2,630	$187	$2,125	$2,364	$0	$0	$0	$3,272	$3
6	Conductor	$68,757	$37,460	$3,646	$3,939	$12	$2,205	$3,307	$4,646	$98	$668	$3,956	$278	$2,459	$2,736	$0	$0	$0	$3,344	$4
7	Substations	$53,986	$28,220	$2,102	$2,271	$7	$1,618	$2,426	$3,408	$72	$608	$3,671	$254	$1,481	$1,648	$336	$4,773	$0	$1,093	$0
8	Transformers	$15,726	$8,557	$1,849	$1,045	$0	$485	$988	$1,232	$0	$108	$627	$0	$267	$0	$66	$0	$0	$473	$28
9	Total Demand	$789,543	$385,907	$36,554	$37,497	$106	$23,547	$36,033	$50,757	$1,026	$8,104	$48,956	$3,308	$23,764	$25,780	$3,313	$45,248	$37,677	$21,895	$71
10																				
11																				
12	Energy Related Marginal Cost																			
13	Generation	$1,282,011	$641,433	$244,673	$23,481	$25,569	$78	$17,980	$27,744	$40,656	$893	$7,215	$45,734	$3,238	$19,281	$34,643	$4,779	$56,265	$78,417	$9,931
14	Transmission	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
15	Total Energy	$1,282,011	$641,433	$244,673	$23,481	$25,569	$78	$17,980	$27,744	$40,656	$893	$7,215	$45,734	$3,238	$19,281	$34,643	$4,779	$56,265	$78,417	$9,931
16																				
17	Customer Related Marginal Cost																			
18	Poles	$64,407	$48,393	$10,282	$2,191	$7	$461	$367	$227	$6	$13	$39	$3	$11	$8	$0	$0	$0	$2,400	$0
19	Conductor	$27,995	$21,034	$4,469	$952	$3	$200	$159	$99	$3	$6	$17	$1	$5	$4	$0	$0	$0	$1,043	$0
20	Transformers	$105,698	$62,918	$18,212	$4,883	$0	$4,108	$3,664	$2,477	$0	$258	$781	$0	$102	$0	$5	$0	$0	$8,290	$0
21	Service Drops	$58,411	$43,193	$8,142	$3,242	$0	$990	$805	$1,138	$0	$72	$548	$0	$268	$0	$13	$0	$0	$0	$0
22	Meters	$16,951	$12,794	$1,873	$453	$86	$155	$130	$473	$102	$41	$126	$71	$22	$103	$1	$43	$213	$264	$3
23	Meter Reading	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
24	Billing & Collections	$16,127	$12,891	$2,067	$440	$1	$157	$125	$77	$2	$7	$20	$1	$23	$17	$1	$7	$2	$96	$191
25	Uncollectables	$6,677	$5,958	$113	$24	$0	$77	$62	$38	$1	$22	$65	$4	$112	$81	$6	$34	$11	$69	$0
26	Customer Service / Other	$6,655	$5,492	$745	$159	$1	$52	$41	$26	$1	$3	$9	$1	$6	$4	$0	$2	$1	$37	$77
27	Total Customer (Commitment & Billing)	$302,921	$212,673	$45,903	$12,344	$99	$6,199	$5,352	$4,555	$114	$422	$1,605	$81	$548	$216	$27	$85	$227	$12,200	$271
28																				
29																				
30	Total Revenue @ Full MC																			
31	Generation	$1,028,894	$417,741	$37,913	$41,071	$125	$28,990	$44,449	$64,549	$1,405	$11,459	$71,742	$5,027	$29,900	$46,394	$7,180	$90,416	$114,457	$15,222	$855
32	Transmission	$17,603	$7,863	$656	$704	$2	$500	$759	$1,085	$23	$193	$1,182	$81	$482	$534	$109	$1,552	$1,637	$240	$0
33	Distribution	$448,751	$278,027	$51,839	$21,914	$39	$11,777	$14,279	$16,830	$254	$2,183	$12,267	$723	$6,717	$6,759	$420	$4,773	$0	$19,915	$35
34	Customer - Billing	$16,127	$12,891	$2,067	$440	$1	$157	$125	$77	$2	$7	$20	$1	$23	$17	$1	$7	$2	$96	$191
35	Customer - Metering	$16,951	$12,794	$1,873	$453	$86	$155	$130	$473	$102	$41	$126	$71	$22	$103	$1	$43	$213	$264	$3
36	Customer - Other	$6,655	$5,492	$745	$159	$1	$52	$41	$26	$1	$3	$9	$1	$6	$4	$0	$2	$1	$37	$77
37	Revenue (less Uncollectables)	$1,534,981	$734,807	$95,092	$64,741	$255	$41,631	$59,783	$83,040	$1,786	$13,886	$85,346	$5,904	$37,150	$53,811	$7,711	$96,792	$116,310	$35,774	$1,161
38																				
39	Customer - Uncollectables	$6,677	$5,958	$113	$24	$0	$77	$62	$38	$1	$22	$65	$4	$112	$81	$6	$34	$11	$69	$0
40	Total Revenue	$1,541,658	$740,765	$95,205	$64,765	$255	$41,708	$59,845	$83,079	$1,787	$13,907	$85,412	$5,908	$37,262	$53,892	$7,717	$96,825	$116,321	$35,843	$1,161

Docket No. UE 433
Exhibit PAC/1907
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Unbundled Revenue Requirement Allocation

February 2024

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
December 31, 2025 Unbundled Revenue Requirement Allocation by Load Class

Line	Description	Total	(A) Residential	(B) General Service	(C)	(D) General Service	(E)	(F) General Service	(G)	(H)	(I) Large Power Service	(J)	(K) Irrigation	(L) Lighting
				Sch 23		Sch 28		Sch 30			Sch 48		Sch 41	Schs 15, 51, 53, and 54
			(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)	
1	Total Operating Revenues	$1,670,831	$786,075	$159,656	$230	$209,460	$1,874	$112,053	$6,920	$51,960	$169,230	$136,366	$32,687	$4,319
2	MWh	15,276,984	5,787,620	1,160,255	1,877	2,043,261	21,451	1,252,474	77,805	570,908	2,171,323	1,934,880	234,910	20,221
3														
4	Functionalized 20 Year Full Marginal Costs - Class $													
5	Generation	$1,028,894	$417,741	$78,984	$125	$137,988	$1,405	$83,201	$5,027	$37,079	$136,811	$114,457	$15,222	$855
6	Transmission	$17,603	$7,863	$1,360	$2	$2,345	$23	$1,374	$81	$591	$2,085	$1,637	$240	$0
7	Distribution	$448,751	$278,027	$73,752	$39	$42,886	$254	$14,450	$723	$7,137	$11,532	$0	$19,915	$35
8	Customer - Billing	$16,127	$12,891	$2,507	$1	$359	$2	$27	$1	$24	$23	$2	$96	$191
9	Customer - Metering	$16,951	$12,794	$2,326	$86	$758	$102	$167	$71	$23	$145	$213	$264	$3
10	Customer - Other	$6,655	$5,492	$903	$1	$119	$1	$12	$1	$6	$6	$1	$37	$77
11	Total	$1,534,981	$734,807	$159,834	$255	$184,454	$1,786	$99,232	$5,904	$44,861	$150,602	$116,310	$35,774	$1,161
12														
13	Functional Revenue Requirement Allocation Factors													
14	Functionalized 20 Year Full Marginal Costs - Class % of Total													
15	Generation	100.00%	40.60%	7.68%	0.01%	13.41%	0.14%	8.09%	0.49%	3.60%	13.30%	11.12%	1.48%	0.08%
16	Transmission	100.00%	44.67%	7.73%	0.01%	13.32%	0.13%	7.81%	0.46%	3.36%	11.85%	9.30%	1.37%	0.00%
17	Distribution	100.00%	61.96%	16.44%	0.01%	9.56%	0.06%	3.22%	0.16%	1.59%	2.57%	0.00%	4.44%	0.01%
18	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%
19	Ancillary Service	100.00%	40.60%	7.68%	0.01%	13.41%	0.14%	8.09%	0.49%	3.60%	13.30%	11.12%	1.48%	0.08%
20	Customer - Billing	100.00%	79.94%	15.55%	0.01%	2.22%	0.01%	0.17%	0.01%	0.15%	0.15%	0.01%	0.60%	1.19%
21	Customer - Metering	100.00%	75.47%	13.72%	0.51%	4.47%	0.60%	0.99%	0.42%	0.13%	0.86%	1.26%	1.56%	0.02%
22	Customer - Other	100.00%	82.53%	13.57%	0.01%	1.79%	0.01%	0.18%	0.01%	0.09%	0.09%	0.01%	0.56%	1.15%
23	Embedded DSM - (MWh)	100.00%	37.88%	7.59%	0.01%	13.37%	0.14%	8.20%	0.51%	3.74%	14.21%	12.67%	1.54%	0.13%
24	Regulatory & Franchise - (Total Operating Revenues)	100.00%	47.05%	9.56%	0.01%	12.54%	0.11%	6.71%	0.41%	3.11%	10.13%	8.16%	1.96%	0.26%
25														
26														
27	Functionalized Class Revenue Requirement - (Target)													
28	Generation	$957,412	$388,719	$73,497	$116	$128,401	$1,307	$77,421	$4,677	$34,503	$127,306	$106,505	$14,164	$795
29	Transmission	$316,015	$141,155	$24,414	$38	$42,092	$417	$24,674	$1,458	$10,619	$37,438	$29,394	$4,315	$0
30	Distribution	$411,711	$255,078	$67,665	$36	$39,346	$233	$13,258	$663	$6,548	$10,580	$0	$18,271	$32
31	Distribution Lighting	$3,282	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,282
32	Distribution Total	$414,992	$255,078	$67,665	$36	$39,346	$233	$13,258	$663	$6,548	$10,580	$0	$18,271	$3,314
33	Ancillary Services	$23,961	$9,728	$1,839	$3	$3,213	$33	$1,938	$117	$864	$3,186	$2,665	$354	$20
34	Customer - Billing	$16,617	$13,283	$2,584	$2	$369	$2	$28	$1	$25	$24	$2	$99	$197
35	Customer - Metering	$19,394	$14,637	$2,662	$99	$867	$117	$191	$81	$26	$166	$244	$302	$3
36	Customer - Other	$9,976	$8,233	$1,354	$1	$179	$1	$18	$1	$9	$9	$1	$56	$115
37	Embedded DSM - (MWh)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
38	Franchise Fees	$48,559	$22,845	$4,640	$7	$6,087	$54	$3,257	$201	$1,510	$4,918	$3,963	$950	$126
39	Total	$1,806,926	$853,679	$178,655	$301	$220,556	$2,164	$120,784	$7,201	$54,104	$183,627	$142,775	$38,512	$4,570
40														
41	Ratio of Operating Revn to Revenue Requirement-(Target)	92.47%	92.08%	89.37%	76.53%	94.97%	86.58%	92.77%	96.09%	96.04%	92.16%	95.51%	84.87%	94.52%
42	(Line 1 / Line 39)													
43	Increase or (Decrease)	$136,095	$67,604	$18,998	$71	$11,095	$290	$8,730	$281	$2,144	$14,397	$6,409	$5,825	$251
44	(Line 39 - Line 1)													
45														
46														
47	Percent Increase (Decrease)	8.15%	8.60%	11.90%	30.67%	5.30%	15.50%	7.79%	4.07%	4.13%	8.51%	4.70%	17.82%	5.80%
48	(Line 43 / Line 1)													

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
Oregon Marginal Cost Study
December 31, 2025 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	$936,890	$259,747	$368,771	$2,853	$24,139	$15,969	$17,101	$9,759	$45,708	$1,680,937
2											
3	Percent of Total	55.74%	15.45%	21.94%	0.17%	1.44%	0.95%	1.02%	0.58%	2.72%	100.00%
4											
5	Revenue From Classes Included in MC Study	$931,257	$258,185	$366,554	$2,836	$23,993	$15,873	$16,998	$9,701	$45,434	$1,670,831
6											
7	Other Revenues										
8	Schedule 4 - Employee Discount										($445)
9	Partial Requirements - Sch. 47 pri										$3,850
10	Partial Requirements - Sch. 47 trn										$1,198
11	Sch 848										$1,517
12	Oregon Direct Access Opt Out Amortization										$1,769
13	AGA										$4,071
14	Paperless Credit										($1,855)
15	Total Oregon Situs Revenue										$1,680,937

PACIFICORP
STATE OF OREGON
Combined GRC and TAM
Oregon Marginal Cost Study
December 31, 2025 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	$964,518	$318,360	$414,766	$3,306	$24,139	$16,740	$19,538	$10,050	$48,919	$1,820,337	
2												
3	Percent of Total	52.99%	17.49%	22.79%	0.18%	1.33%	0.92%	1.07%	0.55%	2.69%	100.00%	
4												Increase
5	Revenue From Classes Included in MC Study	$957,412	$316,015	$411,711	$3,282	$23,961	$16,617	$19,394	$9,976	$48,559	$1,806,926	$136,095
6												
7	Other Revenues											$139,399
8	Schedule 4 - Employee Discount										($482)	($37)
9	Partial Requirements - Sch. 47 pri										$4,544	$694
10	Partial Requirements - Sch. 47 trn										$1,533	$335
11	Sch 848										$3,829	$2,312
12	Oregon Direct Access Opt Out Amortization										$1,769	$0
13	AGA										$4,071	$0
14	Paperless Credit										($1,855)	$0
15	Total Oregon Situs Revenue										$1,820,336	

PACIFICORP
State of Oregon
December 31, 2025 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	$316,015	$141,155	$24,414	$38	$42,092	$417	$24,674	$1,458	$10,619	$37,438	$29,394	$4,315	$0
2														
3	FERC Transmission													
4	Peak MW @ Input	2,579	1,107	192	99	330	3	194	11	83	294	231	34	1
5	% of Total		42.94%	7.43%	3.85%	12.80%	0.13%	7.51%	0.44%	3.23%	11.39%	8.94%	1.31%	0.04%
6	FERC Transmission Revenues ($ 000)	$91,066	$39,102	$6,763	$3,502	$11,660	$116	$6,835	$404	$2,942	$10,371	$8,143	$1,195	$33
7														
8	Other Transmission Revenue Requirement	$224,949	$102,053	$17,651	($3,464)	$30,432	$302	$17,839	$1,054	$7,677	$27,067	$21,252	$3,120	($33)

	OR CP (MW)
Jan	2,814
Feb	2,631
Mar	2,502
Apr	2,365
May	1,993
Jun	2,319
Jul	2,745
Aug	2,591
Sep	2,093
Oct	2,190
Nov	2,580
Dec	2,634
Annual Average	2,455

Network service rate ($/MW-year)[1]	$37,098
FERC Transmission Revenues	$91,066,068

[1]From 2023 Transmission Formula Rate Annual Update p.14

Docket No. UE 433
Exhibit PAC/1908
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

February 2024

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 2025 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 2025.

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 are based on a forecast cost of a storage resource, described in the Company's Integrated Resource Plan, and wholesale market purchases consistent with the Company's most recent avoided cost calculations. The marginal generation capacity costs are determined using the cost per kW-year of the storage resource adjusted for the capacity contribution of the resource and the forecast energy benefit. The generation energy costs are determined by deducting a capacity credit from the forecast market prices recognizing that a firm market purchase can be relied upon to meet the company's peak load requirements.

The marginal generation calculation can be seen in the marginal cost study on page "Marginal Generation Costs" (Sheet 'Generation'). A summarized version of this page is "Summary of Marginal Costs in Nominal Dollars" (Sheet 'Table 4').

MARGINAL TRANSMISSION COSTS
The calculation of transmission costs are based on a five-year (2024-2028) 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 2025 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 'Transm'). 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 'XFMR2'). Transformer demand costs and commitment costs are shown on page "Transformer Demand and Commitment Costs" (Sheet 'XFMR1').

Marginal costs of distribution poles and wires are calculated using the Company's Distribution Circuit Model (Sheets 'PC2' through 'PC8'). 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 2024 - 2028. 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 "Distribution Substation Costs / kW 2025 Dollars" (Sheet 'DistSub') shows the annualized cost in $/kW and the detail of the substation calculation.

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.

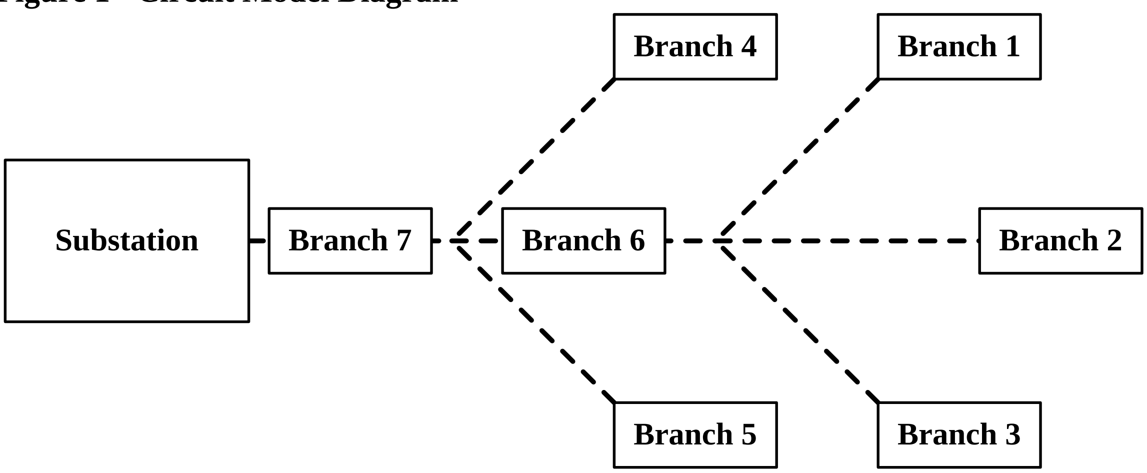
Weighted average installed service drop cost calculations are located on Sheet ‘Services’ and the weighted average installed meter cost calculations are included on Sheet ‘Meters’. The customer accounting and informational expense calculation is on page "Summary of Customer Accounting Expense by Schedule” (Sheet ‘CustExpense’). 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/1908, Sheets PC 2 through PC 8 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 26.89 poles per mile to the state average poles per mile. For example, Oregon has an average of 26.56 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)	0.37%	0.37%	0.37%	1.81%	1.81%	1.81%	93.46%	100.00%
GS - Schedule 23 - 0-15 kW (sec)	0.69%	0.69%	0.69%	2.57%	2.57%	2.57%	90.19%	100.00%
GS - Schedule 23 - 15+ kW (sec)	0.69%	0.69%	0.69%	2.57%	2.57%	2.57%	90.19%	100.00%
GS - Schedule 23 - Primary (pri)	0.69%	0.69%	0.69%	2.57%	2.57%	2.57%	90.19%	100.00%
GS - Schedule 28 - 0-50 kW (sec)	0.48%	0.48%	0.48%	1.52%	1.52%	1.52%	94.00%	100.00%
GS - Schedule 28 - 51-100 kW (sec)	0.48%	0.48%	0.48%	1.52%	1.52%	1.52%	94.00%	100.00%
GS - Schedule 28 - 100 + kW (sec)	0.48%	0.48%	0.48%	1.52%	1.52%	1.52%	94.00%	100.00%
GS - Schedule 28 - Primary (pri)	0.48%	0.48%	0.48%	1.52%	1.52%	1.52%	94.00%	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%	0.85%	0.85%	0.85%	96.61%	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	1.08%	1.08%	1.08%	7.97%	7.97%	7.97%	72.85%	100.00%
LPS - Schedule 48 - 1 - 4 MW (sec)	0.85%	0.85%	0.85%	1.52%	1.52%	1.52%	92.89%	100.00%
LPS - Schedule 48 - 1 - 4 MW (pri)	0.85%	0.85%	0.85%	1.52%	1.52%	1.52%	92.89%	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)	3.71	3.71	3.71	18.21	18.21	18.21	939.93	1,005.68
GS - Schedule 23 - 0-15 kW (sec)	0.93	0.93	0.93	3.45	3.45	3.45	121.01	134.17
GS - Schedule 23 - 15+ kW (sec)	0.20	0.20	0.20	0.74	0.74	0.74	25.79	28.59
GS - Schedule 23 - Primary (pri)	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.09
GS - Schedule 28 - 0-50 kW (sec)	0.04	0.04	0.04	0.13	0.13	0.13	8.06	8.57
GS - Schedule 28 - 51-100 kW (sec)	0.03	0.03	0.03	0.10	0.10	0.10	6.41	6.82
GS - Schedule 28 - 100 + kW (sec)	0.02	0.02	0.02	0.06	0.06	0.06	3.98	4.23
GS - Schedule 28 - Primary (pri)	0.00	0.00	0.00	0.00	0.00	0.00	0.10	0.11
GS - Schedule 30 - 0-300 kW (sec)	0.00	0.00	0.00	0.00	0.00	0.00	0.36	0.37
GS - Schedule 30 - 300+ kW (sec)	0.00	0.00	0.00	0.01	0.01	0.01	1.09	1.13
GS - Schedule 30 - Primary (pri)	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.08
Irrigation - Sch 41	0.13	0.13	0.13	0.92	0.92	0.92	8.45	11.60
LPS - Schedule 48 - 1 - 4 MW (sec)	0.00	0.00	0.00	0.00	0.00	0.00	0.14	0.15
LPS - Schedule 48 - 1 - 4 MW (pri)	0.00	0.00	0.00	0.00	0.00	0.00	0.10	0.11
LPS - Schedule 48 - > 4 MW (sec)	-	-	-	-	-	-	-	-
LPS - Schedule 48 - > 4 MW (pri)	-	-	-	-	-	-	-	-
Total	5.06	5.06	5.06	23.65	23.65	23.65	1,115.58	1,201.72

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)	8.43	8.43	8.43	41.45	41.45	41.45	2,139.10	2,288.76
GS - Schedule 23 - 0-15 kW (sec)	1.18	1.18	1.18	4.39	4.39	4.39	153.76	170.48
GS - Schedule 23 - 15+ kW (sec)	1.28	1.28	1.28	4.74	4.74	4.74	166.14	184.21
GS - Schedule 23 - Primary (pri)	0.00	0.00	0.00	0.01	0.01	0.01	0.50	0.56
GS - Schedule 28 - 0-50 kW (sec)	0.63	0.63	0.63	1.99	1.99	1.99	123.35	131.23
GS - Schedule 28 - 51-100 kW (sec)	0.95	0.95	0.95	2.99	2.99	2.99	184.95	196.76
GS - Schedule 28 - 100 + kW (sec)	1.33	1.33	1.33	4.20	4.20	4.20	259.85	276.44
GS - Schedule 28 - Primary (pri)	0.03	0.03	0.03	0.09	0.09	0.09	5.54	5.90
GS - Schedule 30 - 0-300 kW (sec)	0.14	0.14	0.14	0.48	0.48	0.48	47.47	49.33
GS - Schedule 30 - 300+ kW (sec)	0.84	0.84	0.84	2.53	2.53	2.53	287.59	297.70
GS - Schedule 30 - Primary (pri)	0.06	0.06	0.06	0.20	0.20	0.20	20.05	20.84
Irrigation - Sch 41	0.96	0.96	0.96	7.06	7.06	7.06	64.56	88.61
LPS - Schedule 48 - 1 - 4 MW (sec)	1.02	1.02	1.02	1.83	1.83	1.83	111.61	120.14
LPS - Schedule 48 - 1 - 4 MW (pri)	1.15	1.15	1.15	2.06	2.06	2.06	125.83	135.45
LPS - Schedule 48 - > 4 MW (sec)	-	-	-	-	-	-	-	-
LPS - Schedule 48 - > 4 MW (pri)	-	-	-	-	-	-	-	-
Total	17.99	17.99	17.99	74.03	74.03	74.03	3,690.31	3,966.39

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
Wire Size	Pole Cost per Mile	Adjustment Factor	Adjusted Pole Cost	Conductor Cost per Mile	Construction Cost
1 Phase - 1/0 ACSR	$29,797	0.988	$29,425	$12,789	$42,214
3 Phase - 1/0 ACSR	$56,836	0.988	$56,127	$28,548	$84,675
3 Phase - 447 AAC & 4\0 AAC	$63,338	0.988	$62,548	$62,952	$125,500
3 Phase -795 AAC & 477 AAC	$65,804	0.988	$64,984	$110,173	$175,157

	Costs for Branches 1,2,3,4,5		
	1 Phase - 1/0 ACSR	3 Phase - 1/0 ACSR	Total
Poles	$55,405	$196,266	$251,670
Conductors	$24,080	$99,826	$123,907
Total	$79,485	$296,092	$375,577

	Costs for Branch 6	Cost for Branch 7
	3 Phase - 447 AAC & 4\0 AAC	3 Phase -795 AAC & 477 AAC
Poles	$336,490	$349,591
Conductors	$338,662	$592,695
Total	$675,151	$942,286

Miles per Branch	5.38
Single Phase Miles Per Branch	1.88
Three Phase Miles Per Branch	3.50

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

	Poles			Conductor			
	Total Cost	Commitment	Demand	Total Cost	Commitment	Demand	Total
Branches 1,2,3,4,5							
1 Phase - 1/0 ACSR	$55,405	$55,405	$0	$24,080	$24,080	$0	$79,485
3 Phase - 1/0 ACSR	$196,266	$102,895	$93,371	$99,826	$44,720	$55,106	$296,092
Total Branches 1,2,3,4,5	$251,670	$158,300	$93,371	$123,907	$68,801	$55,106	$375,577
Branch 6							$0
3 Phase - 447 AAC & 4\0 AAC	$336,490	$158,300	$178,190	$338,662	$68,801	$269,861	$675,151
Branch 7							$0
3 Phase -795 AAC & 477 AAC	$349,591	$158,300	$191,291	$592,695	$68,801	$523,895	$942,286
Total All Branches	$1,944,433	$1,108,097	$836,335	$1,550,890	$481,605	$1,069,285	$3,495,323

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 and Conductors Demand Calculations, Cost Assignment

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
	Poles								
	1	2	3	4	5	6	7	Total	
% customer	14.06%	14.06%	14.06%			57.83%		100.00%	
Branch 6 Cost	$ 25,045	$ 25,045	$ 25,045			$ 103,055		$ 178,190	$ / kW
% customer	0.45%	0.45%	0.45%	1.87%	1.87%	1.87%	93.04%	100.00%	
Branch 7 Cost	$ 868	$ 868	$ 868	$ 3,571	$ 3,571	$ 3,571	$ 177,976	$ 191,291	
Branch Commitment Cost	$ 93,371	$ 93,371	$ 93,371	$ 93,371	$ 93,371				Average
Total	$ 119,284	$ 119,284	$ 119,284	$ 96,941	$ 96,941	$ 106,625	$ 177,976	$ 836,335	$ 210.86
Class Cost per Branch	1	2	3	4	5	6	7	Total Demand Cost	$ Per kW
Res - Schedule 4 (sec)	$ 55,912	$ 55,912	$ 55,912	$ 54,276	$ 54,276	$ 59,698	$ 103,165	$ 439,152	$ 191.87
GS - Schedule 23 - 0-15 kW (sec)	$ 7,847	$ 7,847	$ 7,847	$ 5,747	$ 5,747	$ 6,321	$ 7,416	$ 48,771	$ 286.09
GS - Schedule 23 - 15+ kW (sec)	$ 8,479	$ 8,479	$ 8,479	$ 6,210	$ 6,210	$ 6,830	$ 8,013	$ 52,700	$ 286.09
GS - Schedule 23 - Primary (pri)	$ 26	$ 26	$ 26	$ 19	$ 19	$ 21	$ 24	$ 159	$ 286.09
GS - Schedule 28 - 0-50 kW (sec)	$ 4,180	$ 4,180	$ 4,180	$ 2,612	$ 2,612	$ 2,873	$ 5,949	$ 26,584	$ 202.58
GS - Schedule 28 - 51-100 kW (sec)	$ 6,267	$ 6,267	$ 6,267	$ 3,916	$ 3,916	$ 4,307	$ 8,920	$ 39,859	$ 202.58
GS - Schedule 28 - 100 + kW (sec)	$ 8,805	$ 8,805	$ 8,805	$ 5,502	$ 5,502	$ 6,051	$ 12,532	$ 56,002	$ 202.58
GS - Schedule 28 - Primary (pri)	$ 188	$ 188	$ 188	$ 117	$ 117	$ 129	$ 267	$ 1,195	$ 202.58
GS - Schedule 30 - 0-300 kW (sec)	$ 912	$ 912	$ 912	$ 631	$ 631	$ 694	$ 2,289	$ 6,981	$ 141.52
GS - Schedule 30 - 300+ kW (sec)	$ 5,583	$ 5,583	$ 5,583	$ 3,308	$ 3,308	$ 3,639	$ 13,870	$ 40,874	$ 137.30
GS - Schedule 30 - Primary (pri)	$ 385	$ 385	$ 385	$ 266	$ 266	$ 293	$ 967	$ 2,949	$ 141.52
Irrigation - Sch 41	$ 6,363	$ 6,363	$ 6,363	$ 9,242	$ 9,242	$ 10,165	$ 3,113	$ 50,853	$ 573.90
LPS - Schedule 48 - 1 - 4 MW (sec)	$ 6,739	$ 6,739	$ 6,739	$ 2,396	$ 2,396	$ 2,635	$ 5,383	$ 33,025	$ 274.88
LPS - Schedule 48 - 1 - 4 MW (pri)	$ 7,597	$ 7,597	$ 7,597	$ 2,701	$ 2,701	$ 2,971	$ 6,068	$ 37,233	$ 274.88
LPS - Schedule 48 - > 4 MW (sec)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LPS - Schedule 48 - > 4 MW (pri)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Check Total	$ 119,284	$ 119,284	$ 119,284	$ 96,941	$ 96,941	$ 106,625	$ 177,976	$ 836,335	

	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
	Conductors								
	1	2	3	4	5	6	7	Total	
% customer	14.06%	14.06%	14.06%			57.83%		100.00%	
Branch 6 Cost	$ 37,929.76	$ 37,929.76	$ 37,929.76	$ -	$ -	$ 156,071.59	$ -	$ 269,861	$ / kW
% customer	0.45%	0.45%	0.45%	1.87%	1.87%	1.87%	93.04%	100.00%	
Branch 7 Cost	$ 2,377	$ 2,377	$ 2,377	$ 9,779	$ 9,779	$ 9,779	$ 487,429	$ 523,895	
Branch Commitment Cost	$ 55,106	$ 55,106	$ 55,106	$ 55,106	$ 55,106				Average
Total	$ 95,412	$ 95,412	$ 95,412	$ 64,885	$ 64,885	$ 165,850	$ 487,429	$ 1,069,285	$ 269.59
Class Cost per Branch	1	2	3	4	5	6	7	Total Demand Cost	$ Per kW
Res - Schedule 4 (sec)	$ 44,723	$ 44,723	$ 44,723	$ 36,328	$ 36,328	$ 92,857	$ 282,540	$ 582,222	$ 254.38
GS - Schedule 23 - 0-15 kW (sec)	$ 6,277	$ 6,277	$ 6,277	$ 3,846	$ 3,846	$ 9,832	$ 20,309	$ 56,664	$ 332.38
GS - Schedule 23 - 15+ kW (sec)	$ 6,782	$ 6,782	$ 6,782	$ 4,156	$ 4,156	$ 10,623	$ 21,945	$ 61,228	$ 332.38
GS - Schedule 23 - Primary (pri)	$ 20	$ 20	$ 20	$ 13	$ 13	$ 32	$ 66	$ 185	$ 332.38
GS - Schedule 28 - 0-50 kW (sec)	$ 3,343	$ 3,343	$ 3,343	$ 1,748	$ 1,748	$ 4,468	$ 16,293	$ 34,287	$ 261.28
GS - Schedule 28 - 51-100 kW (sec)	$ 5,013	$ 5,013	$ 5,013	$ 2,621	$ 2,621	$ 6,699	$ 24,429	$ 51,408	$ 261.28
GS - Schedule 28 - 100 + kW (sec)	$ 7,043	$ 7,043	$ 7,043	$ 3,682	$ 3,682	$ 9,413	$ 34,322	$ 72,228	$ 261.28
GS - Schedule 28 - Primary (pri)	$ 150	$ 150	$ 150	$ 79	$ 79	$ 201	$ 732	$ 1,541	$ 261.28
GS - Schedule 30 - 0-300 kW (sec)	$ 730	$ 730	$ 730	$ 422	$ 422	$ 1,079	$ 6,270	$ 10,382	$ 210.47
GS - Schedule 30 - 300+ kW (sec)	$ 4,466	$ 4,466	$ 4,466	$ 2,214	$ 2,214	$ 5,660	$ 37,986	$ 61,471	$ 206.49
GS - Schedule 30 - Primary (pri)	$ 308	$ 308	$ 308	$ 178	$ 178	$ 456	$ 2,648	$ 4,385	$ 210.47
Irrigation - Sch 41	$ 5,090	$ 5,090	$ 5,090	$ 6,186	$ 6,186	$ 15,812	$ 8,527	$ 51,980	$ 586.62
LPS - Schedule 48 - 1 - 4 MW (sec)	$ 5,390	$ 5,390	$ 5,390	$ 1,603	$ 1,603	$ 4,099	$ 14,741	$ 38,217	$ 318.09
LPS - Schedule 48 - 1 - 4 MW (pri)	$ 6,077	$ 6,077	$ 6,077	$ 1,808	$ 1,808	$ 4,621	$ 16,620	$ 43,087	$ 318.09
LPS - Schedule 48 - > 4 MW (sec)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LPS - Schedule 48 - > 4 MW (pri)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Check Total	$ 95,412	$ 95,412	$ 95,412	$ 64,885	$ 64,885	$ 165,850	$ 487,429	$ 1,069,285	

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 and Conductors Commitment Calculations, Cost Assignment

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
	Poles								
	1	2	3	4	5	6	7	Total	
% customer	13.04%	13.04%	13.04%			60.89%		100.00%	
Branch 6 Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ Per
% customer	0.42%	0.42%	0.42%	1.97%	1.97%	1.97%	92.83%	100.00%	Customer
Branch 7 Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Branch Commitment Cost	$ 158,300	$ 158,300	$ 158,300	$ 158,300	$ 158,300	$ 158,300	$ 158,300		Average
Total	$ 158,300	$ 158,300	$ 158,300	$ 158,300	$ 158,300	$ 158,300	$ 158,300	$ 1,108,097	$ 922.10
Class Cost per Branch	1	2	3	4	5	6	7	Total Demand Cost	$ Per Customer
Res - Schedule 4 (sec)	$ 115,850	$ 115,850	$ 115,850	$ 121,921	$ 121,921	$ 121,921	$ 133,375	$ 846,687	$ 841.90
GS - Schedule 23 - 0-15 kW (sec)	$ 29,122	$ 29,122	$ 29,122	$ 23,121	$ 23,121	$ 23,121	$ 17,171	$ 173,902	$ 1,296.15
GS - Schedule 23 - 15+ kW (sec)	$ 6,205	$ 6,205	$ 6,205	$ 4,927	$ 4,927	$ 4,927	$ 3,659	$ 37,055	$ 1,296.15
GS - Schedule 23 - Primary (pri)	$ 21	$ 21	$ 21	$ 16	$ 16	$ 16	$ 12	$ 123	$ 1,296.15
GS - Schedule 28 - 0-50 kW (sec)	$ 1,287	$ 1,287	$ 1,287	$ 872	$ 872	$ 872	$ 1,143	$ 7,621	$ 889.19
GS - Schedule 28 - 51-100 kW (sec)	$ 1,024	$ 1,024	$ 1,024	$ 694	$ 694	$ 694	$ 909	$ 6,063	$ 889.19
GS - Schedule 28 - 100 + kW (sec)	$ 636	$ 636	$ 636	$ 431	$ 431	$ 431	$ 564	$ 3,763	$ 889.19
GS - Schedule 28 - Primary (pri)	$ 17	$ 17	$ 17	$ 11	$ 11	$ 11	$ 15	$ 98	$ 889.19
GS - Schedule 30 - 0-300 kW (sec)	$ 33	$ 33	$ 33	$ 24	$ 24	$ 24	$ 51	$ 222	$ 594.22
GS - Schedule 30 - 300+ kW (sec)	$ 100	$ 100	$ 100	$ 64	$ 64	$ 64	$ 155	$ 649	$ 572.81
GS - Schedule 30 - Primary (pri)	$ 7	$ 7	$ 7	$ 5	$ 5	$ 5	$ 10	$ 45	$ 594.22
Irrigation - Sch 41	$ 3,929	$ 3,929	$ 3,929	$ 6,187	$ 6,187	$ 6,187	$ 1,199	$ 31,546	$ 2,718.91
LPS - Schedule 48 - 1 - 4 MW (sec)	$ 40	$ 40	$ 40	$ 15	$ 15	$ 15	$ 20	$ 187	$ 1,231.08
LPS - Schedule 48 - 1 - 4 MW (pri)	$ 29	$ 29	$ 29	$ 11	$ 11	$ 11	$ 14	$ 135	$ 1,231.08
LPS - Schedule 48 - > 4 MW (sec)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LPS - Schedule 48 - > 4 MW (pri)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Check Total	$ 158,300	$ 158,300	$ 158,300	$ 158,300	$ 158,300	$ 158,300	$ 158,300	$ 1,108,097	

	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
	Conductors								
	1	2	3	4	5	6	7	Total	
% customer	13.04%	13.04%	13.04%	0.00%	0.00%	60.89%	0.00%	100.00%	
Branch 6 Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ Per
% customer	0.42%	0.42%	0.42%	1.97%	1.97%	1.97%	92.83%	100.00%	Customer
Branch 7 Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Branch Commitment Cost	$ 68,801	$ 68,801	$ 68,801	$ 68,801	$ 68,801	$ 68,801	$ 68,801		Average
Total	$ 68,801	$ 68,801	$ 68,801	$ 68,801	$ 68,801	$ 68,801	$ 68,801	$ 481,605	$ 400.76
Class Cost per Branch	1	2	3	4	5	6	7	Total Demand Cost	$ Per Customer
Res - Schedule 4 (sec)	$ 50,351	$ 50,351	$ 50,351	$ 52,990	$ 52,990	$ 52,990	$ 57,968	$ 367,990	$ 365.91
GS - Schedule 23 - 0-15 kW (sec)	$ 12,657	$ 12,657	$ 12,657	$ 10,049	$ 10,049	$ 10,049	$ 7,463	$ 75,582	$ 563.34
GS - Schedule 23 - 15+ kW (sec)	$ 2,697	$ 2,697	$ 2,697	$ 2,141	$ 2,141	$ 2,141	$ 1,590	$ 16,105	$ 563.34
GS - Schedule 23 - Primary (pri)	$ 9	$ 9	$ 9	$ 7	$ 7	$ 7	$ 5	$ 53	$ 563.34
GS - Schedule 28 - 0-50 kW (sec)	$ 559	$ 559	$ 559	$ 379	$ 379	$ 379	$ 497	$ 3,312	$ 386.46
GS - Schedule 28 - 51-100 kW (sec)	$ 445	$ 445	$ 445	$ 302	$ 302	$ 302	$ 395	$ 2,635	$ 386.46
GS - Schedule 28 - 100 + kW (sec)	$ 276	$ 276	$ 276	$ 187	$ 187	$ 187	$ 245	$ 1,635	$ 386.46
GS - Schedule 28 - Primary (pri)	$ 7	$ 7	$ 7	$ 5	$ 5	$ 5	$ 6	$ 43	$ 386.46
GS - Schedule 30 - 0-300 kW (sec)	$ 14	$ 14	$ 14	$ 11	$ 11	$ 11	$ 22	$ 97	$ 258.26
GS - Schedule 30 - 300+ kW (sec)	$ 44	$ 44	$ 44	$ 28	$ 28	$ 28	$ 67	$ 282	$ 248.96
GS - Schedule 30 - Primary (pri)	$ 3	$ 3	$ 3	$ 2	$ 2	$ 2	$ 5	$ 20	$ 258.26
Irrigation - Sch 41	$ 1,708	$ 1,708	$ 1,708	$ 2,689	$ 2,689	$ 2,689	$ 521	$ 13,711	$ 1,181.70
LPS - Schedule 48 - 1 - 4 MW (sec)	$ 17	$ 17	$ 17	$ 7	$ 7	$ 7	$ 9	$ 81	$ 535.06
LPS - Schedule 48 - 1 - 4 MW (pri)	$ 13	$ 13	$ 13	$ 5	$ 5	$ 5	$ 6	$ 59	$ 535.06
LPS - Schedule 48 - > 4 MW (sec)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LPS - Schedule 48 - > 4 MW (pri)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Check Total	$ 68,801	$ 68,801	$ 68,801	$ 68,801	$ 68,801	$ 68,801	$ 68,801	$ 481,605	

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	
	Poles	Conductor
Construction Cost Per Mile	$64,984	$110,173
Average Trunk Length	0.67 miles	
Total Construction Cost	$43,539	$73,816
Customer Peak Demand (Sec)	3,591 kW	
Customer Peak Demand (Pri)	8,630 kW	
Demand Cost $/kW (Sec)	$12.13	$20.56
Demand Cost $/kW (Pri)	$5.04	$8.55

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

Load Class		Demand						Commitment					
				Investment $ / kW[1]		Annual $ / kW[1]				Investment $ / Customer		Annual $ / Customer	
		Poles	Conductor	Poles	Conductor	Poles	Conductor	Poles	Conductor	Poles	Conductor	Poles	Conductor
Res - Schedule 4	(sec)	$ 191.87	$ 254.38	$ 200.68	$ 266.06	$ 14.91	$ 19.77	$ 841.90	$ 365.91	$ 880.56	$ 382.71	$ 65.43	$ 28.44
GS - Schedule 23													
0-15 kW	(sec)	$ 286.09	$ 332.38	$ 299.22	$ 347.65	$ 22.23	$ 25.83	$ 1,296.15	$ 563.34	$ 1,355.66	$ 589.20	$ 100.73	$ 43.78
15+ kW	(sec)	$ 286.09	$ 332.38	$ 299.22	$ 347.65	$ 22.23	$ 25.83	$ 1,296.15	$ 563.34	$ 1,355.66	$ 589.20	$ 100.73	$ 43.78
Primary	(pri)	$ 286.09	$ 332.38	$ 299.22	$ 347.65	$ 22.23	$ 25.83	$ 1,296.15	$ 563.34	$ 1,355.66	$ 589.20	$ 100.73	$ 43.78
GS - Schedule 28													
0-50 kW	(sec)	$ 202.58	$ 261.28	$ 211.88	$ 273.27	$ 15.74	$ 20.30	$ 889.19	$ 386.46	$ 930.01	$ 404.21	$ 69.10	$ 30.03
51-100 kW	(sec)	$ 202.58	$ 261.28	$ 211.88	$ 273.27	$ 15.74	$ 20.30	$ 889.19	$ 386.46	$ 930.01	$ 404.21	$ 69.10	$ 30.03
100 + kW	(sec)	$ 202.58	$ 261.28	$ 211.88	$ 273.27	$ 15.74	$ 20.30	$ 889.19	$ 386.46	$ 930.01	$ 404.21	$ 69.10	$ 30.03
Primary	(pri)	$ 202.58	$ 261.28	$ 211.88	$ 273.27	$ 15.74	$ 20.30	$ 889.19	$ 386.46	$ 930.01	$ 404.21	$ 69.10	$ 30.03
GS - Schedule 30													
0-300 kW	(sec)	$ 141.52	$ 210.47	$ 148.02	$ 220.13	$ 11.00	$ 16.36	$ 594.22	$ 258.26	$ 621.50	$ 270.12	$ 46.18	$ 20.07
300+ kW	(sec)	$ 137.30	$ 206.49	$ 143.60	$ 215.97	$ 10.67	$ 16.05	$ 572.81	$ 248.96	$ 599.11	$ 260.39	$ 44.51	$ 19.35
Primary	(pri)	$ 141.52	$ 210.47	$ 148.02	$ 220.13	$ 11.00	$ 16.36	$ 594.22	$ 258.26	$ 621.50	$ 270.12	$ 46.18	$ 20.07
LPS - Schedule 48													
1 - 4 MW	(sec)	$ 274.88	$ 318.09	$ 287.50	$ 332.70	$ 21.36	$ 24.72	$ 1,231.08	$ 535.06	$ 1,287.60	$ 559.62	$ 95.67	$ 41.58
1 - 4 MW	(pri)	$ 274.88	$ 318.09	$ 287.50	$ 332.70	$ 21.36	$ 24.72	$ 1,231.08	$ 535.06	$ 1,287.60	$ 559.62	$ 95.67	$ 41.58
> 4 MW	(sec)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
> 4 MW	(pri)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Irrigation - Schedule 41	(sec)	$ 573.90	$ 586.62	$ 600.25	$ 613.55	$ 44.60	$ 45.59	$ 2,718.91	$ 1,181.70	$ 2,843.75	$ 1,235.96	$ 211.29	$ 91.83

Table 1

PacifiCorp
Oregon Marginal Cost Study
Summary of Marginal Costs
Demand & Energy in Mills/kWh
December 2025 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)	$89.56	$48.34	$42.28	$89.56	$96.03	$91.25
2								
3	GS - Schedule 23							
4	0-15 kW	(sec)	$89.56	$48.34	$42.28	$89.56	$93.72	$88.76
5	15+ kW	(sec)	$89.56	$48.34	$42.28	$89.56	$91.64	$86.67
6	Primary	(pri)	$88.17	$47.59	$41.62	$88.17	$87.84	$82.94
7								
8	GS - Schedule 28							
9	0-50 kW	(sec)	$89.56	$48.34	$42.28	$89.56	$88.45	$83.49
10	51-100 kW	(sec)	$89.56	$48.34	$42.28	$89.56	$88.01	$83.03
11	100 + kW	(sec)	$89.56	$48.34	$42.28	$89.56	$86.65	$81.65
12	Primary	(pri)	$88.17	$47.59	$41.62	$88.17	$82.95	$78.01
13								
14	GS - Schedule 30							
15	0-300 kW	(sec)	$89.56	$48.34	$42.28	$89.56	$84.01	$79.01
16	300+ kW	(sec)	$89.56	$48.34	$42.28	$89.56	$82.50	$77.47
17	Primary	(pri)	$88.17	$47.59	$41.62	$88.17	$79.88	$74.89
18								
19	LPS - Schedule 48							
20	1 - 4 MW	(sec)	$89.56	$48.34	$42.28	$89.56	$85.56	$80.50
21	1 - 4 MW	(pri)	$88.17	$6.67	$42.28	$88.17	$29.28	$65.50
22	> 4 MW	(sec)	$89.56	$344.97	$41.62	$89.56	$369.44	$66.98
23	> 4 MW	(pri)	$88.17	$47.59	$41.62	$88.17	$76.45	$71.56
24	Trans	(trm)	$85.86	$46.34	$40.53	$85.86	$67.64	$60.00
25								
26								
27	Schedule 41- Irrigation	(sec)	$89.56	$48.34	$42.28	$89.56	$105.75	$100.65
28								
29	Lighting	(sec)	$89.56	$48.34	$42.28	$89.56	$57.04	$44.02

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 2025 Dollars

Line	Description		(A) 1 Year	(B) 10 & 20 Year
1	Res - Schedule 4	(sec)	$13.03	$34.51
2				
3	GS - Schedule 23			
4	0-15 kW	(sec)	$15.21	$53.97
5	15+ kW	(sec)	$23.83	$68.11
6	Primary	(pri)	$171.38	$164.90
7				
8	GS - Schedule 28			
9	0-50 kW	(sec)	$25.74	$111.58
10	51-100 kW	(sec)	$26.30	$121.10
11	100 + kW	(sec)	$63.87	$166.06
12	Primary	(pri)	$149.27	$161.16
13				
14	GS - Schedule 30			
15	0-300 kW	(sec)	$73.78	$175.66
16	300+ kW	(sec)	$105.65	$220.82
17	Primary	(pri)	$157.18	$165.13
18				
19	LPS - Schedule 48			
20	1 - 4 MW	(sec)	$437.19	$557.32
21	1 - 4 MW	(pri)	$287.25	$303.72
22	> 4 MW	(sec)	$437.19	$540.85
23	> 4 MW	(pri)	$287.25	$287.25
24	Trans	(trn)	$2,360.30	$2,360.30
25				
26				
27	Schedule 41- Irrigation	(sec)	$7.89	$131.86
28				
29	Lighting	(sec)	$5.21	$36.50

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 2025 Dollars

Line	Calculation Component	Class	Units Description / Function	Total	(A) Residential (sec)	(B) General Service - Schedule 23 0-15 kW (sec)	(C) 15+ kW (sec)	(D) Primary (pri)	(E) General Service - Schedule 28 0-50 kW (sec)	(F) 51-100 kW (sec)	(G) 100 + kW (sec)	(H) Primary (pri)	(I) General Service - Schedule 30 0-300 kW (sec)	(J) 300+ kW (sec)	(K) Primary (pri)	(L) Large Power Service - Schedule 48 1 - 4 MW (sec)	(M) 1 - 4 MW (pri)	(N) > 4 MW (sec)	(O) > 4 MW (pri)	(P) Trn (trn)	(Q) Irrg - Sch 41 (sec)	(R) Lighting Schs 15, 51, 53, 54 (sec)
1	Units	Demand	Peak MW @ Input-System		1,107	92	99	0	70	107	153	3	27	166	11	68	75	15	219	231	34	1
2	Units	Demand	Peak MW @ Input-Distribution		1,316	98	106	0	75	113	159	3	28	171	12	69	77	16	223	-	51	0
3	Units	Demand	Peak MW @ Input-Transformer		3,665	792	448	-	208	423	528	-	46	268	-	114	-	28	-	-	203	12
4																						
5	Units	Energy	Annual MWh @ Input		6,248,604	599,673	652,997	1,995	459,186	708,531	1,038,290	22,801	184,262	1,167,972	82,702	492,415	884,743	122,047	1,436,937	2,002,659	253,620	21,832
6																						
7	Units	Customer	Average		513,581	70,880	15,103	50	4,630	3,683	2,286	59	200	606	41	82	59	4	25	8	3,311	7,437
8	Units	Customer	Annual - Metered		513,581	70,880	15,103	50	4,630	3,683	2,286	59	200	606	41	82	59	4	25	8	7,887	98
9																						
10																						
11	$/Unit	Demand	Generation ($/System Peak kW)		$156.28	$156.28	$156.28	$156.28	$156.28	$156.28	$156.28	$156.28	$156.28	$156.28	$156.28	$156.28	$156.28	$156.28	$156.28	$156.28	$156.28	$156.28
12	$/Unit	Demand	Transmission ($/System Peak kW)		$7.10	$7.10	$7.10	$7.10	$7.10	$7.10	$7.10	$7.10	$7.10	$7.10	$7.10	$7.10	$7.10	$7.10	$7.10	$7.10	$7.10	$0.00
13	$/Unit	Demand	Dist-Poles ($/Dist. kW)		$21.47	$32.01	$32.01	$32.01	$22.67	$22.67	$22.67	$22.67	$15.84	$15.37	$15.84	$30.76	$30.76	$0.00	$0.00	$0.00	$64.23	$32.01
14	$/Unit	Demand	Dist-Cond ($/Dist. kW)		$28.47	$37.20	$37.20	$37.20	$29.23	$29.23	$29.23	$29.23	$23.56	$23.11	$23.56	$35.60	$35.60	$0.00	$0.00	$0.00	$65.65	$37.20
15	$/Unit	Demand	Dist-Substation ($/Dist. kW)		$21.45	$21.45	$21.45	$21.45	$21.45	$21.45	$21.45	$21.45	$21.45	$21.45	$21.45	$21.45	$21.45	$21.45	$21.45	$0.00	$21.45	$0.00
16	$/Unit	Demand	Dist-Transformers ($/Xfmr kW)		$2.33	$2.33	$2.33	$0.00	$2.33	$2.33	$2.33	$0.00	$2.33	$2.33	$0.00	$2.33	$0.00	$2.33	$0.00	$0.00	$2.33	$2.33
17																						
18	$/Unit	Energy	Generation Energy @ Input ($/kWh)		$0.03916	$0.03916	$0.03916	$0.03916	$0.03916	$0.03916	$0.03916	$0.03916	$0.03916	$0.03916	$0.03916	$0.03916	$0.03916	$0.03916	$0.03916	$0.03916	$0.03916	$0.03916
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	$0.00000
20																						
21	$/Unit	Customer	Dist-Poles ($/Customer)		$94.23	$145.06	$145.06	$145.06	$99.51	$99.51	$99.51	$99.51	$66.50	$64.10	$66.50	$137.77	$137.77	$0.00	$0.00	$0.00	$304.28	$145.06
22	$/Unit	Customer	Dist-Conductor ($/Customer)		$40.96	$63.05	$63.05	$63.05	$43.25	$43.25	$43.25	$43.25	$28.90	$27.87	$28.90	$59.88	$59.88	$0.00	$0.00	$0.00	$132.24	$63.05
23	$/Unit	Customer	Dist-Transformers ($/Customer)		$122.51	$256.94	$323.32	$0.00	$887.22	$994.75	$1,083.62	$0.00	$1,286.48	$1,289.98	$0.00	$1,243.96	$0.00	$1,243.96	$0.00	$0.00	$1,051.07	$167.43
24	$/Unit	Customer	Dist-Service Drop ($/Customer)		$84.10	$114.88	$214.66	$0.00	$213.77	$218.49	$497.73	$0.00	$362.07	$903.85	$0.00	$3,265.83	$0.00	$3,265.83	$0.00	$0.00	$0.00	$0.00
25	$/Unit	Customer	Meters ($/Customer)		$24.91	$26.43	$30.00	$1,729.42	$33.37	$35.35	$206.86	$1,729.42	$207.21	$207.30	$1,729.42	$262.83	$1,729.42	$262.83	$1,729.42	$26,606.01	$33.45	$26.43
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	$0.00
27	$/Unit	Customer	Billing & Collections ($/Customer)		$25.10	$29.16	$29.16	$29.16	$33.83	$33.83	$33.83	$33.83	$33.83	$33.83	$33.83	$279.41	$279.41	$279.41	$279.41	$279.41	$29.14	$25.72
28	$/Unit	Customer	Uncollectables ($/Customer)		$11.60	$1.59	$1.59	$1.59	$16.70	$16.70	$16.70	$16.70	$108.13	$108.13	$108.13	$1,366.11	$1,366.11	$1,366.11	$1,366.11	$1,366.11	$20.91	$0.00
29	$/Unit	Customer	Customer Service / Other ($/Customer)		$10.69	$10.50	$10.50	$10.50	$11.26	$11.26	$11.26	$11.26	$14.74	$14.74	$14.74	$72.04	$72.04	$72.04	$72.04	$72.04	$11.24	$10.31
30																						
31																						
32	$000	Demand	Generation	$387,461	$173,067	$14,432	$15,502	$47	$11,010	$16,705	$23,893	$512	$4,244	$26,009	$1,788	$10,619	$11,751	$2,401	$34,151	$36,040	$5,291	$0
33	$000	Demand	Transmission	$17,603	$7,863	$656	$704	$2	$500	$759	$1,085	$23	$193	$1,182	$81	$482	$534	$109	$1,552	$1,637	$240	$0
34	$000	Demand	Dist-Poles	$53,771	$28,252	$3,137	$3,390	$10	$1,710	$2,564	$3,602	$76	$449	$2,630	$187	$2,125	$2,364	$0	$0	$0	$3,272	$3
35	$000	Demand	Dist-Conductor	$68,757	$37,460	$3,646	$3,939	$12	$2,205	$3,307	$4,646	$98	$668	$3,956	$278	$2,459	$2,736	$0	$0	$0	$3,344	$4
36	$000	Demand	Dist-Substations	$53,986	$28,220	$2,102	$2,271	$7	$1,618	$2,426	$3,408	$72	$608	$3,671	$254	$1,481	$1,648	$336	$4,773	$0	$1,093	$0
37	$000	Demand	Dist-Transformers	$15,726	$8,557	$1,849	$1,045	$0	$485	$988	$1,232	$0	$108	$627	$0	$267	$0	$66	$0	$0	$473	$28
38	$000	Demand	Total Demand	$597,303	$283,419	$25,821	$26,852	$78	$17,529	$26,749	$37,868	$780	$6,270	$38,073	$2,589	$17,433	$19,032	$2,912	$40,475	$37,677	$13,713	$35
39																						
40	$000	Energy	Generation	$641,433	$244,673	$23,481	$25,569	$78	$17,980	$27,744	$40,656	$893	$7,215	$45,734	$3,238	$19,281	$34,643	$4,779	$56,265	$78,417	$9,931	$855
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	$641,433	$244,673	$23,481	$25,569	$78	$17,980	$27,744	$40,656	$893	$7,215	$45,734	$3,238	$19,281	$34,643	$4,779	$56,265	$78,417	$9,931	$855
43																						
44	$000	Customer	Dist-Poles	$64,407	$48,393	$10,282	$2,191	$7	$461	$367	$227	$6	$13	$39	$3	$11	$8	$0	$0	$0	$2,400	$0
45	$000	Customer	Dist-Conductor	$27,995	$21,034	$4,469	$952	$3	$200	$159	$99	$3	$6	$17	$1	$5	$4	$0	$0	$0	$1,043	$0
46	$000	Customer	Dist-Transformers	$105,698	$62,918	$18,212	$4,883	$0	$4,108	$3,664	$2,477	$0	$258	$781	$0	$102	$0	$5	$0	$0	$8,290	$0
47	$000	Customer	Dist-Service Drop	$58,411	$43,193	$8,142	$3,242	$0	$990	$805	$1,138	$0	$72	$548	$0	$268	$0	$13	$0	$0	$0	$0
48	$000	Customer	Meters	$16,951	$12,794	$1,873	$453	$86	$155	$130	$473	$102	$41	$126	$71	$22	$103	$1	$43	$213	$264	$3
49	$000	Customer	Meter Reading	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
50	$000	Customer	Billing & Collections	$16,127	$12,891	$2,067	$440	$1	$157	$125	$77	$2	$7	$20	$1	$23	$17	$1	$7	$2	$96	$191
51	$000	Customer	Uncollectables	$6,677	$5,958	$113	$24	$0	$77	$62	$38	$1	$22	$65	$4	$112	$81	$6	$34	$11	$69	$0
52	$000	Customer	Customer Service / Other	$6,655	$5,492	$745	$159	$1	$52	$41	$26	$1	$3	$9	$1	$6	$4	$0	$2	$1	$37	$77
53	$000	Customer	Total Customer (Commitment & Billing)	$302,921	$212,673	$45,903	$12,344	$99	$6,199	$5,352	$4,555	$114	$422	$1,605	$81	$548	$216	$27	$85	$227	$12,200	$271
54																						
55																						
56			Total Revenue @ Full MC ($000)																			
57			Generation	$1,028,894	$417,741	$37,913	$41,071	$125	$28,990	$44,449	$64,549	$1,405	$11,459	$71,742	$5,027	$29,900	$46,394	$7,180	$90,416	$114,457	$15,222	$855
58			Transmission	$17,603	$7,863	$656	$704	$2	$500	$759	$1,085	$23	$193	$1,182	$81	$482	$534	$109	$1,552	$1,637	$240	$0
59			Distribution	$448,751	$278,027	$51,839	$21,914	$39	$11,777	$14,279	$16,830	$254	$2,183	$12,267	$723	$6,717	$6,759	$420	$4,773	$0	$19,915	$35
60			Customer - Billing	$16,127	$12,891	$2,067	$440	$1	$157	$125	$77	$2	$7	$20	$1	$23	$17	$1	$7	$2	$96	$191
61			Customer - Metering	$16,951	$12,794	$1,873	$453	$86	$155	$130	$473	$102	$41	$126	$71	$22	$103	$1	$43	$213	$264	$3
62			Customer - Other	$6,655	$5,492	$745	$159	$1	$52	$41	$26	$1	$3	$9	$1	$6	$4	$0	$2	$1	$37	$77
63			Total Revenue (less Uncollectables)	$1,534,981	$734,807	$95,092	$64,741	$255	$41,631	$59,783	$83,040	$1,786	$13,886	$85,346	$5,904	$37,150	$53,811	$7,711	$96,792	$116,310	$35,774	$1,161
64																						
65			Customer - Uncollectables	$6,677	$5,958	$113	$24	$0	$77	$62	$38	$1	$22	$65	$4	$112	$81	$6	$34	$11	$69	$0
66			Total Revenue	$1,541,658	$740,765	$95,205	$64,765	$255	$41,708	$59,845	$83,079	$1,787	$13,907	$85,412	$5,908	$37,262	$53,892	$7,717	$96,825	$116,321	$35,843	$1,161

Table 4

PacifiCorp
Oregon Marginal Cost Study
Summary of Marginal Generation Costs in Nominal Dollars

	(B)	(D)
	Energy Only ($/MWh)	Capacity Only ($/kW)
2023 (1 Year)	82.95	104.74
2023 - 2027 (5 Year, Short Run)	54.03	134.01
2023 - 2032 (10 Year, Medium Run)	44.77	149.62
2023 - 2042 (20 Year, Long Run)	39.16	156.28

Table 5

PacifiCorp
Oregon Marginal Cost Study
Marginal Cost of
Transmission Investment and Associated Expenses

Line	Item	$	
1	Growth Related Investments - (2024 to 2028 in $000s)	$271,101	
2			
3	System Growth MW from 2022 to 2026	3,211	
4			
5	Marginal Investment (line 1/line 3)	$84.43	/ kW
6			
7	Annualized Investment @ 6.75%	$5.70	/ kW
8	Admin. & General Factor @ 0.58%	$0.49	
9	Annual O&M Expenses @ 1.080%	$0.91	/ kW
10	Annualized Marginal Cost	$7.10	/ kW
11			
12	Marginal Cost of Demand-Related Transmission	$7.10	/ 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 77.88% LF))		

Table 6

PacifiCorp
Oregon Marginal Cost Study
Marginal Distribution & Billing Costs
2025 Dollars

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
		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	Trans		
Line	Description	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(sec)	(pri)	(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)	(sec)
1	Demand Costs ($/kW)																		
2																			
3	Dist-Poles	$14.91	$22.23	$22.23	$22.23	$15.74	$15.74	$15.74	$15.74	$11.00	$10.67	$11.00	$21.36	$21.36	$0.00	$0.00	$0.00	$44.60	
4	Dist-Conductors	$19.77	$25.83	$25.83	$25.83	$20.30	$20.30	$20.30	$20.30	$16.36	$16.05	$16.36	$24.72	$24.72	$0.00	$0.00	$0.00	$45.59	
5	Dist-Substation	$14.89	$14.89	$14.89	$14.89	$14.89	$14.89	$14.89	$14.89	$14.89	$14.89	$14.89	$14.89	$14.89	$14.89	$14.89	$0.00	$14.89	$14.89
6	Dist. O&M @ 44.01% of Investment	$21.82	$27.71	$27.71	$27.71	$22.42	$22.42	$22.42	$22.42	$18.60	$18.31	$18.60	$26.83	$26.83	$6.55	$6.55	$0.00	$46.25	$6.55
7	Total $/Dist. kW	$71.39	$90.66	$90.66	$90.66	$73.35	$73.35	$73.35	$73.35	$60.85	$59.93	$60.85	$87.81	$87.81	$21.45	$21.45	$0.00	$151.33	$21.45
8																			
9	Dist-Transformers	$1.62	$1.62	$1.62	$0.00	$1.62	$1.62	$1.62	$0.00	$1.62	$1.62	$0.00	$1.62	$0.00	$1.62	$0.00	$0.00	$1.62	$1.62
10	Dist. O&M @ 44.01% of Investment	$0.71	$0.71	$0.71	$0.00	$0.71	$0.71	$0.71	$0.00	$0.71	$0.71	$0.00	$0.71	$0.00	$0.71	$0.00	$0.00	$0.71	$0.71
11	Total $/Transformer kW	$2.33	$2.33	$2.33	$0.00	$2.33	$2.33	$2.33	$0.00	$2.33	$2.33	$0.00	$2.33	$0.00	$2.33	$0.00	$0.00	$2.33	$2.33
12																			
13																			
14																			
15	Customer Costs ($/Customer)																		
16																			
17	Commitment																		
18	Dist-Poles	$65.43	$100.73	$100.73	$100.73	$69.10	$69.10	$69.10	$69.10	$46.18	$44.51	$46.18	$95.67	$95.67	$0.00	$0.00	$0.00	$211.29	
19	Dist-Conductors	$28.44	$43.78	$43.78	$43.78	$30.03	$30.03	$30.03	$30.03	$20.07	$19.35	$20.07	$41.58	$41.58	$0.00	$0.00	$0.00	$91.83	
20	Dist-Transformers	$85.07	$178.42	$224.51	$0.00	$616.08	$690.75	$752.46	$0.00	$893.33	$895.76	$0.00	$863.80	$863.80	$0.00	$0.00	$0.00	$729.86	$116.26
21	Dist. O&M @ 44.01% of Investment	$78.75	$142.12	$162.41	$63.60	$314.76	$347.63	$374.78	$43.63	$422.31	$422.33	$29.16	$440.56	$440.56	$0.00	$0.00	$0.00	$454.61	$51.17
22	Total Commitment	$257.69	$465.05	$531.43	$208.11	$1,029.97	$1,137.51	$1,226.37	$142.76	$1,381.89	$1,381.95	$95.41	$1,441.61	$1,441.61	$0.00	$0.00	$0.00	$1,487.59	$167.43
23	Monthly Commitment	$21.47	$38.75	$44.29	$17.34	$85.83	$94.79	$102.20	$11.90	$115.16	$115.16	$7.95	$120.13	$120.13	$0.00	$0.00	$0.00	$123.97	$13.95
24																			
25	Billing																		
26	Dist-Service Drop	$58.40	$79.77	$149.06	$0.00	$148.44	$151.72	$345.62	$0.00	$362.07	$627.63	$0.00	$2,267.78	$2,267.78	$0.00	$0.00	$0.00	$0.00	$0.00
27	Dist. O&M @ 44.01% of Investment	$25.70	$35.11	$65.60	$0.00	$65.33	$66.77	$152.11	$0.00	$159.35	$276.22	$0.00	$998.05	$998.05	$0.00	$0.00	$0.00	$0.00	$0.00
28	Meter	$17.22	$18.27	$20.74	$1,195.51	$23.07	$24.44	$143.00	$1,195.51	$143.24	$143.30	$1,195.51	$181.69	$1,195.51	$181.69	$1,195.51	$18,392.10	$23.12	$18.27
29	Meter O&M @ 44.66% of Investment	$7.58	$8.04	$9.13	$526.14	$10.15	$10.76	$62.93	$526.14	$63.04	$63.07	$526.14	$79.96	$526.14	$79.96	$526.14	$8,094.36	$10.18	$8.04
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	$0.00
31	Billing & Collections	$29.16	$29.16	$29.16	$29.16	$33.83	$33.83	$33.83	$33.83	$33.83	$33.83	$33.83	$279.41	$279.41	$279.41	$279.41	$279.41	$29.14	$25.72
32	Uncollectables	$11.60	$1.59	$1.59	$1.59	$16.70	$16.70	$16.70	$16.70	$108.13	$108.13	$108.13	$1,366.11	$1,366.11	$1,366.11	$1,366.11	$1,366.11	$20.91	$0.00
33	Customer Service / Other	$10.69	$10.50	$10.50	$10.50	$11.26	$11.26	$11.26	$11.26	$14.74	$14.74	$14.74	$72.04	$72.04	$72.04	$72.04	$72.04	$11.24	$10.31
34	Total Billing	$160.36	$182.45	$285.79	$1,762.91	$308.79	$315.48	$765.46	$1,783.45	$884.40	$1,266.92	$1,878.36	$5,245.04	$6,705.05	$1,979.21	$3,439.22	$28,204.02	$94.59	$62.35
35	Monthly Billing	$13.36	$15.20	$23.82	$146.91	$25.73	$26.29	$63.79	$148.62	$73.70	$105.58	$156.53	$437.09	$558.75	$164.93	$286.60	$2,350.34	$7.88	$5.20
36																			
37	Total Customer (Commitment & Billing)	$418.05	$647.50	$817.21	$1,971.02	$1,338.76	$1,452.99	$1,991.83	$1,926.21	$2,266.29	$2,648.87	$1,973.76	$6,686.66	$8,146.66	$1,979.21	$3,439.22	$28,204.02	$1,582.18	$229.77
38	Monthly Customer (Commitment & Billing)	$34.84	$53.96	$68.10	$164.25	$111.56	$121.08	$165.99	$160.52	$188.86	$220.74	$164.48	$557.22	$678.89	$164.93	$286.60	$2,350.34	$131.85	$19.15
39																			

Table 7

PacifiCorp
Oregon Marginal Cost Study
20 Year Demand Costs Divided by Billing kW
December 2025 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	Lighting
				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)	(sec)
1	Marginal Cost ($000)																			
2																				
3	Generation	$387,461	$173,067	$14,432	$15,502	$47	$11,010	$16,705	$23,893	$512	$4,244	$26,009	$1,788	$10,619	$11,751	$2,401	$34,151	$36,040	$5,291	$0
4	Transmission	$17,603	$7,863	$656	$704	$2	$500	$759	$1,085	$23	$193	$1,182	$81	$482	$534	$109	$1,552	$1,637	$240	$0
5	Dist-Poles, Wire, Sub	$176,514	$93,932	$8,885	$9,600	$29	$5,533	$8,297	$11,657	$245	$1,726	$10,256	$719	$6,065	$6,747	$336	$4,773	$0	$7,709	$7
6	Dist-Transformers	$15,726	$8,557	$1,849	$1,045	$0	$485	$988	$1,232	$0	$108	$627	$0	$267	$0	$66	$0	$0	$473	$28
7																				
8	Average Billing kW @ Sales	$8,989,495	5,042,753	947,994	535,908	11,400	191,574	390,191	486,664	39,149	55,540	321,463	53,025	105,438	26,117	114,319	155,107	317,201	186,770	8,881
9																				
10	Generation ($/kW)		$34.32	$2.86	$3.07	$0.01	$2.18	$3.31	$4.74	$0.10	$0.84	$5.16	$0.35	$2.11	$2.33	$0.48	$6.77	$7.15	$1.05	$0.00
11	Transmission ($/kW)		$1.56	$0.13	$0.14	$0.00	$0.10	$0.15	$0.22	$0.00	$0.04	$0.23	$0.02	$0.10	$0.11	$0.02	$0.31	$0.32	$0.05	$0.00
12	Dist-Poles, Wire, Sub ($/kW)		$18.63	$1.76	$1.90	$0.01	$1.10	$1.65	$2.31	$0.05	$0.34	$2.03	$0.14	$1.20	$1.34	$0.07	$0.95	$0.00	$1.53	$0.00
13	Dist-Transformers ($/kW)		$1.70	$0.37	$0.21	$0.00	$0.10	$0.20	$0.24	$0.00	$0.02	$0.12	$0.00	$0.05	$0.00	$0.01	$0.00	$0.00	$0.09	$0.01
14																				
15	Total Demand Related		$56.20	$5.12	$5.32	$0.02	$3.48	$5.30	$7.51	$0.15	$1.24	$7.55	$0.51	$3.46	$3.77	$0.58	$8.03	$7.47	$2.72	$0.01
16	Monthly Demand Related		$4.68	$0.43	$0.44	$0.00	$0.29	$0.44	$0.63	$0.01	$0.10	$0.63	$0.04	$0.29	$0.31	$0.05	$0.67	$0.62	$0.23	$0.00

Table 8

PacifiCorp
Oregon Marginal Cost Study
Marginal Cost Percentage
December 2025 Dollars

Line	Description	(A) Marginal Cost (000s)	(B) Mills / kWh	(C) % of Total
1	Demand Related Marginal Cost			
2	Generation	$387,461	25.36	25%
3	Transmission	$17,603	1.15	1%
4	Dist. Poles, Cond., Subst.	$176,514	11.55	11%
5	Dist. Transformers	$15,726	1.03	1%
6	Total Demand Related	$597,303	39.09	39%
7				
8	Energy Related Marginal Cost			
9	Generation	$641,433	41.99	42%
10	Transmission	$0	-	0%
11	Total Energy Related	641432.9875	41.99	42%
12				
13	Commitment & Billing			
14	Commitment	$198,100	12.97	13%
15	Billing	$104,821	6.86	7%
16	Total Commitment & Billing	302921.2976	19.83	20%
17				
18				
19	TOTAL MARGINAL COST	$1,541,658	100.91	100%
20				
21				
22		Note: Total MWh @ Sales =	15,276,984	

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)	(Q)
					Residential	General Service - Schedule 23			General Service - Schedule 28				General Service - Schedule 30			Large Power Service - Schedule 48					Irrg - Sch 41	Lighting
	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)	(sec)
1	Units	Demand	Peak MW @ Input-System		1,107	92	99	0	70	107	153	3	27	166	11	68	75	15	219	231	34	1
2	Units	Demand	Peak MW @ Input-Distribution		1,316	98	106	0	75	113	159	3	28	171	12	69	77	16	223	237	51	0
3	Units	Demand	Peak MW @ Input-Transformer		3,665	792	448	12	208	423	528	42	46	268	57	114	122	28	166	329	203	12
4																						
5	Units	Energy	Annual MWh @ Input		6,248,604	599,673	652,997	1,995	459,186	708,531	1,038,290	22,801	184,262	1,167,972	82,702	492,415	122,047	884,743	1,436,937	2,002,659	253,620	21,832
6																						
7	Units	Customer	Average		513,581	70,880	15,103	50	4,630	3,683	2,286	59	200	606	41	82	59	4	25	8	3,311	7,437
8	Units	Customer	Annual - Metered		513,581	70,880	15,103	50	4,630	3,683	2,286	59	200	606	41	82	59	4	25	8	7,887	98
9																						
10																						
11	$/Unit	Demand	Generation ($/System Peak kW)		$ 149.62	$149.62	$149.62	$149.62	$149.62	$149.62	$149.62	$149.62	$149.62	$149.62	$149.62	$149.62	$149.62	$149.62	$149.62	$149.62	$149.62	$149.62
12	$/Unit	Demand	Transmission ($/System Peak kW)		$7.10	$7.10	$7.10	$7.10	$7.10	$7.10	$7.10	$7.10	$7.10	$7.10	$7.10	$7.10	$7.10	$7.10	$7.10	$7.10	$7.10	$0.00
13	$/Unit	Demand	Dist-Poles ($/Dist. kW)		$21.47	$32.01	$32.01	$32.01	$22.67	$22.67	$22.67	$22.67	$15.84	$15.37	$15.84	$30.76	$30.76	$0.00	$0.00	$0.00	$64.23	$32.01
14	$/Unit	Demand	Dist-Cond ($/Dist. kW)		$28.47	$37.20	$37.20	$37.20	$29.23	$29.23	$29.23	$29.23	$23.56	$23.11	$23.56	$35.60	$35.60	$0.00	$0.00	$0.00	$65.65	$37.20
15	$/Unit	Demand	Dist-Substation ($/Dist. kW)		$21.45	$21.45	$21.45	$21.45	$21.45	$21.45	$21.45	$21.45	$21.45	$21.45	$21.45	$21.45	$21.45	$21.45	$21.45	$21.45	$21.45	$0.00
16	$/Unit	Demand	Dist-Transformers ($/Xfmr kW)		$2.33	$2.33	$2.33	$0.00	$2.33	$2.33	$2.33	$0.00	$2.33	$2.33	$0.00	$2.33	$0.00	$2.33	$0.00	$0.00	$2.33	$2.33
17																						
18	$/Unit	Energy	Generation Energy @ Input ($/kWh)		$0.04477	$0.04477	$0.04477	$0.04477	$0.04477	$0.04477	$0.04477	$0.04477	$0.04477	$0.04477	$0.04477	$0.04477	$0.04477	$0.04477	$0.04477	$0.04477	$0.04477	$0.04477
19																						
20																						
21	$/Unit	Customer	Dist-Poles ($/Customer)		$94.23	$145.06	$145.06	$145.06	$99.51	$99.51	$99.51	$99.51	$66.50	$64.10	$66.50	$137.77	$137.77	$0.00	$0.00	$0.00	$304.28	$145.06
22	$/Unit	Customer	Dist-Conductor ($/Customer)		$40.96	$63.05	$63.05	$63.05	$43.25	$43.25	$43.25	$43.25	$28.90	$27.87	$28.90	$59.88	$59.88	$0.00	$0.00	$0.00	$132.24	$63.05
23	$/Unit	Customer	Dist-Transformers ($/Customer)		$122.51	$256.94	$323.32	$0.00	$887.22	$994.75	$1,083.62	$0.00	$1,286.48	$1,289.98	$0.00	$1,243.96	$0.00	$1,243.96	$0.00	$0.00	$1,051.07	$167.43
24	$/Unit	Customer	Dist-Service Drop ($/Customer)		$84.10	$114.88	$214.66	$0.00	$213.77	$218.49	$497.73	$0.00	$362.07	$903.85	$0.00	$3,265.83	$0.00	$3,265.83	$0.00	$0.00	$0.00	$0.00
25	$/Unit	Customer	Meters ($/Customer)		$24.91	$26.43	$30.00	$1,729.42	$33.37	$35.35	$206.86	$1,729.42	$207.21	$207.30	$1,729.42	$262.83	$1,729.42	$262.83	$1,729.42	$26,606.01	$33.45	$26.43
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	$0.00
27	$/Unit	Customer	Billing & Collections ($/Customer)		$25.10	$29.16	$29.16	$29.16	$33.83	$33.83	$33.83	$33.83	$33.83	$33.83	$33.83	$279.41	$279.41	$279.41	$279.41	$279.41	$29.14	$25.72
28	$/Unit	Customer	Uncollectables ($/Customer)		$11.60	$1.59	$1.59	$1.59	$16.70	$16.70	$16.70	$16.70	$108.13	$108.13	$108.13	$1,366.11	$1,366.11	$1,366.11	$1,366.11	$1,366.11	$20.91	$0.00
29	$/Unit	Customer	Customer Service / Other ($/Customer)		$10.69	$10.50	$10.50	$10.50	$11.26	$11.26	$11.26	$11.26	$14.74	$14.74	$14.74	$72.04	$72.04	$72.04	$72.04	$72.04	$11.24	$10.31
30																						
31																						
32	$000	Demand	Generation	$371,080	$165,688	$13,816	$14,841	$45	$10,541	$15,993	$22,874	$490	$4,063	$24,900	$1,712	$10,166	$11,250	$2,298	$32,695	$34,503	$5,065	$141
33	$000	Demand	Transmission	$17,603	$7,863	$656	$704	$2	$500	$759	$1,085	$23	$193	$1,182	$81	$482	$534	$109	$1,552	$1,637	$240	$0
34	$000	Demand	Dist-Poles	$53,771	$28,252	$3,137	$3,390	$10	$1,710	$2,564	$3,602	$76	$449	$2,630	$187	$2,125	$2,364	$0	$0	$0	$3,272	$3
35	$000	Demand	Dist-Conductor	$68,757	$37,460	$3,646	$3,939	$12	$2,205	$3,307	$4,646	$98	$668	$3,956	$278	$2,459	$2,736	$0	$0	$0	$3,344	$4
36	$000	Demand	Dist-Substations	$59,062	$28,220	$2,102	$2,271	$7	$1,618	$2,426	$3,408	$72	$608	$3,671	$254	$1,481	$1,648	$336	$4,773	$5,075	$1,093	$0
37	$000	Demand	Dist-Transformers	$15,726	$8,557	$1,849	$1,045	$0	$485	$988	$1,232	$0	$108	$627	$0	$267	$0	$66	$0	$0	$473	$28
38	$000	Demand	Total Demand	$585,998	$276,039	$25,206	$26,191	$76	$17,059	$26,036	$36,849	$759	$6,089	$36,964	$2,513	$16,980	$18,531	$2,809	$39,019	$41,216	$13,487	$176
39																						
40	$000	Energy	Generation	$733,380	$279,746	$26,847	$29,234	$89	$20,557	$31,721	$46,484	$1,021	$8,249	$52,289	$3,703	$22,045	$5,464	$39,609	$64,331	$89,658	$11,354	$977
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	$733,380	$279,746	$26,847	$29,234	$89	$20,557	$31,721	$46,484	$1,021	$8,249	$52,289	$3,703	$22,045	$5,464	$39,609	$64,331	$89,658	$11,354	$977
43																						
44	$000	Customer	Dist-Poles	$64,422	$48,393	$10,282	$2,191	$7	$461	$367	$227	$6	$13	$39	$3	$11	$8	$0	$0	$0	$2,400	$14
45	$000	Customer	Dist-Conductor	$28,001	$21,034	$4,469	$952	$3	$200	$159	$99	$3	$6	$17	$1	$5	$4	$0	$0	$0	$1,043	$6
46	$000	Customer	Dist-Transformers	$105,715	$62,918	$18,212	$4,883	$0	$4,108	$3,664	$2,477	$0	$258	$781	$0	$102	$0	$5	$0	$0	$8,290	$16
47	$000	Customer	Dist-Service Drop	$58,411	$43,193	$8,142	$3,242	$0	$990	$805	$1,138	$0	$72	$548	$0	$268	$0	$13	$0	$0	$0	$0
48	$000	Customer	Meters	$16,951	$12,794	$1,873	$453	$86	$155	$130	$473	$102	$41	$126	$71	$22	$103	$1	$43	$213	$264	$3
49	$000	Customer	Meter Reading	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
50	$000	Customer	Billing & Collections	$16,127	$12,891	$2,067	$440	$1	$157	$125	$77	$2	$7	$20	$1	$23	$17	$1	$7	$2	$96	$191
51	$000	Customer	Uncollectables	$6,677	$5,958	$113	$24	$0	$77	$62	$38	$1	$22	$65	$4	$112	$81	$6	$34	$11	$69	$0
52	$000	Customer	Customer Service / Other	$6,655	$5,492	$745	$159	$1	$52	$41	$26	$1	$3	$9	$1	$6	$4	$0	$2	$1	$37	$77
53	$000	Customer	Total Customer (Commitment & Billing)	$302,958	$212,673	$45,903	$12,344	$99	$6,199	$5,352	$4,555	$114	$422	$1,605	$81	$548	$216	$27	$85	$227	$12,200	$307
54																						
55																						
56			Total Revenue @ Full MC ($000)	$1,622,336	$768,459	$97,956	$67,770	$264	$43,816	$63,109	$87,888	$1,894	$14,761	$90,859	$6,296	$39,573	$24,211	$42,445	$103,434	$131,100	$37,041	$1,461

5 Year MC

PacifiCorp
Oregon Marginal Cost Study
5 Year Marginal Cost
December 2025 Dollars

					(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(Q)
					Residential	General Service - Schedule 23			General Service - Schedule 28				General Service - Schedule 30			Large Power Service - Schedule 48					Irrg - Sch 41	Streetlighting
	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)	(sec)
1	Units	Demand	Peak MW @ Input-System		1,107	92	99	0	70	107	153	3	27	166	11	68	75	15	219	231	34	0
2	Units	Energy	Annual MWh @ Input		6,248,604	599,673	652,997	1,995	459,186	708,531	1,038,290	22,801	184,262	1,167,972	82,702	492,415	122,047	884,743	1,436,937	2,002,659	253,620	21,832
3	Units	Customer	Average		513,581	70,880	15,103	50	4,630	3,683	2,286	59	200	606	41	82	4	59	25	8	3,311	7,437
4	Units	Customer	Annual		513,581	70,880	15,103	50	4,630	3,683	2,286	59	200	606	41	82	4	59	25	8	7,887	7,437
5	Units	Customer	Metered Lighting		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	98
6																						
7																						
8	$/Unit	Demand	Generation ($/System Peak kW)		$134.01	$134.01	$134.01	$134.01	$134.01	$134.01	$134.01	$134.01	$134.01	$134.01	$134.01	$134.01	$134.01	$134.01	$134.01	$134.01	$134.01	$134.01
9	$/Unit	Energy	Generation Energy @ Input ($/kWh)		$0.05403	$0.05403	$0.05403	$0.05403	$0.05403	$0.05403	$0.05403	$0.05403	$0.05403	$0.05403	$0.05403	$0.05403	$0.05403	$0.05403	$0.05403	$0.05403	$0.05403	$0.05403
10	$/Unit	Customer	Dist-Service Drop ($/Customer)		$84.10	$114.88	$214.66	$0.00	$213.77	$218.49	$497.73	$0.00	$521.42	$903.85	$0.00	$3,265.83	$0.00	$3,265.83	$0.00	$0.00	$0.00	$0.00
11	$/Unit	Customer	Meters ($/Customer)		$24.91	$26.43	$30.00	$1,729.42	$33.37	$35.35	$206.86	$1,729.42	$207.21	$207.30	$1,729.42	$262.83	$1,729.42	$262.83	$1,729.42	$26,606.01	$33.45	$26.43
12	$/Unit	Customer	Meter Reading ($/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	$0.00
13	$/Unit	Customer	Billing & Collections ($/Customer)		$25.10	$29.16	$29.16	$29.16	$33.83	$33.83	$33.83	$33.83	$33.83	$33.83	$33.83	$279.41	$279.41	$279.41	$279.41	$279.41	$29.14	$25.72
14	$/Unit	Customer	Uncollectables ($/Customer)		$11.60	$1.59	$1.59	$1.59	$16.70	$16.70	$16.70	$16.70	$108.13	$108.13	$108.13	$1,366.11	$1,366.11	$1,366.11	$1,366.11	$1,366.11	$20.91	$0.00
15	$/Unit	Customer	Customer Service / Other ($/Customer)		$10.69	$10.50	$10.50	$10.50	$11.26	$11.26	$11.26	$11.26	$14.74	$14.74	$14.74	$72.04	$72.04	$72.04	$72.04	$72.04	$11.24	$10.31
16																						
17																						
18	($000)	Demand	Total Demand	$332,261	$148,402	$12,375	$13,293	$40	$9,441	$14,324	$20,488	$439	$3,639	$22,302	$1,533	$9,105	$10,076	$2,059	$29,284	$30,904	$4,537	$20
19	($000)	Energy	Total Energy	$885,093	$337,617	$32,401	$35,282	$108	$24,810	$38,282	$56,100	$1,232	$9,956	$63,106	$4,468	$26,606	$6,594	$47,803	$77,639	$108,205	$13,703	$1,180
20	($000)	Customer	Total Customer (Billing)	$104,952	$80,328	$12,940	$4,318	$89	$1,430	$1,163	$1,752	$106	$177	$768	$77	$430	$14	$312	$85	$227	$467	$271
21			Total Revenue @ Full MC ($000)	$1,322,306	$566,347	$57,716	$52,893	$236	$35,681	$53,769	$78,339	$1,776	$13,772	$86,177	$6,079	$36,141	$16,685	$50,173	$107,007	$139,335	$18,707	$1,471

1 Year MC

PacifiCorp
Oregon Marginal Cost Study
1 Year Marginal Costs
December 2025 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	Streetlighting
	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)	(sec)
1	Units	Energy	Annual MWh @ Input		6,248,604	599,673	652,997	1,995	459,186	708,531	1,038,290	22,801	184,262	1,167,972	82,702	492,415	871,049	123,965	1,436,937	2,002,659	253,620	21,832
2	Units	Customer	Average		513,581	70,880	15,103	50	4,630	3,683	2,286	59	200	606	41	82	59	4	25	8	3,311	7,437
3	Units	Customer	Annual		513,581	70,880	15,103	50	4,630	3,683	2,286	59	200	606	41	82	59	4	25	8	7,887	7,437
4	Units	Customer	Metered Lighting		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	98
5																						
6																						
7	$/Unit	Energy	Generation Energy @ Input ($/kWh)		$0.08295	$0.08295	$0.08295	$0.08295	$0.08295	$0.08295	$0.08295	$0.08295	$0.08295	$0.08295	$0.08295	$0.08295	$0.08295	$0.08295	$0.08295	$0.08295	$0.08295	$0.08295
8	$/Unit	Customer	Dist-Service Drop ($/Customer)		$84.10	$114.88	$214.66	$0.00	$213.77	$218.49	$497.73	$0.00	$521.42	$903.85	$0.00	$3,265.83	$0.00	$3,265.83	$0.00	$0.00	$0.00	$0.00
9	$/Unit	Customer	Meters ($/Customer)		$24.91	$26.43	$30.00	$1,729.42	$33.37	$35.35	$143.00	$1,729.42	$207.21	$207.30	$1,729.42	$262.83	$1,729.42	$262.83	$1,729.42	$26,606.01	$33.45	$26.43
10	$/Unit	Customer	Meter Reading ($/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	$0.00
11	$/Unit	Customer	Billing & Collections ($/Customer)		$25.10	$29.16	$29.16	$29.16	$33.83	$33.83	$33.83	$33.83	$33.83	$33.83	$33.83	$279.41	$279.41	$279.41	$279.41	$279.41	$29.14	$25.72
12	$/Unit	Customer	Uncollectables ($/Customer)		$11.60	$1.59	$1.59	$1.59	$16.70	$16.70	$16.70	$16.70	$108.13	$108.13	$108.13	$1,366.11	$1,366.11	$1,366.11	$1,366.11	$1,366.11	$20.91	$0.00
13	$/Unit	Customer	Customer Service / Other ($/Customer)		$10.69	$10.50	$10.50	$10.50	$11.26	$11.26	$11.26	$11.26	$14.74	$14.74	$14.74	$72.04	$72.04	$72.04	$72.04	$72.04	$11.24	$10.31
14																						
15																						
16	($000)	Energy	Total Energy	$1,357,904	$518,343	$49,745	$54,168	$166	$38,091	$58,775	$86,130	$1,891	$15,285	$96,887	$6,860	$40,847	$72,256	$10,283	$119,199	$166,127	$21,039	$1,811
17	($000)	Customer	Total Customer (Billing)	$104,707	$80,328	$12,940	$4,318	$89	$1,430	$1,163	$1,606	$106	$177	$768	$77	$430	$205	$21	$85	$227	$467	$271
18			Total Revenue @ Full MC ($000)	$1,462,611	$598,671	$62,685	$58,487	$254	$39,521	$59,938	$87,735	$1,997	$15,462	$97,655	$6,938	$41,277	$72,461	$10,305	$119,284	$166,354	$21,505	$2,082

Generation

PacifiCorp
Oregon Marginal Cost Study
Marginal Generation Costs

Line	Lithium-Ion, 4-Hour, 1000MW[1]	
1	Total Capital Cost $/kW	$1,816.49
2	Payment Factor	5.557%
3	Total Capital Cost $/kW-Yr	$100.94
4	O&M cost per kW-Yr	43.12
5	Total Cost per kW-Yr	$144.06
6	Capacity Contribution[2]	77%
7	Capacity Cost $/kW-Yr	$187.77

Line		**Flat Market Price (MidC Hub)[3]**	**Energy Benefit of Storage**
8	2025	94.91	83.03
9	2026	79.81	84.92
10	2027	59.47	53.33
11	2028	54.69	24.26
12	2029	55.12	28.57
13	2030	56.40	25.92
14	2031	56.99	26.60
15	2032	55.36	16.12
16	2033	47.28	17.65
17	2034	48.89	18.77
18	2035	49.70	19.81
19	2036	51.27	18.93
20	2037	54.44	18.91
21	2038	57.74	22.18
22	2039	58.76	22.06
23	2040	62.06	27.23
24	2041	63.08	44.68
25	2042	64.76	42.84
26	2043	66.23	43.81
27	2044	67.73	44.80

Marginal Costs

Line		Energy Benefit of Storage $/kW-Yr	**Net Capacity Cost $/kW-Yr**	Cost per MWh	Capacity Contribution of Energy	Capacity Credit	**Cost per MWh**
28	1 Year	(83.03)	**$104.74**	94.91	100%	-$11.96	**$82.95**
29	5 Years	(53.77)	**$134.01**	65.99	100%	-$15.30	**$54.03**
30	10 Years	(38.16)	**$149.62**	56.73	100%	-$17.08	**$44.77**
31	20 Years	(31.49)	**$156.28**	51.11	100%	-$17.84	**$39.16**

[1]2023 Intergrated Resource Plan Volume I
[2]PacifiCorp's 2021 Integrated Resource Plan Volume II, Appendix K
[3]PacifiCorps's March 2023 Official Forward Price Curve in the Avoided Cost Study effective September 2023

Transm

PacifiCorp
Oregon Marginal Cost Study
Marginal Transmission Investment and O&M Expenses
2025 Dollars (000s)

		Forecast Transmission					
Line	Description	2024	2025	2026	2027	2028	2024-2028
1	Bulk Power Lines (grid)	$0	$0	$0	$0	$0	$0
2	Growth Related Major Projects (local)	$9,279	$32,815	$83,834	$93,000	$40,273	$259,200
3							
4	Adjusted Bulk Power Lines (grid)	$0	$0	$0	$0	$0	$0
5	Adjusted Growth Related Major Projects (local)	$9,705	$34,321	$87,683	$97,270	$42,122	$271,102
6							
	Total Growth Related Investments - Demand	$9,705	$34,321	$87,683	$97,270	$42,122	$271,101
	Total Growth Related Investments - Energy	$0	$0	$0	$0	$0	$0
	Total Marginal Transmission Investment	$9,705	$34,321	$87,683	$97,270	$42,122	$271,101

Description	Total	Demand Related	Energy Related
Marginal Investment ($/KW)	$84.43	$84.43	$0.00
Annualized Investment ($/KW)	$5.70	$5.70	$0.00
Admin. & General Factor ($/KW)	$0.49	$0.49	$0.00
Annual O&M Expenses ($/KW)	$0.91	$0.91	$0.00
Annualized Marginal Cost ($/KW)	$7.10	$7.10	$0.00
Marginal Cost of Energy-Related Transmission ($/KWh)			$0.00

Escalation Factor
2023-2025
1.0459

Footnotes:

Bulk power line & growth related projects data provided in 2023 dollars for each year

Demand Portion of Transmission = PV of Long Run Capacity Costs / PV of Total Long Run Costs = 156.28 / (156.28+39.16) = 79.96%

Energy Portion of Transmission = PV of Long Run Energy Costs / PV of Total Long Run Costs = 39.16 / (156.28+39.16) = 20.04%

Capacity Addition MW from 2024-2028 = 3,211

TransOM

PacifiCorp
Transmission O & M Expenses
(Dollars in 000's)

Line	Description	Calculation	(A) 2013	(B) 2014	(C) 2015	(D) 2016	(E) 2017	(F) 2018	(G) 2019	(H) 2020	(I) 2021	(J) 2022	(K) =AVERAGE of (A) thru (J)
1	Transmission O&M Exp.		198,670	211,984	215,664	203,261	204,806	206,506	218,367	210,892	232,302	239,534	
2	Wheeling		137,182	151,336	148,425	130,789	134,473	135,022	145,825	141,188	159,058	163,235	
3	Net Transmission O&M	1-2	61,488	60,648	67,239	72,472	70,333	71,484	72,541	69,703	73,243	76,299	
4	Transmission Plant		5,231,106	5,387,871	5,910,756	6,051,720	6,222,286	6,353,045	6,478,620	7,630,241	7,892,551	8,048,836	
5	Tran. O&M Loading	3/4	1.175%	1.126%	1.138%	1.198%	1.130%	1.125%	1.120%	0.914%	0.928%	0.948%	1.080%

Source:
PacifiCorp FERC Form 1
(1) page 321, line 112
(2) page 321, line 96
(4) page 206-07, line 58

TransLF

PacifiCorp
System Load Factor

Line No.	Month	Total Monthly Energy	Associated Losses		MW
	(A)	(B)	(C)	(D) (B)-(C)	(E)
1	January	5,930,733	495,061	5,435,672	8,514
2	February	5,316,777	456,082	4,860,695	8,805
3	March	5,393,979	539,851	4,854,128	8,249
4	April	4,994,632	424,178	4,570,454	7,819
5	May	5,002,715	304,332	4,698,383	8,135
6	June	5,470,102	583,233	4,886,869	10,216
7	July	6,444,768	259,229	6,185,539	11,017
8	August	6,252,889	267,669	5,985,220	10,623
9	September	5,311,089	312,697	4,998,392	10,593
10	October	4,979,242	311,904	4,667,338	7,476
11	November	5,382,263	258,567	5,123,696	8,447
12	December	6,008,903	350,219	5,658,684	9,026
13		66,488,092	4,563,022	61,925,070	
14					
15				Average Monthly MW	9,077
16				Load Factor	77.88%

Source: FERC Form 1, December 31, 2022
Page 401b

DistSub

PacifiCorp
Oregon Marginal Cost Study
Distribution Substation Costs / kW
2023 Dollars

Line	Description	Calculation	Value
1	Incremental Substation Cost ($/kVA)		$366.57
2	Power Factor		0.95
3	Installed Capacity (MVA)		5172
4	Installed Capacity (MW)		4914
5	Distribution Peak Load		2553
6	Substation Utilization Factor		51.95%
7	Incremental Substation Cost ($/kW)	1/2*3	$200.45
8			
9	Annual Distribution Carrying Charge		7.43%
10			
11	Substation Marginal Cost ($/kW)	4*6	$14.89

Substation Investment

(A) In Service Year	(B) Substation Capacity Project	(C) State	(D) Capacity Increase (MVA)	(E) Installed Cost (000)	(F) =(E)/(D) Installed Cost/MVA (000)
2024	Medford	OR	25.0	$3,100	$124.02
2025	Teiton	WA	25.0	$5,073	$202.93
2025	Bond	OR	25.0	$7,221	$288.85
2025	Rickreall	OR	30.0	$9,376	$312.54
2026	Mill City	OR	25.0	$9,065	$362.62
2026	Fort Jones	CA	7.0	$2,712	$387.41
2026	Banfield	OR	25.0	$9,909	$396.35
2026	China Hat	OR	25.0	$6,821	$272.85
2026	Ahtanum	WA	25.0	$9,285	$371.41
2027	Culver Sub	OR	12.5	$5,165	$413.21
2027	Empire and State	OR	25.0	$7,699	$307.97
2027	Glendale	OR	12.5	$3,596	$287.65
2027	Overpass	OR	13.0	$7,879	$606.07
2027	Redmond	OR	25.0	$11,226	$449.05
2027	Sulphur Creek	WA	30.0	$8,331	$277.69
2027	Wake Robin	OR	30.0	$19,686	$656.20
2027	Whetstone	OR	30.0	$10,300	$343.33
2027	Lebanon	OR	10.0	$6,028	$602.81
2028	Tangent Area	OR	30.0	$10,274	$342.46
2028	Walla Walla	WA	30.0	$8,470	$282.34
		Western States Total	460.0	$161,218	$350.47

Escalation Factor
2023-2025
1.0459

Incremental Substation Cost ($/KVA) $350.47

PC1

PacifiCorp
Oregon Marginal Cost Study
Calculation of Escalation Factors
Poles and Conductor
Hypothetical Circuit Study Results Annual Demand and Commitment Costs

Line	Load Class		Demand						Commitment					
					Investment $ / kW[1]		Annual $ / kW[1]				Investment $ / Customer		Annual $ / Customer	
			Poles	Conductor	Poles	Conductor	Poles	Conductor	Poles	Conductor	Poles	Conductor	Poles	Conductor
1	Res - Schedule 4	(sec)	$ 191.87	$ 254.38	$ 200.68	$ 266.06	$ 14.91	$ 19.77	$ 841.90	$ 365.91	$ 880.56	$ 382.71	$ 65.43	$ 28.44
2														
3	GS - Schedule 23													
4	0-15 kW	(sec)	$ 286.09	$ 332.38	$ 299.22	$ 347.65	$ 22.23	$ 25.83	$ 1,296.15	$ 563.34	$ 1,355.66	$ 589.20	$ 100.73	$ 43.78
5	15+ kW	(sec)	$ 286.09	$ 332.38	$ 299.22	$ 347.65	$ 22.23	$ 25.83	$ 1,296.15	$ 563.34	$ 1,355.66	$ 589.20	$ 100.73	$ 43.78
6	Primary	(pri)	$ 286.09	$ 332.38	$ 299.22	$ 347.65	$ 22.23	$ 25.83	$ 1,296.15	$ 563.34	$ 1,355.66	$ 589.20	$ 100.73	$ 43.78
7														
8	GS - Schedule 28													
9	0-50 kW	(sec)	$ 202.58	$ 261.28	$ 211.88	$ 273.27	$ 15.74	$ 20.30	$ 889.19	$ 386.46	$ 930.01	$ 404.21	$ 69.10	$ 30.03
10	51-100 kW	(sec)	$ 202.58	$ 261.28	$ 211.88	$ 273.27	$ 15.74	$ 20.30	$ 889.19	$ 386.46	$ 930.01	$ 404.21	$ 69.10	$ 30.03
11	100 + kW	(sec)	$ 202.58	$ 261.28	$ 211.88	$ 273.27	$ 15.74	$ 20.30	$ 889.19	$ 386.46	$ 930.01	$ 404.21	$ 69.10	$ 30.03
12	Primary	(pri)	$ 202.58	$ 261.28	$ 211.88	$ 273.27	$ 15.74	$ 20.30	$ 889.19	$ 386.46	$ 930.01	$ 404.21	$ 69.10	$ 30.03
13														
14	GS - Schedule 30													
15	0-300 kW	(sec)	$ 141.52	$ 210.47	$ 148.02	$ 220.13	$ 11.00	$ 16.36	$ 594.22	$ 258.26	$ 621.50	$ 270.12	$ 46.18	$ 20.07
16	300+ kW	(sec)	$ 137.30	$ 206.49	$ 143.60	$ 215.97	$ 10.67	$ 16.05	$ 572.81	$ 248.96	$ 599.11	$ 260.39	$ 44.51	$ 19.35
17	Primary	(pri)	$ 141.52	$ 210.47	$ 148.02	$ 220.13	$ 11.00	$ 16.36	$ 594.22	$ 258.26	$ 621.50	$ 270.12	$ 46.18	$ 20.07
18														
19	LPS - Schedule 48													
20	1 - 4 MW	(sec)	$ 274.88	$ 318.09	$ 287.50	$ 332.70	$ 21.36	$ 24.72	$ 1,231.08	$ 535.06	$ 1,287.60	$ 559.62	$ 95.67	$ 41.58
21	1 - 4 MW	(pri)	$ 274.88	$ 318.09	$ 287.50	$ 332.70	$ 21.36	$ 24.72	$ 1,231.08	$ 535.06	$ 1,287.60	$ 559.62	$ 95.67	$ 41.58
22	> 4 MW	(sec)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23	> 4 MW	(pri)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
24														
25	Irrigation - Schedule 41	(sec)	$ 573.90	$ 586.62	$ 600.25	$ 613.55	$ 44.60	$ 45.59	$ 2,718.91	$ 1,181.70	$ 2,843.75	$ 1,235.96	$ 211.29	$ 91.83

Escalation Factor
2023-2025
1.0459

PC 2

PacifiCorp
Oregon Marginal Cost Study
Circuit Distribution Model
Inputs & Calculations

Line	Class	(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)	5,814,272	533,013	10.91	1,213.04	2.28	100.00%
6	GS - Schedule 23 - 0-15 kW (sec)	586,948	71,109	8.25	90.35	1.27	80.77%
7	GS - Schedule 23 - 15+ kW (sec)	639,141	15,152	42.18	97.63	6.44	54.22%
8	GS - Schedule 23 - Primary (pri)	1,955	50	38.86	0.30	5.87	0.62%
9	GS - Schedule 28 - 0-50 kW (sec)	434,116	4,543	95.57	69.55	15.31	29.27%
10	GS - Schedule 28 - 51-100 kW (sec)	669,847	3,614	185.36	104.28	28.86	14.60%
11	GS - Schedule 28 - 100 + kW (sec)	981,603	2,243	437.7	146.51	65.33	2.48%
12	GS - Schedule 28 - Primary (pri)	21,809	59	372.57	3.13	53.40	(0.79%)
13	GS - Schedule 30 - 0-300 kW (sec)	170,220	198	857.81	26.14	131.75	0.42%
14	GS - Schedule 30 - 300+ kW (sec)	1,078,967	600	1797.27	157.78	262.82	0.06%
15	GS - Schedule 30 - Primary (pri)	76,532	40	1893.06	11.04	273.15	1.06%
16	Irrigation - Sch 41	196,326	6,149	31.93	46.96	7.64	15.70%
17	LPS - Schedule 48 - 1 - 4 MW (sec)	456,583	81	5670.86	63.68	790.87	0.15%
18	LPS - Schedule 48 - 1 - 4 MW (pri)	509,238	58	8766.52	71.79	1,235.87	0.41%
19	LPS - Schedule 48 - > 4 MW (sec)	114,945	4	28616.96	14.42	3,590.54	0.37%
20	LPS - Schedule 48 - > 4 MW (pri)	840,070	24	34873.74	207.89	8,630.13	(1.08%)
21	Total	12,592,571	636,937		2,324.50		
22							
23							

24 Customer Distribution on the Hypothetical Circuit Branch

Line	Class	(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)	0.37%	0.37%	0.37%	1.81%	1.81%	1.81%	93.46%	100.00%
29	GS - Schedule 23 - 0-15 kW (sec)	0.69%	0.69%	0.69%	2.57%	2.57%	2.57%	90.19%	100.00%
30	GS - Schedule 23 - 15+ kW (sec)	0.69%	0.69%	0.69%	2.57%	2.57%	2.57%	90.19%	100.00%
31	GS - Schedule 23 - Primary (pri)	0.69%	0.69%	0.69%	2.57%	2.57%	2.57%	90.19%	100.00%
32	GS - Schedule 28 - 0-50 kW (sec)	0.48%	0.48%	0.48%	1.52%	1.52%	1.52%	94.00%	100.00%
33	GS - Schedule 28 - 51-100 kW (sec)	0.48%	0.48%	0.48%	1.52%	1.52%	1.52%	94.00%	100.00%
34	GS - Schedule 28 - 100 + kW (sec)	0.48%	0.48%	0.48%	1.52%	1.52%	1.52%	94.00%	100.00%
35	GS - Schedule 28 - Primary (pri)	0.48%	0.48%	0.48%	1.52%	1.52%	1.52%	94.00%	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%	0.85%	0.85%	0.85%	96.61%	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	1.08%	1.08%	1.08%	7.97%	7.97%	7.97%	72.85%	100.00%
40	LPS - Schedule 48 - 1 - 4 MW (sec)	0.85%	0.85%	0.85%	1.52%	1.52%	1.52%	92.89%	100.00%
41	LPS - Schedule 48 - 1 - 4 MW (pri)	0.85%	0.85%	0.85%	1.52%	1.52%	1.52%	92.89%	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		
46	System property records & engineering information	
47	Number of pole feet in Oregon	75,736,758
48	Number of pole miles in Oregon	14,344
49	Number of trench feet in Oregon	29,644,711
50	Number of trench miles in Oregon	5,615
51	Total miles in Oregon	19,959
52	Number of circuits in Oregon	530
53	Number of poles in Oregon	380,944
54	Poles per mile	26.56
55	Customers per mile	31.91
56	MWh per customer	19.77
57	MWh per circuit	23,760
58	Branches per circuit	7
59	Miles per circuit	37.66
60	Miles per branch	5.38
61	Single Phase Miles per Branch[1]	1.88
62	Average Trunk Length	0.67

[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 3

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)	3.71	3.71	3.71	18.21	18.21	18.21	939.93	1,005.68
4	GS - Schedule 23 - 0-15 kW (sec)	0.93	0.93	0.93	3.45	3.45	3.45	121.01	134.17
5	GS - Schedule 23 - 15+ kW (sec)	0.20	0.20	0.20	0.74	0.74	0.74	25.79	28.59
6	GS - Schedule 23 - Primary (pri)	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.09
7	GS - Schedule 28 - 0-50 kW (sec)	0.04	0.04	0.04	0.13	0.13	0.13	8.06	8.57
8	GS - Schedule 28 - 51-100 kW (sec)	0.03	0.03	0.03	0.10	0.10	0.10	6.41	6.82
9	GS - Schedule 28 - 100 + kW (sec)	0.02	0.02	0.02	0.06	0.06	0.06	3.98	4.23
10	GS - Schedule 28 - Primary (pri)	0.00	0.00	0.00	0.00	0.00	0.00	0.10	0.11
11	GS - Schedule 30 - 0-300 kW (sec)	0.00	0.00	0.00	0.00	0.00	0.00	0.36	0.37
12	GS - Schedule 30 - 300+ kW (sec)	0.00	0.00	0.00	0.01	0.01	0.01	1.09	1.13
13	GS - Schedule 30 - Primary (pri)	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.08
14	Irrigation - Sch 41	0.13	0.13	0.13	0.92	0.92	0.92	8.45	11.60
15	LPS - Schedule 48 - 1 - 4 MW (sec)	0.00	0.00	0.00	0.00	0.00	0.00	0.14	0.15
16	LPS - Schedule 48 - 1 - 4 MW (pri)	0.00	0.00	0.00	0.00	0.00	0.00	0.10	0.11
17	LPS - Schedule 48 - > 4 MW (sec)	-	-	-	-	-	-	-	-
18	LPS - Schedule 48 - > 4 MW (pri)	-	-	-	-	-	-	-	-
19	Total	5.06	5.06	5.06	23.65	23.65	23.65	1,115.58	1,201.72
20									
21	Source - 'Circuit Distribution Model Inputs & Calculations' (PC 2)								
22	Source - 'Customer Distribution on the Hypothetical Circuit Branch' (PC 2)								
23	Customers multiplied by Customer Distribution on the Hypothetical Circuit Branch divided by circuits in the state.								
24	For Example 3.71 is 533,013 Residential Customers X .368% customers on Branch 1 divided by 530 circuits.								
25									

26	Percent of Customers								
27	Res - Schedule 4 (sec)	73.18%	73.18%	73.18%	77.02%	77.02%	77.02%	84.25%	83.69%
28	GS - Schedule 23 - 0-15 kW (sec)	18.40%	18.40%	18.40%	14.61%	14.61%	14.61%	10.85%	11.16%
29	GS - Schedule 23 - 15+ kW (sec)	3.92%	3.92%	3.92%	3.11%	3.11%	3.11%	2.31%	2.38%
30	GS - Schedule 23 - Primary (pri)	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
31	GS - Schedule 28 - 0-50 kW (sec)	0.81%	0.81%	0.81%	0.55%	0.55%	0.55%	0.72%	0.71%
32	GS - Schedule 28 - 51-100 kW (sec)	0.65%	0.65%	0.65%	0.44%	0.44%	0.44%	0.57%	0.57%
33	GS - Schedule 28 - 100 + kW (sec)	0.40%	0.40%	0.40%	0.27%	0.27%	0.27%	0.36%	0.35%
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%	0.03%	0.03%
36	GS - Schedule 30 - 300+ kW (sec)	0.06%	0.06%	0.06%	0.04%	0.04%	0.04%	0.10%	0.09%
37	GS - Schedule 30 - Primary (pri)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.01%
38	Irrigation - Sch 41	2.48%	2.48%	2.48%	3.91%	3.91%	3.91%	0.76%	0.97%
39	LPS - Schedule 48 - 1 - 4 MW (sec)	0.03%	0.03%	0.03%	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)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
42	LPS - Schedule 48 - > 4 MW (pri)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
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	5.06	5.06	5.06			23.65		38.84
47	1,2,3,4,5,6,7	5.06	5.06	5.06	23.65	23.65	23.65	1,115.58	1,201.72
48									
49	1,2,3,6	13.0%	13.0%	13.0%	0.0%	0.0%	60.9%	0.0%	100.0%
50	1,2,3,4,5,6,7	0.4%	0.4%	0.4%	2.0%	2.0%	2.0%	92.8%	100.0%

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)	8.43	8.43	8.43	41.45	41.45	41.45	2,139.10	2,288.76
4	GS - Schedule 23 - 0-15 kW (sec)	1.18	1.18	1.18	4.39	4.39	4.39	153.76	170.48
5	GS - Schedule 23 - 15+ kW (sec)	1.28	1.28	1.28	4.74	4.74	4.74	166.14	184.21
6	GS - Schedule 23 - Primary (pri)	0.00	0.00	0.00	0.01	0.01	0.01	0.50	0.56
7	GS - Schedule 28 - 0-50 kW (sec)	0.63	0.63	0.63	1.99	1.99	1.99	123.35	131.23
8	GS - Schedule 28 - 51-100 kW (sec)	0.95	0.95	0.95	2.99	2.99	2.99	184.95	196.76
9	GS - Schedule 28 - 100 + kW (sec)	1.33	1.33	1.33	4.20	4.20	4.20	259.85	276.44
10	GS - Schedule 28 - Primary (pri)	0.03	0.03	0.03	0.09	0.09	0.09	5.54	5.90
11	GS - Schedule 30 - 0-300 kW (sec)	0.14	0.14	0.14	0.48	0.48	0.48	47.47	49.33
12	GS - Schedule 30 - 300+ kW (sec)	0.84	0.84	0.84	2.53	2.53	2.53	287.59	297.70
13	GS - Schedule 30 - Primary (pri)	0.06	0.06	0.06	0.20	0.20	0.20	20.05	20.84
14	Irrigation - Sch 41	0.96	0.96	0.96	7.06	7.06	7.06	64.56	88.61
15	LPS - Schedule 48 - 1 - 4 MW (sec)	1.02	1.02	1.02	1.83	1.83	1.83	111.61	120.14
16	LPS - Schedule 48 - 1 - 4 MW (pri)	1.15	1.15	1.15	2.06	2.06	2.06	125.83	135.45
17	LPS - Schedule 48 - > 4 MW (sec)	-	-	-	-	-	-	-	-
18	LPS - Schedule 48 - > 4 MW (pri)	-	-	-	-	-	-	-	-
19	Total	17.99	17.99	17.99	74.03	74.03	74.03	3,690.31	3,966.39
20									
21	Source - 'Circuit Distribution Model Inputs & Calculations' (PC 2)								
22	Source - 'Average Customers by Hypothetical Circuit Branch' (PC 3)								
23	Customers multiplied by circuit kW per customer.								
24	For Example 8.4 is 3.71 Residential Customers multiplied by 2.28 average Dist. kW per Customer.								

25									
26	Percent of Branch Load								
27	Res - Schedule 4 (sec)	46.87%	46.87%	46.87%	55.99%	55.99%	55.99%	57.97%	57.70%
28	GS - Schedule 23 - 0-15 kW (sec)	6.58%	6.58%	6.58%	5.93%	5.93%	5.93%	4.17%	4.30%
29	GS - Schedule 23 - 15+ kW (sec)	7.11%	7.11%	7.11%	6.41%	6.41%	6.41%	4.50%	4.64%
30	GS - Schedule 23 - Primary (pri)	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.01%	0.01%
31	GS - Schedule 28 - 0-50 kW (sec)	3.50%	3.50%	3.50%	2.69%	2.69%	2.69%	3.34%	3.31%
32	GS - Schedule 28 - 51-100 kW (sec)	5.25%	5.25%	5.25%	4.04%	4.04%	4.04%	5.01%	4.96%
33	GS - Schedule 28 - 100 + kW (sec)	7.38%	7.38%	7.38%	5.68%	5.68%	5.68%	7.04%	6.97%
34	GS - Schedule 28 - Primary (pri)	0.16%	0.16%	0.16%	0.12%	0.12%	0.12%	0.15%	0.15%
35	GS - Schedule 30 - 0-300 kW (sec)	0.76%	0.76%	0.76%	0.65%	0.65%	0.65%	1.29%	1.24%
36	GS - Schedule 30 - 300+ kW (sec)	4.68%	4.68%	4.68%	3.41%	3.41%	3.41%	7.79%	7.51%
37	GS - Schedule 30 - Primary (pri)	0.32%	0.32%	0.32%	0.27%	0.27%	0.27%	0.54%	0.53%
38	Irrigation - Sch 41	5.33%	5.33%	5.33%	9.53%	9.53%	9.53%	1.75%	2.23%
39	LPS - Schedule 48 - 1 - 4 MW (sec)	5.65%	5.65%	5.65%	2.47%	2.47%	2.47%	3.02%	3.03%
40	LPS - Schedule 48 - 1 - 4 MW (pri)	6.37%	6.37%	6.37%	2.79%	2.79%	2.79%	3.41%	3.42%
41	LPS - Schedule 48 - > 4 MW (sec)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
42	LPS - Schedule 48 - > 4 MW (pri)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
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	17.99	17.99	17.99			74.03		128.01
47	1,2,3,4,5,6,7	17.99	17.99	17.99	74.03	74.03	74.03	3,690.31	3,966.39
48									
49	1,2,3,6	14.06%	14.06%	14.06%			57.83%		100.00%
50	1,2,3,4,5,6,7	0.45%	0.45%	0.45%	1.87%	1.87%	1.87%	93.04%	100.00%

PC 4

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	55,683	12,642,710	2,394	23.26	0.865
Idaho	97,904	21,437,890	4,060	24.11	0.897
Oregon	380,944	75,736,758	14,344	26.56	0.988
Utah	351,303	60,938,569	11,541	30.44	1.132
Washington	100,586	16,791,482	3,180	31.63	1.176
Wyoming	159,614	37,458,548	7,094	22.50	0.837
Total	1,146,034	225,005,957	42,615	26.89	1.000

	Account 364 Pole Cost per Mile			Account 365	Total Line
Wire Size	Pole Cost per Mile	Adjustment Factor	Adjusted Pole Cost	Conductor Cost per Mile	Construction Cost
1 1 Phase - 1/0 ACSR	$29,797	0.988	$29,425	$12,789	$42,214
2 3 Phase - 1/0 ACSR	$56,836	0.988	$56,127	$28,548	$84,675
3 - 447 AAC & 4\0 AAC	$63,338	0.988	$62,548	$62,952	$125,500
4 -795 AAC & 477 AAC	$65,804	0.988	$64,984	$110,173	$175,157

	Costs for Branches 1,2,3,4,5		
	1 Phase - 1/0 ACSR	3 Phase - 1/0 ACSR	Total
Poles	$55,405	$196,266	$251,670
Conductors	$24,080	$99,826	$123,907
Total	$79,485	$296,092	$375,577

	Costs for Branch 6	Cost for Branch 7
	3 Phase - 447 AAC & 4\0 AAC	3 Phase -795 AAC & 477 AAC
Poles	$336,490	$349,591
Conductors	$338,662	$592,695
Total	$675,151	$942,286

Miles per Branch	5.38
Single Phase Miles Per Branch	1.88
Three Phase Miles Per Branch	3.50

Commitment and Demand Costs Per Branch

	Poles			Conductor			
	Total Cost	Commitment	Demand	Total Cost	Commitment	Demand	Total
Branches 1,2,3,4,5							
1 Phase - 1/0 ACSR	$55,405	$55,405	$0	$24,080	$24,080	$0	$79,485
3 Phase - 1/0 ACSR	$196,266	$102,895	$93,371	$99,826	$44,720	$55,106	$296,092
Total Branches 1,2,3,4,5	$251,670	$158,300	$93,371	$123,907	$68,801	$55,106	$375,577
Branch 6							$0
3 Phase - 447 AAC & 4\0 AAC	$336,490	$158,300	$178,190	$338,662	$68,801	$269,861	$675,151
Branch 7							$0
3 Phase -795 AAC & 477 AAC	$349,591	$158,300	$191,291	$592,695	$68,801	$523,895	$942,286
Total All Branches	$1,944,433	$1,108,097	$836,335	$1,550,890	$481,605	$1,069,285	$3,495,323

Branch pole and conductor commitment costs equals single or three Phase Miles Per Branch Multiplied by 1 Phase - 1/0 ACSR Cost

PC 5

PacifiCorp
Oregon Circuit Model Study
Demand Calculations

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
		Poles								
Line		1	2	3	4	5	6	7	Total	
1	% customer	14.06%	14.06%	14.06%			57.83%		100.00%	
2	Branch 6 Cost	$ 25,045	$ 25,045	$ 25,045			$ 103,055		$ 178,190	$ / kW
3	% customer	0.45%	0.45%	0.45%	1.87%	1.87%	1.87%	93.04%	100.00%	
4	Branch 7 Cost	$ 868	$ 868	$ 868	$ 3,571	$ 3,571	$ 3,571	$ 177,976	$ 191,291	
5	Branch Commitment Cost	$ 93,371	$ 93,371	$ 93,371	$ 93,371	$ 93,371				Average
6	Total	$ 119,284	$ 119,284	$ 119,284	$ 96,941	$ 96,941	$ 106,625	$ 177,976	$ 836,335	$ 210.86
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)	$ 55,912	$ 55,912	$ 55,912	$ 54,276	$ 54,276	$ 59,698	$ 103,165	$ 439,152	$ 191.87
12	GS - Schedule 23 - 0-15 kW (sec)	$ 7,847	$ 7,847	$ 7,847	$ 5,747	$ 5,747	$ 6,321	$ 7,416	$ 48,771	$ 286.09
13	GS - Schedule 23 - 15+ kW (sec)	$ 8,479	$ 8,479	$ 8,479	$ 6,210	$ 6,210	$ 6,830	$ 8,013	$ 52,700	$ 286.09
14	GS - Schedule 23 - Primary (pri)	$ 26	$ 26	$ 26	$ 19	$ 19	$ 21	$ 24	$ 159	$ 286.09
15	GS - Schedule 28 - 0-50 kW (sec)	$ 4,180	$ 4,180	$ 4,180	$ 2,612	$ 2,612	$ 2,873	$ 5,949	$ 26,584	$ 202.58
16	GS - Schedule 28 - 51-100 kW (sec)	$ 6,267	$ 6,267	$ 6,267	$ 3,916	$ 3,916	$ 4,307	$ 8,920	$ 39,859	$ 202.58
17	GS - Schedule 28 - 100 + kW (sec)	$ 8,805	$ 8,805	$ 8,805	$ 5,502	$ 5,502	$ 6,051	$ 12,532	$ 56,002	$ 202.58
18	GS - Schedule 28 - Primary (pri)	$ 188	$ 188	$ 188	$ 117	$ 117	$ 129	$ 267	$ 1,195	$ 202.58
19	GS - Schedule 30 - 0-300 kW (sec)	$ 912	$ 912	$ 912	$ 631	$ 631	$ 694	$ 2,289	$ 6,981	$ 141.52
20	GS - Schedule 30 - 300+ kW (sec)	$ 5,583	$ 5,583	$ 5,583	$ 3,308	$ 3,308	$ 3,639	$ 13,870	$ 40,874	$ 137.30
21	GS - Schedule 30 - Primary (pri)	$ 385	$ 385	$ 385	$ 266	$ 266	$ 293	$ 967	$ 2,949	$ 141.52
22	Irrigation - Sch 41	$ 6,363	$ 6,363	$ 6,363	$ 9,242	$ 9,242	$ 10,165	$ 3,113	$ 50,853	$ 573.90
23	LPS - Schedule 48 - 1 - 4 MW (sec)	$ 6,739	$ 6,739	$ 6,739	$ 2,396	$ 2,396	$ 2,635	$ 5,383	$ 33,025	$ 274.88
24	LPS - Schedule 48 - 1 - 4 MW (pri)	$ 7,597	$ 7,597	$ 7,597	$ 2,701	$ 2,701	$ 2,971	$ 6,068	$ 37,233	$ 274.88
25	LPS - Schedule 48 - > 4 MW (sec)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	LPS - Schedule 48 - > 4 MW (pri)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Check Total	$ 119,284	$ 119,284	$ 119,284	$ 96,941	$ 96,941	$ 106,625	$ 177,976	$ 836,335	

Sources: Line 1 & 3 - 'Circuit kW Load by Branch' (PC 3)
Line 2 - 'Calculation of Hypothetical Circuit Model Branch Cost' (PC 4) for178,190
Line 1 X 178,190
Line 4 - 'Calculation of Hypothetical Circuit Model Branch Cost' (PC 4) for191,291
Line 3 X 191,291
Line 5 - 'Calculation of Hypothetical Circuit Model Branch Cost' (PC 4)
Line 7 to 18 - Line 6 X Percent of Branch Load 'Circuit kW Load by Branch' (PC 3)

PacifiCorp
Oregon Circuit Model Study
Demand Calculations

(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
Conductors								
1	2	3	4	5	6	7	Total	
14.06%	14.06%	14.06%			57.83%		100.00%	
$ 37,929.76	$ 37,929.76	$ 37,929.76	$ -	$ -	$ 156,071.59	$ -	$ 269,861	$ / kW
0.45%	0.45%	0.45%	1.87%	1.87%	1.87%	93.04%	100.00%	
$ 2,377	$ 2,377	$ 2,377	$ 9,779	$ 9,779	$ 9,779	$ 487,429	$ 523,895	
$ 55,106	$ 55,106	$ 55,106	$ 55,106	$ 55,106				Average
$ 95,412	$ 95,412	$ 95,412	$ 64,885	$ 64,885	$ 165,850	$ 487,429	$ 1,069,285	$ 269.59

1	2	3	4	5	6	7	Total Demand Cost	$ Per kW
$ 44,723	$ 44,723	$ 44,723	$ 36,328	$ 36,328	$ 92,857	$ 282,540	$ 582,222	$ 254.38
$ 6,277	$ 6,277	$ 6,277	$ 3,846	$ 3,846	$ 9,832	$ 20,309	$ 56,664	$ 332.38
$ 6,782	$ 6,782	$ 6,782	$ 4,156	$ 4,156	$ 10,623	$ 21,945	$ 61,228	$ 332.38
$ 20	$ 20	$ 20	$ 13	$ 13	$ 32	$ 66	$ 185	$ 332.38
$ 3,343	$ 3,343	$ 3,343	$ 1,748	$ 1,748	$ 4,468	$ 16,293	$ 34,287	$ 261.28
$ 5,013	$ 5,013	$ 5,013	$ 2,621	$ 2,621	$ 6,699	$ 24,429	$ 51,408	$ 261.28
$ 7,043	$ 7,043	$ 7,043	$ 3,682	$ 3,682	$ 9,413	$ 34,322	$ 72,228	$ 261.28
$ 150	$ 150	$ 150	$ 79	$ 79	$ 201	$ 732	$ 1,541	$ 261.28
$ 730	$ 730	$ 730	$ 422	$ 422	$ 1,079	$ 6,270	$ 10,382	$ 210.47
$ 4,466	$ 4,466	$ 4,466	$ 2,214	$ 2,214	$ 5,660	$ 37,986	$ 61,471	$ 206.49
$ 308	$ 308	$ 308	$ 178	$ 178	$ 456	$ 2,648	$ 4,385	$ 210.47
$ 5,090	$ 5,090	$ 5,090	$ 6,186	$ 6,186	$ 15,812	$ 8,527	$ 51,980	$ 586.62
$ 5,390	$ 5,390	$ 5,390	$ 1,603	$ 1,603	$ 4,099	$ 14,741	$ 38,217	$ 318.09
$ 6,077	$ 6,077	$ 6,077	$ 1,808	$ 1,808	$ 4,621	$ 16,620	$ 43,087	$ 318.09
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ 95,412	$ 95,412	$ 95,412	$ 64,885	$ 64,885	$ 165,850	$ 487,429	$ 1,069,285	

PC 6

PacifiCorp
Oregon Circuit Model Study
Commitment Calculations

Line		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
		Poles								
		1	2	3	4	5	6	7	Total	
1	% customer	13.04%	13.04%	13.04%			60.89%		100.00%	
2	Branch 6 Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ Per
3	% customer	0.42%	0.42%	0.42%	1.97%	1.97%	1.97%	92.83%	100.00%	Customer
4	Branch 7 Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
5	Branch Commitment Cost	$ 158,300	$ 158,300	$ 158,300	$ 158,300	$ 158,300	$ 158,300	$ 158,300		Average
6	Total	$ 158,300	$ 158,300	$ 158,300	$ 158,300	$ 158,300	$ 158,300	$ 158,300	$ 1,108,097	$ 922.10
7										
8									Total	
9									Demand	$ Per
10	Class Cost per Branch	1	2	3	4	5	6	7	Cost	Customer
11	Res - Schedule 4 (sec)	$ 115,850	$ 115,850	$ 115,850	$ 121,921	$ 121,921	$ 121,921	$ 133,375	$ 846,687	$ 841.90
12	GS - Schedule 23 - 0-15 kW (sec)	$ 29,122	$ 29,122	$ 29,122	$ 23,121	$ 23,121	$ 23,121	$ 17,171	$ 173,902	$ 1,296.15
13	GS - Schedule 23 - 15+ kW (sec)	$ 6,205	$ 6,205	$ 6,205	$ 4,927	$ 4,927	$ 4,927	$ 3,659	$ 37,055	$ 1,296.15
14	GS - Schedule 23 - Primary (pri)	$ 21	$ 21	$ 21	$ 16	$ 16	$ 16	$ 12	$ 123	$ 1,296.15
15	GS - Schedule 28 - 0-50 kW (sec)	$ 1,287	$ 1,287	$ 1,287	$ 872	$ 872	$ 872	$ 1,143	$ 7,621	$ 889.19
16	GS - Schedule 28 - 51-100 kW (sec)	$ 1,024	$ 1,024	$ 1,024	$ 694	$ 694	$ 694	$ 909	$ 6,063	$ 889.19
17	GS - Schedule 28 - 100 + kW (sec)	$ 636	$ 636	$ 636	$ 431	$ 431	$ 431	$ 564	$ 3,763	$ 889.19
18	GS - Schedule 28 - Primary (pri)	$ 17	$ 17	$ 17	$ 11	$ 11	$ 11	$ 15	$ 98	$ 889.19
19	GS - Schedule 30 - 0-300 kW (sec)	$ 33	$ 33	$ 33	$ 24	$ 24	$ 24	$ 51	$ 222	$ 594.22
20	GS - Schedule 30 - 300+ kW (sec)	$ 100	$ 100	$ 100	$ 64	$ 64	$ 64	$ 155	$ 649	$ 572.81
21	GS - Schedule 30 - Primary (pri)	$ 7	$ 7	$ 7	$ 5	$ 5	$ 5	$ 10	$ 45	$ 594.22
22	Irrigation - Sch 41	$ 3,929	$ 3,929	$ 3,929	$ 6,187	$ 6,187	$ 6,187	$ 1,199	$ 31,546	$ 2,718.91
23	LPS - Schedule 48 - 1 - 4 MW (sec)	$ 40	$ 40	$ 40	$ 15	$ 15	$ 15	$ 20	$ 187	$ 1,231.08
24	LPS - Schedule 48 - 1 - 4 MW (pri)	$ 29	$ 29	$ 29	$ 11	$ 11	$ 11	$ 14	$ 135	$ 1,231.08
25	LPS - Schedule 48 - > 4 MW (sec)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	LPS - Schedule 48 - > 4 MW (pri)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Check Total	$ 158,300	$ 158,300	$ 158,300	$ 158,300	$ 158,300	$ 158,300	$ 158,300	$ 1,108,097	

PacifiCorp
Oregon Circuit Model Study
Commitment Calculations

(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
Conductors								
1	2	3	4	5	6	7	Total	
13.04%	13.04%	13.04%	0.00%	0.00%	60.89%	0.00%	100.00%	
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ Per
0.42%	0.42%	0.42%	1.97%	1.97%	1.97%	92.83%	100.00%	Customer
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
$68,801	$68,801	$68,801	$68,801	$68,801	$68,801	$68,801		Average
$68,801	$68,801	$68,801	$68,801	$68,801	$68,801	$68,801	$481,605	$ 400.76
1	2	3	4	5	6	7	Total Demand Cost	$ Per Customer
$50,351	$50,351	$50,351	$52,990	$52,990	$52,990	$57,968	$367,990	$ 365.91
$12,657	$12,657	$12,657	$10,049	$10,049	$10,049	$ 7,463	$ 75,582	$ 563.34
$ 2,697	$ 2,697	$ 2,697	$ 2,141	$ 2,141	$ 2,141	$ 1,590	$ 16,105	$ 563.34
$ 9	$ 9	$ 9	$ 7	$ 7	$ 7	$ 5	$ 53	$ 563.34
$ 559	$ 559	$ 559	$ 379	$ 379	$ 379	$ 497	$ 3,312	$ 386.46
$ 445	$ 445	$ 445	$ 302	$ 302	$ 302	$ 395	$ 2,635	$ 386.46
$ 276	$ 276	$ 276	$ 187	$ 187	$ 187	$ 245	$ 1,635	$ 386.46
$ 7	$ 7	$ 7	$ 5	$ 5	$ 5	$ 6	$ 43	$ 386.46
$ 14	$ 14	$ 14	$ 11	$ 11	$ 11	$ 22	$ 97	$ 258.26
$ 44	$ 44	$ 44	$ 28	$ 28	$ 28	$ 67	$ 282	$ 248.96
$ 3	$ 3	$ 3	$ 2	$ 2	$ 2	$ 5	$ 20	$ 258.26
$ 1,708	$ 1,708	$ 1,708	$ 2,689	$ 2,689	$ 2,689	$ 521	$ 13,711	$1,181.70
$ 17	$ 17	$ 17	$ 7	$ 7	$ 7	$ 9	$ 81	$ 535.06
$ 13	$ 13	$ 13	$ 5	$ 5	$ 5	$ 6	$ 59	$ 535.06
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$68,801	$68,801	$68,801	$68,801	$68,801	$68,801	$68,801	$481,605	

PC 7

PacifiCorp
Oregon Circuit Model Study
Dedicated Circuit Trunk Costs
For Large Customers

		Voltage Delivery	
		Large GS + 4 MW	
		Poles	Conductor
1	Construction Cost Per Mile	$64,984	$110,173
2	Average Trunk Length	0.67	miles
3	Total Construction Cost	$43,539	$73,816
5	Customer Peak Demand (Sec)	3,591	kW
4	Customer Peak Demand (Pri)	8,630	kW
7	Demand Cost $/kW (Sec)	$12.13	$20.56
6	Demand Cost $/kW (Pri)	$5.04	$8.55

Construction Costs for Distribution Line type - 3 Phase -795 AAC & 477 AAC.

Line 1 - 'System-wide Pole and Conductor Costs' (PC 4)
Line 2 - Distribution Engineering Studies
Line 3 - Line 1 multiplied by Line 2
Line 4 - 'Circuit Distribution Model Inputs & Calculations' (PC 2)
Line 5 - Line 3 divided by Line 4

PC 8

PacifiCorp
Oregon Circuit Model Study
Trunk All Demand Costs
Outer Branches Commitment & Demand
Three Phase As Needed

		(A)	(B)	(C)	(D)	(E)	(F)	(G) =(C)*(F)	(H) =(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)	$ 841.90	$ 365.91	$ 191.87	$ 254.38	1,005.7	2,288.76	$ 439,152	$ 582,222
2	GS - Schedule 23 - 0-15 kW (sec)	$ 1,296.15	$ 563.34	$ 286.09	$ 332.38	134.2	170.48	$ 48,771	$ 56,664
3	GS - Schedule 23 - 15+ kW (sec)	$ 1,296.15	$ 563.34	$ 286.09	$ 332.38	28.6	184.21	$ 52,700	$ 61,228
4	GS - Schedule 23 - Primary (pri)	$ 1,296.15	$ 563.34	$ 286.09	$ 332.38	0.1	0.56	$ 159	$ 185
5	GS - Schedule 28 - 0-50 kW (sec)	$ 889.19	$ 386.46	$ 202.58	$ 261.28	8.6	131.23	$ 26,584	$ 34,287
6	GS - Schedule 28 - 51-100 kW (sec)	$ 889.19	$ 386.46	$ 202.58	$ 261.28	6.8	196.76	$ 39,859	$ 51,408
7	GS - Schedule 28 - 100 + kW (sec)	$ 889.19	$ 386.46	$ 202.58	$ 261.28	4.2	276.44	$ 56,002	$ 72,228
8	GS - Schedule 28 - Primary (pri)	$ 889.19	$ 386.46	$ 202.58	$ 261.28	0.1	5.90	$ 1,195	$ 1,541
9	GS - Schedule 30 - 0-300 kW (sec)	$ 594.22	$ 258.26	$ 141.52	$ 210.47	0.4	49.33	$ 6,981	$ 10,382
10	GS - Schedule 30 - 300+ kW (sec)	$ 572.81	$ 248.96	$ 137.30	$ 206.49	1.1	297.70	$ 40,874	$ 61,471
11	GS - Schedule 30 - Primary (pri)	$ 594.22	$ 258.26	$ 141.52	$ 210.47	0.1	20.84	$ 2,949	$ 4,385
12	Irrigation - Sch 41	$ 2,718.91	$ 1,181.70	$ 573.90	$ 586.62	11.6	88.61	$ 50,853	$ 51,980
13	LPS - Schedule 48 - 1 - 4 MW (sec)	$ 1,231.08	$ 535.06	$ 274.88	$ 318.09	0.2	120.14	$ 33,025	$ 38,217
14	LPS - Schedule 48 - 1 - 4 MW (pri)	$ 1,231.08	$ 535.06	$ 274.88	$ 318.09	0.1	135.45	$ 37,233	$ 43,087
15	Total -	$ 922.10	$ 400.76	$ 210.86	$ 269.59	1,201.7	3,966.39	$ 836,335	$ 1,069,285
16									
17	Large GS + 4 MW (sec)	$ -	$ -	$ 12.13	$ 20.56	-	3,590.54	$ 43,539	$ 73,816
18	Large GS + 4 MW (pri)	$ -	$ -	$ 5.04	$ 8.55	-	8,630.13	$ 43,539	$ 73,816
								$ 923,413	$ 1,216,917

	Commitment	Demand	Total
Poles	$ 1,108,097	$ 923,413	$ 2,031,511
Conductor	$ 481,605	$ 1,216,917	$ 1,698,522
Total	$ 1,589,702	$ 2,140,330	$ 3,730,033

Source : Column (A) - Pole Commitment Calculations' (PC 6)
Column (B) - Conductor Commitment Calculations' (PC 6)
Column (C) - Pole Demand Calculations' (PC 5)
Column (D) - Conductor Demand Calculations' (PC 5)
Column (E) - Average Customers by Hypothetical Circuit Branch' (PC 3)
Column (F) - Circuit kW Load by Branch' (PC 3)

XFMR 1

PacifiCorp
Oregon Marginal Cost Study
Transformer Demand and 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 $	(H) Weighted $ / kW	(I) Transformer Peak kW	(J) Tot. Trans. Demand $
				(A) x (B)		(C) / (D)		(E) x (F)			(H) x (I)
1	Res - Schedule 4	100.00%	350.24	350.24	4.12	85.07	513,581	43,690,336	1.62	3,378,644	5,477,821
2											
3	GS - Schedule 23										
4	1 Phase	80.77%	350.24	282.87	2.41	117.14					
5	3 Phase	19.23%	956.84	184.04	3.00	61.28					
6	0-15 kW					178.42	70,880	12,646,410	1.62	729,955	1,183,482
7											
8	1 Phase	54.22%	350.24	189.89	2.41	78.64					
9	3 Phase	45.78%	956.84	438.07	3.00	145.87					
10	15+ kW					224.51	15,103	3,390,774	1.62	412,650	669,032
11											
12	GS - Schedule 28										
13	1 Phase	29.27%	350.24	102.51	1.37	74.93					
14	3 Phase	70.73%	956.84	676.77	1.25	541.15					
15	0-50 kW					616.08	4,630	2,852,426	1.62	191,574	310,601
16											
17	1 Phase	14.60%	350.24	51.15	1.37	37.39					
18	3 Phase	85.40%	956.84	817.10	1.25	653.36					
19	51-100 kW					690.75	3,683	2,544,217	1.62	390,191	632,620
20											
21	1 Phase	2.48%	350.24	8.69	1.37	6.35					
22	3 Phase	97.52%	956.84	933.10	1.25	746.11					
23	100 + kW					752.46	2,286	1,719,951	1.62	486,664	789,031
24											
25	GS - Schedule 30										
26	1 Phase	0.42%	350.24	1.48	1.52	0.97					
27	3 Phase	99.58%	956.84	952.80	1.07	892.36					
28	0-300 kW					893.33	200	178,873	1.62	42,766	69,337
29											
30	1 Phase	0.06%	350.24	0.20	1.52	0.13					
31	3 Phase	99.94%	956.84	956.30	1.07	895.63					
32	300+ kW					895.76	606	542,623	1.62	247,527	401,317
33											
34	LPS - Schedule 48										
35	1 - 4 MW (sec)	100.00%	956.84	956.84	1.11	863.80	82	70,757	1.62	105,438	170,948
36	> 4 MW (sec)	100.00%	956.84	956.84	1.11	863.80	4	3,530	1.62	26,117	42,343
37											
38	Schedule 41- Irrigation										
39	1 Phase	15.70%	350.24	54.98	1.23	44.63					
40	3 Phase	84.30%	956.84	806.63	1.18	685.23					
41	Total					729.86	7,887	5,756,517	1.62	186,770	302,811
42											
43	Lighting	100.00%	350.24	350.24	3.01	116.26	7,437	864,633	1.62	11	18

XFMR2

PacifiCorp
Oregon Marginal Cost Study
Calculation of Escalation Factors for Transformers
(Regression weighted by number of transformer banks)

Line	Description	(A) Demand Related	(B) Adjusted for System Power Factor of 0.95	(C) Commitment Related	(D) Indexed to 2023	(E) Annualized $ @ 7.43%
			(A) / 0.95		(B) or (C) x 1.0459	(D) x 7.43%
1	1 Phase $/kW	$19.82	$20.86		$21.82	$1.62
2						
3	3 Phase $/kW	$19.82	$20.86		$21.82	$1.62
4						
5	1 Phase			$4,506.90	$4,713.84	$350.24
6	$/Transformer					
7						
8	3 Phase			$7,805.77		
9	Dummy Variable					
10						
11	3 Phase			$12,312.67	$12,878.01	$956.84
12	$/Transformer					

Escalation Factor 2023-2025
1.046

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	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
	Distribution O & M Expenses										
1	Total Distribution O & M Expense	68,689,786	70,580,614	69,136,197	61,535,374	61,513,756	61,139,370	68,212,991	83,124,296	90,983,613	114,178,049
2	Less:										
3	586 Meter Expense	2,991,325	3,120,160	2,616,262	1,645,292	1,079,103	883,546	655,758	1,279,281	1,305,324	1,394,304
4	587 Customer Installation Expense	4,352,166	4,244,231	4,157,616	5,227,622	5,089,251	5,107,333	5,763,027	6,702,788	6,553,641	6,997,994
5	597 Main. of Meters	1,628,742	1,653,908	1,198,881	10,098	59,787	85,408	231,001	235,870	158,233	185,682
6											
7	Total Adjusted Distribution O & M Expense										
8	Line 1 - (Lines 3 through 5)	59,717,552	61,562,315	61,163,438	54,652,362	55,285,614	55,063,083	61,563,205	74,906,357	82,966,414	105,600,068
9											
10											
11	Distribution Plant										
12	Total Distribution Plant	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	2,411,640,782	2,512,503,433
13	Less:										
14	370 Meters	59,706,364	60,110,283	60,993,623	62,541,755	65,791,804	76,927,946	90,849,203	96,302,523	97,893,679	101,011,391
15											
16	Adjusted Distribution Plant										
17	Line 12 - Line 14	1,763,300,899	1,806,531,062	1,855,628,755	1,907,760,892	1,974,512,380	2,051,964,719	2,088,697,950	2,214,927,014	2,313,747,103	2,411,492,042
18											
19											
20	O & M Expense Loading Factor										
21	Distribution O & M Loading	3.39%	3.41%	3.30%	2.86%	2.80%	2.68%	2.95%	3.38%	3.59%	4.38%
22	Line 8 / Line 17										
23											
24	Average Distribution O & M Loading										
25	Average of Line 22	3.27%									
26											
27	Distribution Annual Charge	7.43%									
28											
29	Annualized Distribution O & M Loading Factor										
30	Line 24 / Line 27	44.01%									

Footnotes:
Source: FERC Form 1 (State of Oregon) & Results of Operations

Services

PacifiCorp
Oregon Marginal Cost Study
Weighted Average Installed Service Drop Costs

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
1	Res - Schedule 4	533,013	100.00%					786	786	786	
2	Annualized - Line 1 x 7.43%								58	58	
3											
4	GS - Schedule 23										
5	0-15 kW										
6	kW = 0, 1 Phase	3,724	5.24%	976	826	60.7%	39.3%	917	48	59	
7	kW = 0, 3 Phase	4	0.01%	1,187	1,123	60.7%	39.3%	1,162	0		0
8	kW > 1, 1 Phase	53,708	75.53%	1,111	918	60.7%	39.3%	1,035	782	968	
9	kW > 1, 3 Phase	13,673	19.23%	1,309	1,203	60.7%	39.3%	1,268	244		1,267
10	Total 0-15 kW	71,109	100.00%						1,074	1,028	1,268
11	Annualized - Line 10 x 7.43%								80	76	94
12											
13	15+ kW										
14	1 Phase	8,215	54.22%	2,025	1,628	60.7%	39.3%	1,869	1,013	1,869	
15	3 Phase	6,937	45.78%	2,321	1,933	60.7%	39.3%	2,168	993		2,168
16	Total 15+ kW	15,152	100.00%						2,006	1,869	2,168
17	Annualized - Line 16 x 7.43%								149	139	161
18											
19	GS - Schedule 28										
20	0-50 kW										
21	1 Phase	1,328	29.24%	2,025	1,628	39.4%	60.6%	1,785	522	1,785	
22	3 Phase	3,213	70.76%	2,321	1,933	39.4%	60.6%	2,086	1,476		2,086
23	Total 0-50 kW	4,541	100.00%						1,998	1,785	2,086
24	Annualized - Line 23 x 7.43%								148	133	155
25											
26	51-100 kW										
27	1 Phase	527	14.59%	2,025	1,628	39.4%	60.6%	1,785	260	1,785	
28	3 Phase	3,086	85.41%	2,321	1,933	39.4%	60.6%	2,086	1,782		2,086
29	Total 51-100 kW	3,613	100.00%						2,042	1,785	2,086
30	Annualized - Line 29 x 7.43%								152	133	155
31											
32	100 + kW										
33	1 Phase	56	2.50%	3,745	4,150	39.4%	60.6%	3,991	100	3,991	
34	3 Phase	2,187	97.50%	4,106	5,035	39.4%	60.6%	4,669	4,552		4,669
35	Total 100 + kW	2,243	100.00%						4,652	3,991	4,669
36	Annualized - Line 35 x 7.43%								346	297	347
37											
38	GS - Schedule 30										
39											
40	0-300 kW										
41	1 Phase	1	0.50%	3,745	4,150	17.0%	83.0%	4,081	21		
42	3 Phase	198	99.50%	4,106	5,035	17.0%	83.0%	4,877	4,853		
43	Total 0-300 kW	199	100.00%						4,873		
44	Annualized - Line 43 x 7.43%								362		
45											
46	300+ kW										
47	1 Phase	-	0.00%	9,834	8,163	17.0%	83.0%	8,447	-		
48	3 Phase	600	100.00%	9,834	8,163	17.0%	83.0%	8,447	8,447		
49	Total 300+ kW	600	100.00%						8,447		
50	Annualized - Line 49 x 7.43%								628		
51											
52	LPS - Schedule 48										
53	1 - 4 MW (sec)	81	100.00%		30,522	0.0%	100.0%	30,522	30,522		
54	Annualized - Line 53 x 7.43%								2,268		
55											
56	> 4 MW (sec)	4	100.00%		30,522	0.0%	100.0%	30,522	30,522		
57	Annualized - Line 56 x 7.43%								2,268		

Meters

PacifiCorp
Oregon Marginal Cost Study
Weighted Average Installed Meter Costs

		(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	533,013	100.00%	100.00%		231.80	231.80	231.80	
3	Annualized - (Line 1) x 7.43%						17.22	17.22	
4									
5	GS - Schedule 23								
6	0-15 kW								
7	kW = 0, 1 Phase	3,724	5.24%	6.48%		221.73	11.61	14.38	
8	kW = 0, 3 Phase	4	0.01%		0.03%	347.24	0.02		0.10
9	kW > 1, 1 Phase	53,708	75.53%	93.52%		221.73	167.47	207.36	
10	kW > 1, 3 Phase	13,673	19.23%		99.97%	347.24	66.77		347.14
11	Total 0-15 kW	71,109	100.00%	100.00%	100.00%		245.87	221.74	347.24
12	Annualized - (Line 11) x 7.43%						18.27	16.48	25.80
13									
14	15+ kW								
15	1 Phase	8,215	54.22%	100.00%		221.73	120.22	221.73	
16	3 Phase W/O KVAR	3,591	23.70%		51.77%	347.24	82.30		179.75
17	3 Phase With KVAR	3,346	22.08%		48.23%	347.24	76.68		167.49
18	Total 15+ kW	15,152	100.00%	100.00%	100.00%		279.20	221.73	347.24
19	Annualized - (Line 18) x 7.43%						20.74	16.47	25.80
20									
21	Primary								
22	12.47 KV 4-wire Wye	50	100.00%		100.00%	16,090.36	16,090.36		16,090.36
23	Annualized - (Line 22) x 7.43%						1,195.51		1,195.51
24									

Line	Load Class	Customers	1 & 3 Phase	1 Phase	3 Phase	Metering Cost	1 & 3 Phase	1 Phase	3 Phase
25	GS - Schedule 28								
26	0-50 kW								
27	kW = 0, 1 Phase	7	0.15%	0.53%		221.73	0.34	1.17	
28	kW = 0, 3 Phase	10	0.22%		0.31%	347.24	0.76		1.08
29	kW > 1, 1 Phase	1,321	29.09%	99.47%		221.73	64.50	220.57	
30	kW > 1, 3 Phase	3,203	70.54%		99.69%	347.24	244.93		346.16
31	Total 0-50 kW	4,541	100.00%	100.00%	100.00%		310.53	221.74	347.24
32	Annualized - (Line 31) x 7.43%						23.07	16.48	25.80
33									
34	51-100 kW								
35	1 Phase	527	14.59%	100.00%		221.73	32.34	221.73	
36	3 Phase W/O KVAR	1,431	39.61%		46.37%	347.24	137.53		161.02
37	3 Phase With KVAR	1,655	45.81%		53.63%	347.24	159.06		186.22
38	Total 51-100 kW	3,613	100.00%	100.00%	100.00%		328.93	221.73	347.24
39	Annualized - (Line 38) x 7.43%						24.44	16.47	25.80
40									
41	100 + kW								
42	1 Phase	56	2.50%	100.00%		1,767.60	44.13	1,767.60	
43	3 Phase W/O KVAR	936	41.73%		42.80%	1,928.67	804.83		825.44
44	3 Phase With KVAR	1,251	55.77%		57.20%	1,928.67	1,075.69		1,103.23
45	Total 100 + kW	2,243	100.00%	100.00%	100.00%		1,924.65	1,767.60	1,928.67
46	Annualized - (Line 45) x 7.43%						143.00	131.33	143.30
47									
48	Primary								
49	12.47 KV 4-wire Wye	59	100.00%		100.00%	16,090.36	16,090.36		16,090.36
50	Annualized - (Line 49) x 7.43%						1,195.51		1,195.51
51									

Line	Load Class	Customers	1 & 3 Phase	1 Phase	3 Phase	Metering Cost	1 & 3 Phase	1 Phase	3 Phase
52	GS - Schedule 30								
53	0-300 kW								
54	1 Phase	1	0.50%	100.00%		1,767.60	8.90	1,767.60	
55	3 Phase W/O KVAR	43	21.50%		21.61%	1,928.67	414.59		416.69
56	3 Phase With KVAR	155	78.00%		78.39%	1,928.67	1,504.36		1,511.98
57	Total 0-300 kW	199	100.00%	100.00%	100.00%		1,927.85	1,767.60	1,928.67
58	Annualized - (Line 57) x 7.43%						143.24	131.33	143.30
59									
60	300+ kW								
61	1 Phase	-	0.00%	100.00%		2,325.07	-	2,325.07	
62	3 Phase W/O KVAR	155	25.83%		25.83%	1,928.67	498.24		498.24
63	3 Phase With KVAR	445	74.17%		74.17%	1,928.67	1,430.43		1,430.43
64	Total 300+ kW	600	100.00%	100.00%	100.00%		1,928.67	2,325.07	1,928.67
65	Annualized - (Line 64) x 7.43%						143.30	172.75	143.30
66									
67	Primary								
68	12.47 KV 4-wire Wye	40	100.00%		100.00%	16,090.36	16,090.36		16,090.36
69	Annualized - (Line 68) x 7.43%						1,195.51		1,195.51
70									
71	LPS - Schedule 48								
72	1 - 4 MW (sec)	81	100.00%		100.00%	2,445.35	2,445.35		2,445.35
73	Annualized - (Line 72) x 7.43%						181.69		181.69
74									
75	1 - 4 MW (pri)	58	100.00%		100.00%	16,090.36	16,090.36		16,090.36
76	Annualized - (Line 75) x 7.43%						1,195.51		1,195.51
77									
78	> 4 MW (sec)	4	100.00%		100.00%	2,445.35	2,445.35		2,445.35
79	Annualized - (Line 78) x 7.43%						181.69		181.69
80									
81	> 4 MW (pri)	24	100.00%		100.00%	16,090.36	16,090.36		16,090.36
82	Annualized - (Line 81) x 7.43%						1,195.51		1,195.51
83									
84	Trans (trn)	7	100.00%		100.00%	247,538.33	247,538.33		247,538.33
85	Annualized - (Line 84) x 7.43%						18,392.10		18,392.10
86									

Line	Load Class	Customers	1 & 3 Phase	1 Phase	3 Phase	Metering Cost	1 & 3 Phase	1 Phase	3 Phase
87									
88	Irrigation - Schedule 41 (Annual)								
89	0 - 50 kW								
90	kW = 0, 1 Phase	-	0.00%	0.00%		221.73	-	-	
91	kW = 0, 3 Phase	-	0.00%		0.00%	347.24	-		-
92	kW > 1, 1 Phase	965	14.69%	100.00%		221.73	32.57	221.73	
93	kW > 1, 3 Phase	4,255	64.78%		82.08%	347.24	224.93		285.02
94									
95	51 - 300 kW								
96	1 Phase	-	0.00%	0.00%		221.73	-	-	
97	3 Phase W/O KVAR	147	2.24%		2.84%	347.24	7.77		9.85
98	3 Phase With KVAR	763	11.62%		14.72%	347.24	40.33		51.11
99									
100	> 300 kW								
101	1 Phase	-	0.00%	0.00%		2,325.07	-	-	
102	3 Phase W/O KVAR	4	0.06%		0.08%	1,928.67	1.17		1.49
103	3 Phase With KVAR	15	0.23%		0.29%	1,928.67	4.40		5.58
104	Total Irrigation	6,569	100.00%	100.00%	100.00%	1,928.67	311.17	221.73	353.05
105							23.12	16.47	26.23
106									
107	Primary	-	100.00%		100.00%	-	-		-
108							-		-
109									
110	Lighting - Schedule 54	98	100.00%		100.00%		18.27		
111									

Footnote:
Column A - Customer inputs from Pricing Dept - data based on 12 months ended June 2023.

Meter&ServiceCost

PacifiCorp
Oregon Marginal Cost Study
Summary of Average Installed Costs
Meters

Line	Load Class	(A) Metering Standard	(B) Meter Cost in 2023 Dollars	(C) Indexed to 2025 Dollars	(D) Percent Use	(E) Total Installed Cost per Meter
	Residential					
1	Small Load	DM221J	$212	221.73	49.36%	109.45
2	All Electric	DM221K	$231	241.61	50.64%	122.35
3					100.00%	231.80
4						
5	0 - 15 kW					
6	kW = 0, 1 Phase	DM221J	$212	221.73	100.00%	221.73
7						
8	kW = 0, 3 Phase	DM241D	$332	347.24	100.00%	347.24
9						
10	kW > 1, 1 Phase	DM221J	$212	221.73	100.00%	221.73
11						
12	kW > 1, 3 Phase	DM241D	$332	347.24	100.00%	347.24
13						
14						
15	15 - 100 kW					
16	1 Phase	DM221J	$212	221.73	100.00%	221.73
17						
18	3 Phase wo / KVAR	DM241D	$332	347.24	100.00%	347.24
19						
20	3 Phase with KVAR	DM241D	$332	347.24	100.00%	347.24
21						

23	100 - 300 kW					
24	1 Phase	DM231FBB	$1,690	1,767.60	100.00%	1,767.60
26	3 Phase wo / KVAR	DM271DEC	$1,844	1,928.67	100.00%	1,928.67
28	3 Phase with KVAR	DM271DEC	$1,844	1,928.67	100.00%	1,928.67
31	300-1000 kW					
32	W/O KVAR, 1 Phase	DM231FFE	$2,223	2,325.07	100.00%	2,325.07
34	W/O KVAR, 3 Phase	DM271DEC	$1,844	1,928.67	100.00%	1,928.67
36	W/KVAR, 3 Phase	DM271DEC	$1,844	1,928.67	100.00%	1,928.67
39	1000 kW and over					
40	Secondary Volt	DM271DEG	$2,338	2,445.35	100.00%	2,445.35
42	Primary Metering					
43	'13.8 KV 3-wire	DM101ACBA	$11,109	11,619.07		11,619.07
44	'12.47 KV 4-wire Wye	DM121ACJAD	$15,384	16,090.36		16,090.36
45	24.9 KV 4-wire Wye	DM121BFIAD	$15,060	15,751.48		15,751.48
46	35 KV 4-wire Wye	DM131BBAH	$21,819	22,820.83		22,820.83
48	Transmission		247,538			

Escalation Factor
2023 - 2025
1.0459

PacifiCorp
Oregon Marginal Cost Study
Summary of Average Installed Costs
Service Drops

Line	Load Class	(A) Service Conductor	(B) Cost in 2023 Dollars	(C) Indexed to 2025 Dollars	(D) Percent Use	(E) Total Cost per Service
				(B) x 1.0459		
	Residential					
1	OH - small load	#2 Triplex*	642	671.48	29.9%	200.59
2	OH - all electric	1/0 Triplex	732	765.61	26.6%	203.45
3	UG - small load	1/0 Triplex	790	826.27	19.5%	161.03
4	UG - all electric	4/0 Triplex	878	918.31	24.1%	221.00
5						786.06
6	0 - 15 kW					
7	kW = 0, 1 Phase	OH - 1/0 Triplex	933	975.84		
8	kW = 0, 1 Phase	UG - 1/0 Triplex	790	826.27		
9	kW = 0, 3 Phase	OH - 1/0 Quadruplex	1,135	1,187.11		
10	kW = 0, 3 Phase	UG - 1/0 Quadruplex	1,074	1,123.31		
11	kW > 1, 1 Phase	OH - 4/0 Triplex	1,062	1,110.76		
12	kW > 1, 1 Phase	UG - 4/0 Triplex	878	918.31		
13	kW > 1, 3 Phase	OH - 4/0 Quadruplex	1,252	1,309.49		
14	kW > 1, 3 Phase	UG - 4/0 Quadruplex	1,150	1,202.80		
15						
16	16 - 100 kW					
17	1 Phase	OH - 2-4/0 Triplex	1,936	2,024.89		
18	1 Phase	UG - 2-4/0 Triplex	1,557	1,628.49		
19	3 Phase	OH - 2-4/0 Quadruplex	2,219	2,320.89		
20	3 Phase	UG - 2-4/0 Quadruplex	1,848	1,932.85		
21						

101 - 300 kW			
1 Phase	3-500 & 350N	3,581	3,745.42
1 Phase	3- 750 & 500 N	3,968	4,150.19
3 Phase	OH - 3-4/0 Quadruplex	3,926	4,106.26
3 Phase	4-350 Quad	4,814	5,035.04
301 - 1000 kW			
3 Phase	3-750 kcmil Quad.	9,402	9,833.70
3 Phase	4-750 kcmil Quad.	7,805	8,163.37
1000 kW and Over			
Secondary Voltage	12-1000 kcmil Quad.	29,182	30,521.90
Primary Voltage	---	---	---
		Weighted %	
Residential Overhead % =	56.4%		
% of Overhead Which Are Small Load=	52.9%	29.9%	
% of Overhead Which Are All Electric=	47.1%	26.6%	
Residential Underground % =	43.6%		
% of Underground Which Are Small Load=	44.7%	19.5%	
% of Underground Which Are All Electric=	55.3%	24.1%	
Total OH & UG		100.0%	

DistMeters

PacifiCorp
Oregon Marginal Cost Study
Distribution Meters Expense
Loading Factor

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
Line	Description	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
	Distribution Meters Expenses										
1	586 Meter Expense	2,991,325	3,120,160	2,616,262	1,645,292	1,079,103	883,546	655,758	1,279,281	1,305,324	1,394,304
2	597 Main. of Meters	1,628,742	1,653,908	1,198,881	10,098	59,787	85,408	231,001	235,870	158,233	185,682
3											
4	Total Adjusted Distribution Meters Expense	4,620,067	4,774,068	3,815,143	1,655,390	1,138,890	968,955	886,759	1,515,150	1,463,558	1,579,986
5	Line 1 + Line 2										
6											
7											
8											
9	Distribution Meters										
10	370 Meters	59,706,364	60,110,283	60,993,623	62,541,755	65,791,804	76,927,946	90,849,203	96,302,523	97,893,679	101,011,391
11											
12											
13											
14	Meters Expense Loading Factor										
15	Meter O&M Loading	7.74%	7.94%	6.25%	2.65%	1.73%	1.26%	0.98%	1.57%	1.50%	1.56%
16	Line 4 / Line 10										
17											
18	Average Meter O&M Loading	3.32%									
19	Average of Line 15										
20											
21	Distribution Annual Charge	7.43%									
22											
23	Annualized Meter O&M Loading Factor	44.66%									
24	Line 18 / Line 21										

CustExpense

PacifiCorp
Oregon Marginal Cost Study
Summary of Customer Accounting Expense
By Schedule
December 2025 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	513,581	86,033	10,658	847	178	3,311	7,437	622,045
2			Write-offs By Schedule	3,547,018	81,618	105,993	54,523	144,768	41,210	-	3,975,129
3											
4											
5	901	Supervision	Account 902 + 903 + 904	18,345,139	2,646,042	538,628	120,240	292,903	165,711	191,305	22,299,968
6	901		% of Total 902 + 903 + 904	82.27%	11.87%	2.42%	0.54%	1.31%	0.74%	0.86%	100.00%
7	901		Total 901 $	695,382	100,300	20,417	4,558	11,103	6,281	7,252	845,292
8	901		$ Per Customer	1.35	1.17	1.92	5.38	62.37	1.90	0.98	1.36
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	-	-	-	-	-	-	-	-
12	902		% of Total $	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
13	902		Total 902 $	-	-	-	-	-	-	-	-
14	902		$ Per Customer	-	-	-	-	-	-	-	-
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	513,581	104,023	14,950	1,188	2,062	4,001	7,932	647,736
18	903		% of Total $	79.29%	16.06%	2.31%	0.18%	0.32%	0.62%	1.22%	100.00%
19	903		Total 903 $	12,387,179	2,508,948	360,591	28,656	49,735	96,490	191,305	15,622,905
20	903		$ Per Customer	25.10	29.16	33.83	33.83	279.41	29.14	25.72	25.12
21											
22	904	Uncollectibles	% of Write-offs	89.23%	2.05%	2.67%	1.37%	3.64%	1.04%	0.00%	100.00%
23	904		Total 904 $	5,957,960	137,094	178,037	91,583	243,168	69,221	-	6,677,063
24	904		$ Per Customer	11.60	1.59	16.70	108.13	1,366.11	20.91	-	10.73
25											
26	905	Misc Cust Acct Expense	Account 902 + 903 + 904	18,345,139	2,646,042	538,628	120,240	292,903	165,711	191,305	22,299,968
27	905		% of Total 902 + 903 + 904	82.27%	11.87%	2.42%	0.54%	1.31%	0.74%	0.86%	100.00%
28	905		Total 905 $	3,699	534	109	24	59	33	39	4,497
29	905		$ Per Customer	0.01	0.01	0.01	0.03	0.33	0.01	0.01	0.01
30											
31	907-910	Supervision, Cust. Assist.	Average Number of customers	513,581	86,033	10,658	847	178	3,311	7,437	622,045
32	907-910	Info & Instructional Exp.,	% of Total	82.56%	13.83%	1.71%	0.14%	0.03%	0.53%	1.20%	100.00%
33	907-910	Misc Cust Svc & Info Exp.	Total 907-910 $	4,792,775	802,866	99,461	7,904	1,661	30,896	69,403	5,804,967
34	907-910		$ Per Customer	9.33	9.33	9.33	9.33	9.33	9.33	9.33	9.33
35											
36											
37	901 - 910		Total 901 - 910 $	23,836,996	3,549,741	658,615	132,726	305,726	202,922	267,999	28,954,724
38											
39			$ Per Customer	47.40	41.26	61.80	156.70	1,717.56	61.29	36.04	46.55

	2018	2019	2020	2021	2022	Actual Year Adjusted 2025
Customer Accounting						
901 Supervision	776,328	712,826	706,833	699,844	884,456	845,292
902 Meter Reading Expense	9,772,620	4,869,243	2,245,673	2,432,215	2,193,524	4,905,160
903 Cust Records & Collection	15,706,759	15,074,984	13,295,839	12,573,679	12,954,582	15,622,905
904 Uncollectible Accounts	4,639,879	5,061,708	6,263,999	5,394,731	8,652,079	6,677,063
905 Misc Cust Acct Expense	4,809	5,606	8,479	830	47	4,497
Total	30,900,395	25,724,366	22,520,822	21,101,299	24,684,688	28,054,917
Customer Service & Info Expense						
907 Supervision	36,862	2,105	208	(166)	491	9,223
908 Cust Assistance Expense	2,730,139	3,325,682	3,466,926	3,935,825	3,415,781	3,767,567
909 Info & Instructional Expense	2,077,877	2,316,089	1,879,350	1,307,108	1,409,632	2,024,348
910 Misc Cust Svc & Info Expense	12,955	1,416	541	394	1,242	3,829
Total	4,857,833	5,645,291	5,347,026	5,243,161	4,827,146	5,804,967
Inflation Adjustment	1.1701	1.1442	1.1188	1.0939	1.0697	

Source:
Source: State of Oregon results of operations

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)
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%
2021	173,646	32,098,210	0.54%
2022	260,189	32,845,783	0.79%
10 Year Average A&G to EPIS Loading Factor			0.58%

Footnotes:
(A) FERC Form 1 Page 323, line 197
(B) FERC Form 1 Page 207, line 104

Charge

PacifiCorp
Oregon Marginal Cost Study
Calculation of Annual Charges

Line	Description	(A) System Transmission	(B) Distribution
1	Levelized Income Taxes	1.05%	0.96%
2	Levelized Property Tax	0.82%	0.75%
3	Total	1.87%	1.71%
4			
5	Levelized Income & Property Taxes	$18.70	$17.10
6	(per $1,000 of Investment)		
7			
8	Expected Life	65	54
9			
10	Nominal Interest Rate	7.74%	7.74%
11			
12	Present Value: Income **	$239.70	$216.98
13	Taxes & Property Taxes per	(PV of $18.70 per year	(PV of $17.10 per year
14	$1,000 of Investment		for 54 years at 7.74%)
15			
16	Removal Cost Per $1,000 Investment	$180.83	$452.69
17			
18	Present Value: Removal Cost	$1.42	$8.08
19	at End of Useful Life	(PV of $180.83 per year	(PV of $452.69 per year
20		65 years at 7.74%)	54 years at 7.74%)
21			
22	Investment and Taxes	$1,241.12	$1,225.06
23	w/o PVCD (Line 12 + Line 18 + $1000)		
24			
25	PVCD Factor	0.035332	0.035688
26			
27	PVCD $ (Line 22 x Line 25)	$43.85	$43.72
28			
29	Total (Line 22 + Line 27)	$1,284.97	$1,268.78
30			
31	EOY Annual Charge ***	$67.52	$68.53
32			
33	Annual Economic Carrying	6.75%	6.85%
34	Adm &Gen Expense Loading Factor	0.58%	0.58%
35			
36	Annual Econ Carrying + A&G Loading	7.33%	7.43%

Footnotes:

From Financial Analysis - 18.70*(1/0.0774-(1/0.0774)/(1+0.0774)^65)
** PV = Ln(5) x [1/r - (1/r)/(1+r)^a] 17.10*(1/0.0774-(1/0.0774)/(1+0.0774)^54)

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
a = expected investment life
r = nominal interest rate

Financial Inputs	
Weighted Cost of Capital	7.74%
Borrowing Rate	7.74%
Average Inflation	2.27%
Real Cost of Capital	
(1+0.0774)/(1+0.0227)-1 =	5.35%

Levelized	
Income Taxes	
Transmission	1.05%
Distribution	0.96%
Property Taxes	
Transmission	0.82%
Distribution	0.75%

Source:
Cost of Capital/Borrowing Rate: Revenue Requirement (OR Jurisdictional Allocation Model)
Income & Property Taxes: 2023 Use of Facilities Report
PacifiCorp's 2023 IRP

Iowa Curves

PacifiCorp
Oregon Marginal Cost Study
Present Value of Cost of Dispersion Factor

Iowa Curve R 2 & 65 Year Average Life

Real Cost of Capital = 5.35%

YEAR	(A) PVCD	(B) % RENEWED	(C) NUM1	(D) DEM1	(E) NUM1/DEM1	(F) NUM2	(G) DEM2	(H) NUM2/DEM2	(I) INSTANCE	(J) Iowa R 2.0
	((A) {yr-1} +(I)) / 100	((J,{yr-1})-(J)) * 100	(B)	1.0535 ^Year	(C) / (D)	(B)	1.0535 ^62	(F) / (G)	(E) - (H)	(Given)
										100.0000
1	0.00071	7.82%	0.0782	1.05349	0.07423	0.0782	25.29412	0.00309	0.07114	99.9218
2	0.00206	15.63%	0.1563	1.10984	0.14083	0.1563	25.29412	0.00618	0.13465	99.7655
3	0.00333	15.63%	0.1563	1.16920	0.13368	0.1563	25.29412	0.00618	0.12750	99.6092
4	0.00459	16.32%	0.1632	1.23174	0.13250	0.1632	25.29412	0.00645	0.12604	99.4460
5	0.00594	18.40%	0.1840	1.29762	0.14180	0.1840	25.29412	0.00727	0.13452	99.2620
6	0.00721	18.40%	0.1840	1.36702	0.13460	0.1840	25.29412	0.00727	0.12732	99.0780
7	0.00842	18.40%	0.1840	1.44014	0.12777	0.1840	25.29412	0.00727	0.12049	98.8940
8	0.00976	21.60%	0.2160	1.51717	0.14237	0.2160	25.29412	0.00854	0.13383	98.6780
9	0.01102	21.60%	0.2160	1.59832	0.13514	0.2160	25.29412	0.00854	0.12660	98.4620
10	0.01222	21.60%	0.2160	1.68381	0.12828	0.2160	25.29412	0.00854	0.11974	98.2460
11	0.01349	24.28%	0.2428	1.77387	0.13688	0.2428	25.29412	0.00960	0.12728	98.0032
12	0.01474	25.17%	0.2517	1.86875	0.13469	0.2517	25.29412	0.00995	0.12474	97.7515
13	0.01592	25.17%	0.2517	1.96871	0.12785	0.2517	25.29412	0.00995	0.11790	97.4998
14	0.01712	27.18%	0.2718	2.07401	0.13105	0.2718	25.29412	0.01075	0.12030	97.2280
15	0.01834	29.20%	0.2920	2.18494	0.13364	0.2920	25.29412	0.01154	0.12210	96.9360
16	0.01949	29.20%	0.2920	2.30181	0.12686	0.2920	25.29412	0.01154	0.11531	96.6440
17	0.02063	30.33%	0.3033	2.42493	0.12508	0.3033	25.29412	0.01199	0.11308	96.3407
18	0.02181	33.72%	0.3372	2.55463	0.13200	0.3372	25.29412	0.01333	0.11866	96.0035
19	0.02293	33.73%	0.3373	2.69127	0.12533	0.3373	25.29412	0.01334	0.11200	95.6662
20	0.02399	33.72%	0.3372	2.83522	0.11893	0.3372	25.29412	0.01333	0.10560	95.3290
21	0.02513	38.71%	0.3871	2.98687	0.12960	0.3871	25.29412	0.01530	0.11430	94.9419
22	0.02621	38.71%	0.3871	3.14663	0.12302	0.3871	25.29412	0.01530	0.10772	94.5548
23	0.02722	38.70%	0.3870	3.31493	0.11674	0.3870	25.29412	0.01530	0.10144	94.1678
24	0.02828	42.91%	0.4291	3.49224	0.12287	0.4291	25.29412	0.01696	0.10591	93.7387
25	0.02931	44.31%	0.4431	3.67903	0.12044	0.4431	25.29412	0.01752	0.10292	93.2956
26	0.03028	44.31%	0.4431	3.87582	0.11432	0.4431	25.29412	0.01752	0.09681	92.8525
27	0.03125	47.40%	0.4740	4.08312	0.11609	0.4740	25.29412	0.01874	0.09735	92.3785
28	0.03223	50.49%	0.5049	4.30152	0.11738	0.5049	25.29412	0.01996	0.09742	91.8736
29	0.03314	50.49%	0.5049	4.53160	0.11142	0.5049	25.29412	0.01996	0.09146	91.3687
30	0.03403	52.20%	0.5220	4.77398	0.10934	0.5220	25.29412	0.02064	0.08871	90.8467
31	0.03494	57.32%	0.5732	5.02933	0.11397	0.5732	25.29412	0.02266	0.09131	90.2735
32	0.03580	57.33%	0.5733	5.29833	0.10820	0.5733	25.29412	0.02267	0.08554	89.7002
33	0.03660	57.32%	0.5732	5.58173	0.10269	0.5732	25.29412	0.02266	0.08003	89.1270
34	0.03744	64.83%	0.6483	5.88028	0.11025	0.6483	25.29412	0.02563	0.08462	88.4787
35	0.03823	64.83%	0.6483	6.19480	0.10465	0.6483	25.29412	0.02563	0.07902	87.8304
36	0.03897	64.83%	0.6483	6.52614	0.09934	0.6483	25.29412	0.02563	0.07371	87.1821
37	0.03972	70.97%	0.7097	6.87521	0.10323	0.7097	25.29412	0.02806	0.07517	86.4724
38	0.04044	73.02%	0.7302	7.24295	0.10082	0.7302	25.29412	0.02887	0.07195	85.7422
39	0.04111	73.01%	0.7301	7.63035	0.09568	0.7301	25.29412	0.02886	0.06682	85.0121
40	0.04177	77.46%	0.7746	8.03848	0.09636	0.7746	25.29412	0.03062	0.06574	84.2375
41	0.04241	81.91%	0.8191	8.46844	0.09672	0.8191	25.29412	0.03238	0.06434	83.4184
42	0.04301	81.91%	0.8191	8.92139	0.09181	0.8191	25.29412	0.03238	0.05943	82.5993
43	0.04357	84.31%	0.8431	9.39857	0.08971	0.8431	25.29412	0.03333	0.05637	81.7562
44	0.04413	91.50%	0.9150	9.90128	0.09241	0.9150	25.29412	0.03617	0.05624	80.8412
45	0.04465	91.51%	0.9151	10.43087	0.08773	0.9151	25.29412	0.03618	0.05155	79.9261
46	0.04512	91.51%	0.9151	10.98879	0.08328	0.9151	25.29412	0.03618	0.04710	79.0110
47	0.04559	101.66%	1.0166	11.57656	0.08782	1.0166	25.29412	0.04019	0.04762	77.9944
48	0.04603	101.66%	1.0166	12.19576	0.08336	1.0166	25.29412	0.04019	0.04317	76.9778
49	0.04641	101.66%	1.0166	12.84807	0.07912	1.0166	25.29412	0.04019	0.03893	75.9612
50	0.04679	109.65%	1.0965	13.53529	0.08101	1.0965	25.29412	0.04335	0.03766	74.8647
51	0.04714	112.31%	1.1231	14.25925	0.07876	1.1231	25.29412	0.04440	0.03436	73.7416

52	0.04744	112.31%	1.1231	15.02194	0.07476	1.1231	25.29412	0.04440	0.03036	72.6185
53	0.04772	117.73%	1.1773	15.82543	0.07439	1.1773	25.29412	0.04654	0.02785	71.4412
54	0.04797	123.17%	1.2317	16.67189	0.07388	1.2317	25.29412	0.04870	0.02518	70.2095
55	0.04818	123.17%	1.2317	17.56362	0.07013	1.2317	25.29412	0.04870	0.02143	68.9778
56	0.04837	125.87%	1.2587	18.50306	0.06803	1.2587	25.29412	0.04976	0.01826	67.7191
57	0.04852	133.97%	1.3397	19.49274	0.06873	1.3397	25.29412	0.05296	0.01576	66.3794
58	0.04865	133.97%	1.3397	20.53535	0.06524	1.3397	25.29412	0.05296	0.01227	65.0397
59	0.04874	133.97%	1.3397	21.63374	0.06193	1.3397	25.29412	0.05296	0.00896	63.7000
60	0.04880	144.25%	1.4425	22.79087	0.06329	1.4425	25.29412	0.05703	0.00626	62.2575
61	0.04883	144.24%	1.4424	24.00989	0.06008	1.4424	25.29412	0.05703	0.00305	60.8151
62	0.04883	144.25%	1.4425	25.29412	0.05703	1.4425	25.29412	0.05703	-	59.3726
63	0.04880	151.14%	1.5114	26.64704	0.05672	1.5114	25.29412	0.05975	(0.00303)	57.8612
64	0.04874	153.45%	1.5345	28.07232	0.05466	1.5345	25.29412	0.06067	(0.00600)	56.3267
65	0.04865	153.45%	1.5345	29.57383	0.05189	1.5345	25.29412	0.06067	(0.00878)	54.7922
66	0.04853	157.20%	1.5720	31.15566	0.05046	1.5720	25.29412	0.06215	(0.01169)	53.2202
67	0.04839	160.95%	1.6095	32.82210	0.04904	1.6095	25.29412	0.06363	(0.01459)	51.6107
68	0.04822	160.95%	1.6095	34.57767	0.04655	1.6095	25.29412	0.06363	(0.01708)	50.0012
69	0.04802	162.24%	1.6224	36.42714	0.04454	1.6224	25.29412	0.06414	(0.01960)	48.3788
70	0.04780	166.10%	1.6610	38.37553	0.04328	1.6610	25.29412	0.06567	(0.02238)	46.7178
71	0.04755	166.09%	1.6609	40.42814	0.04108	1.6609	25.29412	0.06566	(0.02458)	45.0569
72	0.04729	166.09%	1.6609	42.59053	0.03900	1.6609	25.29412	0.06566	(0.02667)	43.3960
73	0.04699	168.18%	1.6818	44.86859	0.03748	1.6818	25.29412	0.06649	(0.02901)	41.7142
74	0.04669	168.19%	1.6819	47.26849	0.03558	1.6819	25.29412	0.06649	(0.03091)	40.0323
75	0.04636	168.18%	1.6818	49.79676	0.03377	1.6818	25.29412	0.06649	(0.03272)	38.3505
76	0.04602	167.10%	1.6710	52.46026	0.03185	1.6710	25.29412	0.06606	(0.03421)	36.6795
77	0.04566	166.74%	1.6674	55.26623	0.03017	1.6674	25.29412	0.06592	(0.03575)	35.0121
78	0.04529	166.74%	1.6674	58.22227	0.02864	1.6674	25.29412	0.06592	(0.03728)	33.3447
79	0.04491	164.06%	1.6406	61.33643	0.02675	1.6406	25.29412	0.06486	(0.03811)	31.7041
80	0.04452	161.39%	1.6139	64.61716	0.02498	1.6139	25.29412	0.06381	(0.03883)	30.0902
81	0.04412	161.38%	1.6138	68.07336	0.02371	1.6138	25.29412	0.06380	(0.04009)	28.4764
82	0.04371	159.09%	1.5909	71.71443	0.02218	1.5909	25.29412	0.06290	(0.04071)	26.8855
83	0.04331	152.22%	1.5222	75.55025	0.02015	1.5222	25.29412	0.06018	(0.04003)	25.3633
84	0.04290	152.21%	1.5221	79.59123	0.01912	1.5221	25.29412	0.06018	(0.04105)	23.8412
85	0.04248	152.22%	1.5222	83.84836	0.01815	1.5222	25.29412	0.06018	(0.04203)	22.3190
86	0.04208	139.60%	1.3960	88.33319	0.01580	1.3960	25.29412	0.05519	(0.03939)	20.9230
87	0.04168	139.60%	1.3960	93.05791	0.01500	1.3960	25.29412	0.05519	(0.04019)	19.5270
88	0.04127	139.60%	1.3960	98.03533	0.01424	1.3960	25.29412	0.05519	(0.04095)	18.1310
89	0.04089	128.13%	1.2813	103.27899	0.01241	1.2813	25.29412	0.05066	(0.03825)	16.8497
90	0.04051	124.31%	1.2431	108.80312	0.01143	1.2431	25.29412	0.04915	(0.03772)	15.6066
91	0.04013	124.31%	1.2431	114.62271	0.01085	1.2431	25.29412	0.04915	(0.03830)	14.3635
92	0.03977	115.84%	1.1584	120.75358	0.00959	1.1584	25.29412	0.04580	(0.03620)	13.2051
93	0.03943	107.39%	1.0739	127.21238	0.00844	1.0739	25.29412	0.04246	(0.03401)	12.1312
94	0.03908	107.38%	1.0738	134.01664	0.00801	1.0738	25.29412	0.04245	(0.03444)	11.0574
95	0.03875	103.02%	1.0302	141.18484	0.00730	1.0302	25.29412	0.04073	(0.03343)	10.0272
96	0.03845	89.94%	0.8994	148.73645	0.00605	0.8994	25.29412	0.03556	(0.02951)	9.1278
97	0.03816	89.94%	0.8994	156.69198	0.00574	0.8994	25.29412	0.03556	(0.02982)	8.2284
98	0.03785	89.94%	0.8994	165.07303	0.00545	0.8994	25.29412	0.03556	(0.03011)	7.3290
99	0.03761	72.86%	0.7286	173.90236	0.00419	0.7286	25.29412	0.02881	(0.02462)	6.6004
100	0.03736	72.86%	0.7286	183.20394	0.00398	0.7286	25.29412	0.02881	(0.02483)	5.8718
101	0.03711	72.86%	0.7286	193.00304	0.00378	0.7286	25.29412	0.02881	(0.02503)	5.1432
102	0.03690	60.84%	0.6084	203.32628	0.00299	0.6084	25.29412	0.02405	(0.02106)	4.5348
103	0.03670	56.83%	0.5683	214.20167	0.00265	0.5683	25.29412	0.02247	(0.01981)	3.9665
104	0.03650	56.83%	0.5683	225.65876	0.00252	0.5683	25.29412	0.02247	(0.01995)	3.3982
105	0.03633	49.42%	0.4942	237.72867	0.00208	0.4942	25.29412	0.01954	(0.01746)	2.9040
106	0.03618	42.00%	0.4200	250.44416	0.00168	0.4200	25.29412	0.01660	(0.01493)	2.4840
107	0.03603	42.00%	0.4200	263.83976	0.00159	0.4200	25.29412	0.01660	(0.01501)	2.0640
108	0.03589	38.63%	0.3863	277.95187	0.00139	0.3863	25.29412	0.01527	(0.01388)	1.6777
109	0.03579	28.52%	0.2852	292.81879	0.00097	0.2852	25.29412	0.01128	(0.01030)	1.3925
110	0.03568	28.53%	0.2853	308.48091	0.00092	0.2853	25.29412	0.01128	(0.01035)	1.1072
111	0.03558	28.52%	0.2852	324.98075	0.00088	0.2852	25.29412	0.01128	(0.01040)	0.8220
112	0.03552	16.68%	0.1668	342.36313	0.00049	0.1668	25.29412	0.00659	(0.00611)	0.6552
113	0.03546	16.67%	0.1667	360.67525	0.00046	0.1667	25.29412	0.00659	(0.00613)	0.4885
114	0.03539	16.68%	0.1668	379.96683	0.00044	0.1668	25.29412	0.00659	(0.00616)	0.3217
115	0.03536	9.57%	0.0957	400.29027	0.00024	0.0957	25.29412	0.00378	(0.00354)	0.2260
116	0.03533	7.20%	0.0720	421.70076	0.00017	0.0720	25.29412	0.00285	(0.00268)	0.1540
		99.8460	99.8460							

PacifiCorp
Oregon Marginal Cost Study
Present Value of Cost of Dispersion Factor

Iowa Curve R 2 & 54 Year Average Life

Real Cost of Capital = 5.35%

YEAR	(A) PVCD	(B) % RENEWED	(C) NUM1	(D) DEM1	(E) NUM1/DEM1	(F) NUM2	(G) DEM2	(H) NUM2/DEM2	(I) INSTANCE	(J) Iowa R 2.0
	((A){yr-1} +(I)) / 100	((J,{yr-1})-(J)) * 100	(B)	1.0535 ^Year	(C) / (D)	(B)	1.0535 ^52	(F) / (G)	(E) - (H)	(Given)
										100.0000
1	0.00083	9.41%	0.0941	1.05349	0.08930	0.0941	15.02194	0.00626	0.08304	99.9059
2	0.00240	18.81%	0.1881	1.10984	0.16953	0.1881	15.02194	0.01252	0.15700	99.7178
3	0.00388	18.81%	0.1881	1.16920	0.16092	0.1881	15.02194	0.01252	0.14840	99.5296
4	0.00549	21.48%	0.2148	1.23174	0.17440	0.2148	15.02194	0.01430	0.16010	99.3148
5	0.00704	22.15%	0.2215	1.29762	0.17068	0.2215	15.02194	0.01474	0.15594	99.0933
6	0.00854	22.53%	0.2253	1.36702	0.16483	0.2253	15.02194	0.01500	0.14983	98.8680
7	0.01018	26.00%	0.2600	1.44014	0.18054	0.2600	15.02194	0.01731	0.16323	98.6080
8	0.01172	26.00%	0.2600	1.51717	0.17137	0.2600	15.02194	0.01731	0.15406	98.3480
9	0.01327	27.72%	0.2772	1.59832	0.17342	0.2772	15.02194	0.01845	0.15497	98.0708
10	0.01486	30.30%	0.3030	1.68381	0.17993	0.3030	15.02194	0.02017	0.15976	97.7679
11	0.01637	30.30%	0.3030	1.77387	0.17079	0.3030	15.02194	0.02017	0.15062	97.4649
12	0.01795	33.69%	0.3369	1.86875	0.18029	0.3369	15.02194	0.02243	0.15787	97.1280
13	0.01950	35.15%	0.3515	1.96871	0.17853	0.3515	15.02194	0.02340	0.15514	96.7765
14	0.02096	35.15%	0.3515	2.07401	0.16947	0.3515	15.02194	0.02340	0.14607	96.4250
15	0.02255	40.59%	0.4059	2.18494	0.18578	0.4059	15.02194	0.02702	0.15876	96.0191
16	0.02404	40.59%	0.4059	2.30181	0.17635	0.4059	15.02194	0.02702	0.14933	95.6131
17	0.02551	42.39%	0.4239	2.42493	0.17482	0.4239	15.02194	0.02822	0.14660	95.1892
18	0.02702	46.59%	0.4659	2.55463	0.18238	0.4659	15.02194	0.03102	0.15137	94.7233
19	0.02844	46.59%	0.4659	2.69127	0.17312	0.4659	15.02194	0.03102	0.14211	94.2574
20	0.02989	50.64%	0.5064	2.83522	0.17860	0.5064	15.02194	0.03371	0.14489	93.7510
21	0.03132	53.33%	0.5333	2.98687	0.17856	0.5333	15.02194	0.03550	0.14306	93.2177
22	0.03266	53.33%	0.5333	3.14663	0.16949	0.5333	15.02194	0.03550	0.13399	92.6843
23	0.03407	60.03%	0.6003	3.31493	0.18110	0.6003	15.02194	0.03996	0.14114	92.0840
24	0.03541	60.78%	0.6078	3.49224	0.17404	0.6078	15.02194	0.04046	0.13358	91.4762
25	0.03669	62.42%	0.6242	3.67903	0.16967	0.6242	15.02194	0.04155	0.12812	90.8520
26	0.03801	69.00%	0.6900	3.87582	0.17803	0.6900	15.02194	0.04593	0.13209	90.1620
27	0.03924	69.00%	0.6900	4.08312	0.16899	0.6900	15.02194	0.04593	0.12306	89.4720
28	0.04046	73.52%	0.7352	4.30152	0.17091	0.7352	15.02194	0.04894	0.12197	88.7368
29	0.04166	78.04%	0.7804	4.53160	0.17221	0.7804	15.02194	0.05195	0.12026	87.9564
30	0.04278	78.04%	0.7804	4.77398	0.16346	0.7804	15.02194	0.05195	0.11151	87.1761
31	0.04391	85.92%	0.8592	5.02933	0.17084	0.8592	15.02194	0.05720	0.11364	86.3169
32	0.04499	87.89%	0.8789	5.29833	0.16588	0.8789	15.02194	0.05851	0.10737	85.4380
33	0.04599	88.96%	0.8896	5.58173	0.15938	0.8896	15.02194	0.05922	0.10016	84.5484
34	0.04701	98.59%	0.9859	5.88028	0.16767	0.9859	15.02194	0.06563	0.10203	83.5625
35	0.04795	98.59%	0.9859	6.19480	0.15915	0.9859	15.02194	0.06563	0.09352	82.5766
36	0.04884	103.21%	1.0321	6.52614	0.15816	1.0321	15.02194	0.06871	0.08945	81.5444
37	0.04971	110.15%	1.1015	6.87521	0.16021	1.1015	15.02194	0.07332	0.08689	80.4429
38	0.05050	110.15%	1.1015	7.24295	0.15208	1.1015	15.02194	0.07332	0.07875	79.3414
39	0.05126	118.70%	1.1870	7.63035	0.15557	1.1870	15.02194	0.07902	0.07655	78.1544
40	0.05197	122.37%	1.2237	8.03848	0.15223	1.2237	15.02194	0.08146	0.07077	76.9307
41	0.05260	122.37%	1.2237	8.46844	0.14450	1.2237	15.02194	0.08146	0.06304	75.7070
42	0.05322	135.19%	1.3519	8.92139	0.15153	1.3519	15.02194	0.08999	0.06154	74.3551
43	0.05375	135.19%	1.3519	9.39857	0.14384	1.3519	15.02194	0.08999	0.05384	73.0033
44	0.05423	139.11%	1.3911	9.90128	0.14049	1.3911	15.02194	0.09260	0.04789	71.6122
45	0.05467	148.26%	1.4826	10.43087	0.14214	1.4826	15.02194	0.09870	0.04344	70.1296
46	0.05503	148.26%	1.4826	10.98879	0.13492	1.4826	15.02194	0.09870	0.03622	68.6470
47	0.05534	156.06%	1.5606	11.57656	0.13481	1.5606	15.02194	0.10389	0.03092	67.0864
48	0.05559	161.26%	1.6126	12.19576	0.13223	1.6126	15.02194	0.10735	0.02488	65.4739
49	0.05577	161.26%	1.6126	12.84807	0.12551	1.6126	15.02194	0.10735	0.01816	63.8613
50	0.05590	172.39%	1.7239	13.53529	0.12737	1.7239	15.02194	0.11476	0.01260	62.1373
51	0.05596	173.63%	1.7363	14.25925	0.12177	1.7363	15.02194	0.11558	0.00618	60.4010

52	0.05596	175.84%	1.7584	15.02194	0.11706	1.7584	15.02194	0.11706	-	58.6426
53	0.05589	184.70%	1.8470	15.82543	0.11671	1.8470	15.02194	0.12296	(0.00624)	56.7956
54	0.05577	184.70%	1.8470	16.67189	0.11079	1.8470	15.02194	0.12296	(0.01217)	54.9485
55	0.05559	189.22%	1.8922	17.56362	0.10774	1.8922	15.02194	0.12596	(0.01823)	53.0563
56	0.05535	193.74%	1.9374	18.50306	0.10471	1.9374	15.02194	0.12897	(0.02426)	51.1189
57	0.05505	193.74%	1.9374	19.49274	0.09939	1.9374	15.02194	0.12897	(0.02958)	49.1815
58	0.05470	198.69%	1.9869	20.53535	0.09675	1.9869	15.02194	0.13227	(0.03551)	47.1946
59	0.05429	199.93%	1.9993	21.63374	0.09241	1.9993	15.02194	0.13309	(0.04068)	45.1953
60	0.05384	200.18%	2.0018	22.79087	0.08783	2.0018	15.02194	0.13326	(0.04542)	43.1936
61	0.05333	202.44%	2.0244	24.00989	0.08432	2.0244	15.02194	0.13477	(0.05045)	41.1691
62	0.05278	202.44%	2.0244	25.29412	0.08004	2.0244	15.02194	0.13477	(0.05473)	39.1447
63	0.05220	201.75%	2.0175	26.64704	0.07571	2.0175	15.02194	0.13430	(0.05859)	37.1272
64	0.05158	200.70%	2.0070	28.07232	0.07150	2.0070	15.02194	0.13361	(0.06211)	35.1201
65	0.05092	200.70%	2.0070	29.57383	0.06787	2.0070	15.02194	0.13361	(0.06574)	33.1131
66	0.05024	196.19%	1.9619	31.15566	0.06297	1.9619	15.02194	0.13060	(0.06763)	31.1512
67	0.04954	194.26%	1.9426	32.82210	0.05919	1.9426	15.02194	0.12932	(0.07013)	29.2086
68	0.04881	194.26%	1.9426	34.57767	0.05618	1.9426	15.02194	0.12932	(0.07314)	27.2660
69	0.04809	183.22%	1.8322	36.42714	0.05030	1.8322	15.02194	0.12197	(0.07167)	25.4338
70	0.04735	183.22%	1.8322	38.37553	0.04774	1.8322	15.02194	0.12197	(0.07423)	23.6016
71	0.04660	178.67%	1.7867	40.42814	0.04419	1.7867	15.02194	0.11894	(0.07474)	21.8149
72	0.04588	168.04%	1.6804	42.59053	0.03945	1.6804	15.02194	0.11186	(0.07241)	20.1345
73	0.04514	168.04%	1.6804	44.86859	0.03745	1.6804	15.02194	0.11186	(0.07441)	18.4541
74	0.04442	156.99%	1.5699	47.26849	0.03321	1.5699	15.02194	0.10451	(0.07130)	16.8842
75	0.04373	149.63%	1.4963	49.79676	0.03005	1.4963	15.02194	0.09961	(0.06956)	15.3879
76	0.04302	149.63%	1.4963	52.46026	0.02852	1.4963	15.02194	0.09961	(0.07108)	13.8916
77	0.04238	131.30%	1.3130	55.26623	0.02376	1.3130	15.02194	0.08740	(0.06365)	12.5787
78	0.04174	129.26%	1.2926	58.22227	0.02220	1.2926	15.02194	0.08605	(0.06385)	11.2861
79	0.04111	125.06%	1.2506	61.33643	0.02039	1.2506	15.02194	0.08325	(0.06286)	10.0355
80	0.04056	108.26%	1.0826	64.61716	0.01675	1.0826	15.02194	0.07207	(0.05531)	8.9529
81	0.04000	108.26%	1.0826	68.07336	0.01590	1.0826	15.02194	0.07207	(0.05616)	7.8703
82	0.03948	97.98%	0.9798	71.71443	0.01366	0.9798	15.02194	0.06523	(0.05156)	6.8905
83	0.03902	87.70%	0.8770	75.55025	0.01161	0.8770	15.02194	0.05838	(0.04678)	6.0134
84	0.03854	87.70%	0.8770	79.59123	0.01102	0.8770	15.02194	0.05838	(0.04736)	5.1364
85	0.03815	72.27%	0.7227	83.84836	0.00862	0.7227	15.02194	0.04811	(0.03949)	4.4137
86	0.03777	68.41%	0.6841	88.33319	0.00774	0.6841	15.02194	0.04554	(0.03779)	3.7297
87	0.03740	66.62%	0.6662	93.05791	0.00716	0.6662	15.02194	0.04435	(0.03719)	3.0634
88	0.03711	50.56%	0.5056	98.03533	0.00516	0.5056	15.02194	0.03365	(0.02850)	2.5579
89	0.03682	50.56%	0.5056	103.27899	0.00490	0.5056	15.02194	0.03365	(0.02876)	2.0523
90	0.03657	44.07%	0.4407	108.80312	0.00405	0.4407	15.02194	0.02933	(0.02528)	1.6117
91	0.03637	34.33%	0.3433	114.62271	0.00300	0.3433	15.02194	0.02286	(0.01986)	1.2683
92	0.03617	34.33%	0.3433	120.75358	0.00284	0.3433	15.02194	0.02286	(0.02001)	0.9250
93	0.03603	24.35%	0.2435	127.21238	0.00191	0.2435	15.02194	0.01621	(0.01430)	0.6815
94	0.03591	20.07%	0.2007	134.01664	0.00150	0.2007	15.02194	0.01336	(0.01187)	0.4807
95	0.03579	20.07%	0.2007	141.18484	0.00142	0.2007	15.02194	0.01336	(0.01194)	0.2800
96	0.03574	8.67%	0.0867	148.73645	0.00058	0.0867	15.02194	0.00577	(0.00519)	0.1933
97	0.03569	8.67%	0.0867	156.69198	0.00055	0.0867	15.02194	0.00577	(0.00522)	0.1067
			99.8933	54.8956						

Depreciation

PACIFICORP
Remaining Life Depreciation Rates

[1] Account Number	[2] Description	[3] 6/30/2023 Balance	[4] IOWA CURVE	[5] Average Life	[6] NET SALVAGE Percent	[7] NET SALVAGE Amount	
		$		Yrs	%	$	
	TRANSMISSION PLANT						
350.20	Land Rights	282,573,177	R4	90.00	0.00%	-	
352.00	Structures & Improvements	386,384,736	R2.5	75.00	-5.00%	(19,319,237)	
353.00	Station Equipment	2,727,416,573	S0	60.00	-10.00%	(272,741,657)	
353.70	Supervisory Equipment	-				-	
354.00	Towers & Fixtures	1,526,005,036	R4	72.00	-8.00%	(122,080,403)	
355.00	Poles & Fixtures	1,278,838,555	R2.5	62.00	-40.00%	(511,535,422)	
356.00	OH Conductors & Devices	1,676,119,586	R2.5	68.00	-30.00%	(502,835,876)	
356.20	Clearing	-				-	
357.00	UG Conduit	3,872,987	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	12,141,468	R5	75.00	0.00%	-	
	Total Transmission Plant	7,902,432,736		65.40	-18.08%	(1,428,966,626)	
				Use 65 Years			65
	TRANSMISSION PLANT excludes land accounts						
352.00	Structures & Improvements	386,384,736	2.50	5.07%	0.13		
353.00	Station Equipment	2,727,416,573	-	35.79%	-		
353.70	Supervisory Equipment	-		0.00%	-		
354.00	Towers & Fixtures	1,526,005,036	4.00	20.03%	0.80		
355.00	Poles & Fixtures	1,278,838,555	2.50	16.78%	0.42		
356.00	OH Conductors & Devices	1,676,119,586	2.50	22.00%	0.55		
356.20	Clearing	-	-	0.00%	-		
357.00	UG Conduit	3,872,987	2.50	0.05%	0.00		
358.00	UG Conductors & Devices	9,080,617	2.50	0.12%	0.00		
359.00	Roads & Trails	12,141,468	5.00	0.16%	0.01		
	Total Transmission Plant	7,619,859,559		100.00%	1.91	**Use R 2**	

[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	6,441,896	S1.5	70.00	0.00%	-	
361.00	Structures & Improvements	35,033,648	R2	67.00	-10.00%	(3,503,365)	
362.00	Station Equipment	306,033,063	R1	53.00	-20.00%	(61,206,613)	
362.70	Supervisory & Alarm Equipment					-	
364.00	Poles, Towers & Fixtures	516,891,491	R1	58.00	-100.00%	(516,891,491)	
365.00	OH Conductors & Devices	325,012,527	R1	65.00	-50.00%	(162,506,263)	
366.00	UG Conduit	120,810,576	R3	75.00	-45.00%	(54,364,759)	
367.00	UG Conductors & Devices	235,065,979	R2.5	60.00	-35.00%	(82,273,093)	
368.00	Line Transformers	532,450,677	R1.5	46.00	-25.00%	(133,112,669)	
369.10	Overhead Services	117,296,138	R2	60.00	-35.00%	(41,053,648)	
369.20	Underground Services	242,221,216	R4	60.00	-40.00%	(96,888,486)	
370.00	Meters	105,898,473	S3	20.00	-3.00%	(3,176,954)	
371.00	I.O.C.P.	2,685,798	L0	27.00	-50.00%	(1,342,899)	
373.00	Street Lighting & Signal Systems	25,130,359	R1	45.00	-30.00%	(7,539,108)	
	Total OREGON Distribution Plant	2,570,971,841		53.60	-45.27%	(1,163,859,348)	
				Use 54 years			54

	DISTRIBUTION PLANT excludes land accounts (OREGON)					
361.00	Structures & Improvements	35,033,648	2.00	1.37%	0.03	
362.00	Station Equipment	306,033,063	1.00	11.93%	0.12	
362.70	Supervisory & Alarm Equipment	-		0.00%	-	
364.00	Poles, Towers & Fixtures	516,891,491	1.00	20.16%	0.20	
365.00	OH Conductors & Devices	325,012,527	1.00	12.67%	0.13	
366.00	UG Conduit	120,810,576	3.00	4.71%	0.14	
367.00	UG Conductors & Devices	235,065,979	2.50	9.17%	0.23	
368.00	Line Transformers	532,450,677	1.50	20.76%	0.31	
369.10	Overhead Services	117,296,138	2.00	4.57%	0.09	
369.20	Underground Services	242,221,216	4.00	9.45%	0.38	
370.00	Meters	105,898,473	3.00	4.13%	0.12	
371.00	I.O.C.P.	2,685,798	-	0.10%	-	
373.00	Street Lighting & Signal Systems	25,130,359	1.00	0.98%	0.01	
	Total OREGON Distribution Plant	2,564,529,945		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

Cust

PacifiCorp
Oregon Marginal Cost Study
Customers and MWh @ Sales

			12 Months Ended June 30, 2023 - Actual									12 Months Ended December 2025 - Normalized	
		(A)	(B)	(C)	(D)	(E)	(F)	(G)				(H)	(I)
Line	Description	Del. Volt	Average Customers	% Total Class	Annual MWh's	% Total Class	Average Billing kW	% Total Class	Three Phase Customers	Three Phase % of Customers	Single Phase % of Customers	Average Customers	Annual MWh's
1	Res - Schedule 4	(sec)	533,013	100.00%	5,814,272	100.00%	5,042,753	100.00%	-	0.00%	100.00%	513,581	5,787,620
2													
3	GS - Schedule 23												
4	0-15 kW	(sec)	71,109	82.43%	586,948	47.87%	947,994	63.89%	13,677	19.23%	80.77%	70,880	555,432
5	15+ kW	(sec)	15,152	17.57%	639,141	52.13%	535,908	36.11%	6,937	45.78%	54.22%	15,103	604,823
6	Sec Subtotal		86,261	100.00%	1,226,089	100.00%	1,483,903	100.00%	20,614	23.90%	76.10%	85,983	1,160,255
7	Primary	(pri)	50		1,955		11,400		50	99.38%	0.62%	50	1,877
8	Total		86,312		1,228,044		1,495,302		20,664	23.94%	76.06%	86,033	1,162,132
9													
10	GS - Schedule 28												
11	0-50 kW	(sec)	4,543	43.68%	434,116	20.82%	191,574	17.93%	3,213	70.73%	29.27%	4,630	425,310
12	51-100 kW	(sec)	3,614	34.75%	669,847	32.12%	390,191	36.52%	3,086	85.40%	14.60%	3,683	656,260
13	100 + kW	(sec)	2,243	21.57%	981,603	47.07%	486,664	45.55%	2,187	97.52%	2.48%	2,286	961,692
14	Sec Subtotal		10,399	100.00%	2,085,566	100.00%	1,068,429	100.00%	8,486	81.60%	18.40%	10,599	2,043,261
15	Primary	(pri)	59		21,809		39,149		59	100.79%	-0.79%	59	21,451
16	Total		10,458		2,107,374		1,107,578		8,545	81.71%	18.29%	10,658	2,064,712
17													
18	GS - Schedule 30												
19	0-300 kW	(sec)	198	24.84%	170,220	13.63%	55,540	14.73%	198	99.58%	0.42%	200	170,668
20	300+ kW	(sec)	600	75.16%	1,078,967	86.37%	321,463	85.27%	600	99.94%	0.06%	606	1,081,806
21	Sec Subtotal		799	100.00%	1,249,187	100.00%	377,003	100.00%	798	99.85%	0.15%	806	1,252,474
22	Primary	(pri)	40		76,532		53,025		40	98.94%	1.06%	41	77,805
23	Total		839		1,325,719		430,028		838	99.81%	0.19%	847	1,330,279
24													
25	LPS - Schedule 48												
26	1 - 4 MW	(sec)	81	95.25%	456,583	79.89%	105,438	80.15%	81	100.60%	-0.60%	82	456,088
27	> 4 MW	(sec)	4	4.75%	114,945	20.11%	26,117	19.85%	4	99.59%	0.41%	4	114,820
28	Sec Subtotal		85	100.00%	571,528	100.00%	131,555	100.00%	85	100.56%	-0.56%	86	570,908
29	1 - 4 MW	(pri)	58	70.69%	509,238	37.74%	114,319	42.43%	58	99.85%	0.15%	59	819,472
30	> 4 MW	(pri)	24	29.31%	840,070	62.26%	155,107	57.57%	24	99.63%	0.37%	25	1,351,851
31	Pri Subtotal		82	100.00%	1,349,307	100.00%	269,427	100.00%	82	99.78%	0.22%	84	2,171,323
32	Trans	(trn)	7		1,156,897		317,201		7	101.08%	-1.08%	8	1,934,880
33	Total		174		3,077,732		718,183		174	100.21%	-0.21%	178	4,677,111
34													
35	Irrigation - Schedule 41 (Average)	(sec)	3,353	100.00%	196,326	100.00%	186,770	100.00%		0.00%	100.00%	3,311	234,910
36													
37	Irrigation - Schedule 41 (Annual)	(sec)	6,149						5,184	84.30%	15.70%	7,887	234,910
38													
39	PS&H - Schedule 15	(sec)	5,991	79.08%	2,159	10.47%	-	0.00%	-			5,833	2,128
40	PS&H - Schedule 51	(sec)	1,194	15.76%	8,930	43.32%	-	0.00%	-			1,210	7,898
41	PS&H - Schedule 53	(sec)	294	3.88%	8,075	39.17%	2,050	23.08%	-			296	8,821
42	PS&H - Schedule 54	(sec)	98	1.29%	1,450	7.03%	6,832	76.92%	-			98	1,374
43	Total		7,577	100.00%	20,614	100.00%	8,881	100.00%				7,437	20,221

MW

PacifiCorp
Oregon Marginal Cost Study
Cutomer Loads at Sales - MW
12 Months Ended December 2025

		(A) (B)	(C) (D)		(E)	(F)	(G)	(H)
Line	Description	Del. Volt	System Peak	Distribution Peak	Non-Coincident Peak	Cust per Transformer	Coincidence Factor for Winter Loads	Weighted Transformer Peak
1	Res - Schedule 4	(sec)	1,021	1,213	5,043	4	0.67	3,379
2								
3	GS - Schedule 23							
4	0-15 kW	(sec)	85	90	948	2	0.77	730
5	15+ kW	(sec)	91	98	536	2	0.77	413
6	Primary	(pri)	0	0	11	1	1.00	11
7								
8	GS - Schedule 28							
9	0-50 kW	(sec)	65	70	192	1	1.00	192
10	51-100 kW	(sec)	99	104	390	1	1.00	390
11	100 + kW	(sec)	141	147	487	1	1.00	487
12	Primary	(pri)	3	3	39	1	1.00	39
13								
14	GS - Schedule 30							
15	0-300 kW	(sec)	25	26	56	2	0.77	43
16	300+ kW	(sec)	153	158	321	2	0.77	248
17	Primary	(pri)	11	11	53	1	1.00	53
18								
19	LPS - Schedule 48							
20	1 - 4 MW	(sec)	63	64	105	1	1.00	105
21	1 - 4 MW	(pri)	70	72	114	1	1.00	114
22	> 4 MW	(sec)	14	14	26	1	1.00	26
23	> 4 MW	(pri)	204	208	155	1	1.00	155
24	Trans	(trn)	222	228	317	1	1.00	317
25								
26	Irrigation - Sch 41	(sec)	31	47	187	1	1.00	187
27								
28	Sch 15	(sec)	0	0	0	1	1.00	0
29	Sch 51	(sec)	0	0	2	1	1.00	2
30	Customer-Owned Lighting - Sch 53	(sec)	0	0	2	1	1.00	2
31	Rec Field Lighting - Sch 54	(sec)	0	0	7	1	1.00	7

DistPeak

PacifiCorp
Oregon Marginal Cost Study
Weighted Distribution Peaks
Tied to December 2023 Forecast

A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
		Jul-22 29 17:00	Aug-22 25 17:00	Sep-22 1 17:00	Oct-22 27 08:00	Nov-22 17 09:00	Dec-22 16 09:00	Jan-23 30 08:00	Feb-23 1 08:00	Mar-23 16 07:00	Apr-23 4 07:00	May-23 17 18:00	Jun-23 29 16:00	Sum of 12 Wgt Dist peaks
	Del. Volt													
Res - Schedule 4	(sec)	289.4	176.0	15.2	2.3	16.1	91.4	151.5	133.6	26.3	16.2	12.4	282.5	1,213.0
GS - Schedule 23														
0-15 kW	(sec)	20.7	13.9	1.3	0.2	1.2	6.7	9.4	9.3	2.0	1.2	0.9	23.6	90.4
15+ kW	(sec)	23.1	15.0	1.3	0.3	1.5	8.3	10.4	10.1	2.2	1.3	1.0	23.1	97.6
Primary	(pri)	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.3
GS - Schedule 28														
0-50 kW	(sec)	16.7	10.6	1.0	0.2	1.0	4.9	7.2	7.1	1.5	0.9	0.7	17.8	69.6
51-100 kW	(sec)	25.5	16.7	1.5	0.2	1.5	7.6	10.7	10.8	2.4	1.3	1.1	24.9	104.3
100+ kW	(sec)	32.7	22.6	1.9	0.4	2.3	11.9	16.6	16.7	3.7	2.1	1.5	34.0	146.5
Primary	(pri)	0.7	0.5	0.0	0.0	0.1	0.3	0.4	0.3	0.1	0.1	0.0	0.7	3.1
GS - Schedule 30														
0-300 kW	(sec)	5.6	4.1	0.3	0.1	0.4	2.0	2.9	2.9	0.7	0.4	0.3	6.4	26.1
300+ kW	(sec)	33.2	24.4	2.1	0.5	2.8	13.1	17.5	17.6	4.3	2.5	1.6	38.1	157.8
Primary	(pri)	2.5	1.7	0.1	0.0	0.2	0.9	1.3	1.2	0.3	0.2	0.1	2.5	11.0
LPS - Schedule 48														
1 - 4 MW	(sec)	14.3	10.2	0.9	0.2	1.2	5.9	6.5	7.4	1.8	1.1	0.6	13.4	63.7
1 - 4 MW	(pri)	16.2	11.7	1.1	0.2	1.3	6.2	7.1	7.3	1.9	1.1	0.8	16.7	71.8
> 4 MW	(sec)	2.9	2.5	0.2	0.0	0.3	1.4	1.4	1.5	0.4	0.2	0.2	3.5	14.4
> 4 MW	(pri)	42.3	36.4	3.0	0.6	3.7	19.7	19.7	21.9	5.1	3.0	2.6	49.9	207.9
Trans	(trn)	49.9	38.2	3.3	0.7	3.9	19.0	21.9	26.3	5.7	3.3	2.5	53.3	227.9
Irrigation - Sch 41	(sec)	15.9	10.4	0.8	0.0	0.0	0.1	0.2	0.2	0.1	0.3	0.6	18.2	47.0
Customer-Owned Lighting - Sch 53		-	-	-	-	-	-	-	-	-	-	-	-	-
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	0.1

PacifiCorp
Oregon Marginal Cost Study
Distribution Peaks @ Sales - MW
Tied to December 2023 Forecast

A	B	C	D	E	F	G	H	I	J	K	L	M	N
		Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23
		29	25	1	27	17	16	30	1	16	4	17	29
		17:00	17:00	17:00	08:00	09:00	09:00	08:00	08:00	07:00	07:00	18:00	16:00
	Del. Volt												
Res - Schedule 4	(sec)	1,366.2	1,113.0	1,122.3	827.0	997.8	1,131.4	1,390.7	1,159.8	969.3	1,039.9	1,037.3	1,187.7
GS - Schedule 23													
0-15 kW	(sec)	97.8	88.2	92.4	70.3	74.8	82.3	86.1	81.0	73.6	73.9	78.2	99.2
15+ kW	(sec)	109.1	95.1	94.0	99.3	90.7	103.3	95.3	87.6	81.4	83.3	84.8	97.1
Primary	(pri)	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
GS - Schedule 28													
0-50 kW	(sec)	79.0	66.9	72.1	55.4	59.1	60.8	66.2	61.4	56.7	55.1	60.5	75.0
51-100 kW	(sec)	120.5	105.7	108.3	84.1	89.7	94.4	98.6	93.4	86.8	84.9	93.8	104.9
100+ kW	(sec)	154.6	142.8	141.9	131.3	141.5	147.2	152.7	145.1	136.9	135.0	125.1	143.1
Primary	(pri)	3.5	3.2	2.9	3.0	3.1	3.1	3.4	3.0	3.0	3.2	2.4	2.8
GS - Schedule 30													
0-300 kW	(sec)	26.5	26.0	25.2	25.4	26.3	24.7	27.0	25.0	25.1	24.8	22.9	27.0
300+ kW	(sec)	156.6	154.4	154.8	168.9	174.4	162.4	160.8	153.1	157.5	162.7	135.7	160.2
Primary	(pri)	12.0	11.0	10.1	12.7	11.5	10.8	11.6	10.4	10.9	11.9	11.4	10.4
LPS - Schedule 48													
1 - 4 MW	(sec)	67.7	64.7	68.1	76.7	76.2	72.7	59.7	64.4	66.0	72.7	53.0	56.3
1 - 4 MW	(pri)	76.6	74.3	80.7	79.4	80.5	76.3	65.3	63.5	71.0	73.6	69.3	70.2
> 4 MW	(sec)	13.8	16.0	15.3	15.3	15.8	16.9	12.5	13.2	13.1	13.5	14.9	14.6
> 4 MW	(pri)	199.6	230.4	220.4	220.5	227.8	243.5	180.5	190.5	188.5	194.1	214.2	209.8
Trans	(trn)	235.5	241.7	239.8	248.7	239.7	235.4	201.4	228.4	208.8	210.3	209.9	224.0
Irrigation - Sch 41	(sec)	75.0	65.9	60.3	12.3	1.3	1.8	1.9	1.9	3.9	17.2	51.0	76.6
Customer-Owned Lighting - Sch 53		-	-	-	-	-	-	-	-	-	-	-	-
Rec Field Lighting - Sch 54		0.0	0.0	0.1	0.0	0.0	0.1	0.2	0.1	0.0	0.0	0.0	0.0

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		
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	Peak Month	Peak Load
Agness Avenue		18,730	17,702	17,782	14,474	15,790	16,098	16,165	15,579	16,119	14,036	13,946	20,002	Jun-21	20,002
Albina		21,282	21,405	21,346	19,076	23,551	19,109	19,045	18,950	18,043	17,427	17,422	23,099	Nov-20	23,551
Alderwood		22,900	23,067	23,162	19,715	17,045	17,654	17,762	18,121	17,295	18,930	19,315	26,041	Jun-21	26,041
Applegate		10,900	10,470	10,266	10,255	12,312	12,825	11,914	11,678	11,350	9,900	8,234	11,408	Dec-20	12,825
Ashland		16,220	16,296	15,674	12,122	14,871	15,139	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		19,563	19,148	19,289	14,464	15,861	15,529	16,158	15,731	14,691	13,261	14,400	20,457	Jun-21	20,457
Belknap		29,469	29,666	30,457	22,319	23,748	24,265	22,529	25,572	24,398	20,554	22,878	32,660	Jun-21	32,660
Bend Plant		19,088	16,941	18,159	14,043	14,410	15,675	15,946	16,759	12,161	10,786	11,937	22,252	Jun-21	22,252
Bloss		10,495	10,809	11,249	10,883	11,757	11,748	10,961	11,643	11,843	10,348	11,520	10,166	Mar-21	11,843
REDACTED		909	893	864	889	895	951	955	963	909	934	881	917	Feb-21	963
Bond Street		15,715	14,197	14,817	13,883	13,082	14,410	14,436	14,676	12,868	11,456	10,896	21,809	Jun-21	21,809
Brookhurst		37,627	38,057	37,161	24,292	26,085	28,163	25,827	28,770	28,093	23,991	30,550	41,875	Jun-21	41,875
Bryant		24,090	23,242	23,674	17,912	19,387	20,624	23,093	21,162	26,013	16,098	18,520	28,149	Jun-21	28,149
Buchanan		22,991	21,402	22,894	22,535	22,997	23,321	25,550	24,844	21,769	20,507	17,384	27,920	Jun-21	27,920
Buckaroo		24,425	23,070	20,376	20,859	17,284	18,639	18,210	19,455	16,798	15,532	16,967	26,368	Jun-21	26,368
Calapooya		5,543	5,533	5,531	5,289	5,460	5,755	5,612	5,539	5,283	4,999	4,504	6,001	Jun-21	6,001
Campbell		24,446	24,035	24,701	22,343	23,055	16,416	16,446	15,361	14,501	12,852	16,618	23,289	Sep-20	24,701
Cannon Beach		4,867	4,462	4,700	6,926	6,957	6,988	7,146	7,010	6,733	6,503	4,860	4,455	Jan-21	7,146
Canyonville		7,502	7,628	7,135	7,217	7,385	7,933	8,117	7,588	7,976	7,858	6,552	8,218	Jun-21	8,218
Casebeer		7,686	7,295	5,609	3,682	2,903	3,115	3,219	2,989	2,946	5,731	7,834	8,662	Jun-21	8,662
Cave Junction		13,336	12,650	13,309	15,296	16,778	17,359	17,939	17,316	18,383	15,749	12,370	14,339	Mar-21	18,383
Caveman		20,812	18,927	19,818	13,966	14,715	15,328	15,173	14,022	14,739	14,490	14,059	21,698	Jun-21	21,698
Cherry Lane		7,551	7,536	7,387	7,616	7,315	7,379	7,419	7,322	7,406	7,539	7,309	7,279	Oct-20	7,616
Chiloquin		7,367	7,303	8,134	7,380	7,453	6,707	7,313	7,568	7,654	7,944	7,913	7,640	Sep-20	8,134
China Hat		19,383	17,479	17,722	20,198	19,688	20,417	21,448	21,612	19,636	18,433	15,643	22,708	Jun-21	22,708
Circle Blvd		18,197	15,621	15,477	15,033	14,308	13,678	14,351	14,139	14,423	14,919	14,997	17,387	Jul-20	18,197
Cleveland Ave.		23,797	17,871	31,685	29,342	28,728	29,114	30,657	29,078	19,266	28,592	26,808	37,967	Jun-21	37,967
Cloake		15,790	15,891	15,315	10,331	10,961	11,405	11,494	10,295	10,943	9,311	11,626	17,983	Jun-21	17,983
Coburg		2,421	2,337	2,287	1,808	1,868	2,064	1,978	1,957	1,785	1,646	1,613	2,669	Jun-21	2,669
Columbia		32,170	31,717	29,073	27,566	27,966	29,638	30,187	30,301	28,585	27,152	25,723	33,519	Jun-21	33,519
Coquille		10,738	11,026	11,070	15,003	15,983	16,600	16,114	15,832	15,843	15,378	12,258	13,734	Dec-20	16,600
Cully		16,959	15,050	15,493	11,608	12,696	13,956	16,748	14,955	11,948	8,514	8,849	14,783	Jul-20	16,959
Culver		7,937	6,797	6,359	7,362	8,989	8,286	8,733	8,676	7,561	6,677	6,258	8,642	Nov-20	8,989
Dairy		10,746	8,546	6,609	4,092	2,778	2,863	2,715	2,599	2,667	6,904	8,937	10,113	Jul-20	10,746
Dallas		33,210	32,488	32,656	29,034	32,177	34,353	32,569	34,426	32,147	29,580	26,016	39,591	Jun-21	39,591
Dalreed		53,302	56,191	46,640	21,494	8,287	7,941	8,926	8,091	21,448	28,174	44,570	52,844	Aug-20	56,191
Deschutes		8,265	7,343	7,406	10,982	9,998	11,562	12,035	12,116	10,548	8,916	6,886	9,433	Feb-21	12,116
Devils Lake		20,257	19,422	20,008	28,083	29,641	31,539	32,217	32,116	30,833	28,233	22,730	20,932	Jan-21	32,217

Dixon	3,383	3,117	3,375	2,490	2,304	2,436	2,458	2,509	2,166	2,327	2,468	3,575	Jun-21	3,575
Dodge Bridge	11,371	11,622	11,046	10,055	11,199	13,422	10,668	16,425	10,813	9,246	9,015	12,466	Feb-21	16,425
Dowell	16,290	16,092	15,468	10,518	12,173	12,729	12,185	11,480	11,890	9,861	12,452	17,655	Jun-21	17,655
Easy Valley	19,935	20,730	18,603	14,098	16,809	17,194	16,738	15,759	16,084	13,081	14,942	22,436	Jun-21	22,436
Empire	9,962	8,833	10,420	15,387	17,404	18,610	18,370	18,710	17,895	16,370	12,185	10,479	Feb-21	18,710
Fern Hill	1,812	1,847	2,068	2,794	3,293	3,309	3,362	3,889	2,539	2,400	1,544	1,417	Feb-21	3,889
Fielder Creek	11,024	10,498	10,417	11,372	11,527	11,794	12,164	11,416	12,085	10,819	8,260	12,117	Jan-21	12,164
Foothills Rd	13,928	13,810	13,848	10,034	8,855	11,263	11,122	10,875	9,746	8,989	11,674	15,529	Jun-21	15,529
Garden Valley	14,841	12,336	14,480	10,888	10,633	10,592	10,310	9,553	10,165	9,181	11,120	16,317	Jun-21	16,317
Glendale	9,818	9,816	9,275	12,291	11,926	12,249	11,734	11,736	11,684	11,373	10,549	11,703	Oct-20	12,291
Gold Hill	8,164	8,088	7,907	7,008	8,035	8,496	7,882	7,675	7,629	6,715	6,547	8,668	Jun-21	8,668
Gordon Hollow	4,585	4,032	3,799	3,755	3,533	3,956	3,848	4,690	3,536	3,259	3,250	4,489	Feb-21	4,690
Goshen	5,613	5,600	5,347	5,848	5,672	6,356	6,309	6,143	5,768	5,463	4,155	6,258	Dec-20	6,356
Grant Street	24,072	24,817	24,947	22,661	25,315	26,565	29,174	28,523	23,985	21,096	21,475	28,826	Jan-21	29,174
Green	14,435	14,243	14,093	12,789	13,179	13,682	13,922	12,465	13,470	11,947	11,092	15,604	Jun-21	15,604
Harrisburg	8,308	7,305	7,374	7,680	8,051	8,741	8,538	8,432	8,423	7,104	5,710	8,485	Dec-20	8,741
Hazelwood	7,296	7,303	7,129	6,509	6,530	6,686	6,747	6,581	6,412	5,583	4,804	7,681	Jun-21	7,681
Hillview	28,199	24,717	29,902	23,168	24,427	25,185	23,912	24,989	24,936	20,954	20,670	31,463	Jun-21	31,463
Holladay	22,638	21,269	21,060	18,559	17,270	18,078	18,619	18,787	16,240	16,627	15,606	21,230	Jul-20	22,638
Hollywood	31,334	30,111	30,065	22,562	24,372	25,857	24,136	29,650	24,040	23,818	22,364	35,974	Jun-21	35,974
Hood River	29,865	28,567	28,247	25,171	24,399	31,263	26,571	30,603	24,427	21,559	22,183	35,540	Jun-21	35,540
Hornet	15,063	15,749	15,327	11,174	11,274	11,874	10,749	11,078	11,302	9,782	12,038	17,381	Jun-21	17,381
Independence	21,249	20,788	20,746	16,646	16,983	17,870	18,428	18,988	17,258	15,311	16,531	23,969	Jun-21	23,969

Jacksonville	17,658	18,271	17,233	12,144	14,496	15,086	15,130	14,651	14,060	11,879	13,446	20,264	Jun-21	20,264
Jefferson	8,957	8,992	9,194	9,866	10,418	10,763	10,812	11,209	11,031	10,119	9,887	11,758	Jun-21	11,758
Jerome Prairie	13,395	13,402	12,613	13,363	15,930	15,742	14,381	14,854	15,015	12,636	10,978	15,843	Nov-20	15,930
Junction City	8,095	8,288	8,096	8,179	8,647	9,228	8,821	8,988	8,615	7,580	6,394	8,346	Dec-20	9,228
Killingsworth	23,499	22,569	20,594	23,354	23,812	23,557	24,256	25,179	22,303	12,947	11,630	20,470	Feb-21	25,179
Knappa Svensen	2,828	2,943	2,847	3,971	4,381	4,500	5,097	4,934	4,703	4,397	3,074	3,471	Jan-21	5,097
Knott	19,580	19,552	19,282	21,210	22,420	23,845	28,965	28,967	24,193	21,484	19,631	31,719	Jun-21	31,719
Lakeport	17,545	17,584	18,155	17,502	18,414	18,695	19,825	19,264	19,102	17,296	16,407	18,452	Jan-21	19,825
Lancaster	8,022	7,850	7,845	6,892	7,556	6,861	9,051	8,785	8,555	7,510	6,140	7,015	Jan-21	9,051
Lebanon	30,414	30,909	29,185	27,620	27,547	29,718	28,491	29,369	26,880	25,003	23,760	35,795	Jun-21	35,795
Lincoln	19,472	19,650	18,878	19,108	18,901	19,048	18,885	21,055	18,625	17,424	16,173	22,534	Jun-21	22,534
Lockhart	11,476	14,458	11,512	17,954	20,180	21,837	21,351	21,406	21,756	20,086	14,491	12,029	Dec-20	21,837
Lyons	18,342	18,142	16,978	18,222	19,639	19,794	20,354	19,864	19,953	19,209	17,797	18,398	Jan-21	20,354
Madras	18,690	16,568	16,737	17,805	17,372	18,453	19,533	20,259	16,828	16,462	14,419	21,583	Jun-21	21,583
Mallory	13,639	12,923	12,581	10,176	11,245	11,806	12,392	13,812	10,625	9,363	8,811	15,226	Jun-21	15,226
Marys River	14,668	13,583	14,294	14,584	14,753	15,119	15,080	15,022	14,225	13,120	12,231	14,792	Dec-20	15,119
Medford	24,526	24,011	24,566	18,541	17,154	18,434	18,304	17,677	16,034	16,395	19,167	27,686	Jun-21	27,686
Merlin	23,152	22,909	22,847	25,141	27,216	28,403	29,137	25,571	29,699	21,676	19,455	25,716	Mar-21	29,699
Merrill	8,824	8,612	8,147	4,375	4,773	4,854	5,112	4,867	4,796	6,308	7,109	9,355	Jun-21	9,355
Mile High	10,108	9,485	10,286	11,120	11,763	12,708	12,593	12,648	12,555	11,190	10,229	10,563	Dec-20	12,708
Murder Creek	41,616	58,603	51,206	46,686	47,405	51,125	50,902	48,828	45,494	44,449	42,305	55,784	Aug-20	58,603
Oak Knoll	19,300	19,169	18,208	14,870	18,395	19,241	19,892	19,749	18,818	14,449	14,256	22,700	Jun-21	22,700
O'Brien	1,384	1,257	1,243	1,417	1,518	1,646	1,630	1,554	1,661	1,428	1,188	1,395	Mar-21	1,661
REDACTED	23,526	27,074	27,562	22,689	22,040	21,948	19,207	18,655	18,344	15,939	14,935	19,730	Sep-20	27,562
Overpass	36,882	36,533	34,648	34,570	33,884	36,105	36,946	37,699	34,284	26,986	29,935	38,263	Jun-21	38,263
Pallette	353	349	295	417	477	465	465	486	407	416	292	453	Feb-21	486
Park Street	33,117	31,630	31,935	22,481	25,656	27,997	26,418	25,256	25,788	21,343	22,736	34,659	Jun-21	34,659
Parkrose	27,509	28,524	27,154	23,633	25,161	26,563	27,978	31,467	24,964	22,422	21,327	33,225	Jun-21	33,225
Pendleton	30,942	28,440	25,080	18,690	19,712	21,383	21,170	23,806	21,160	21,770	19,154	33,400	Jun-21	33,400
Pilot Butte	18,542	16,398	17,002	13,898	13,585	15,086	14,639	15,193	12,602	11,359	12,370	20,739	Jun-21	20,739
Prineville	35,527	35,207	32,901	23,824	32,702	36,450	40,005	35,670	32,138	31,935	29,234	40,843	Jun-21	40,843
Prospect Central	2,189	2,408	3,144	1,868	4,311	5,147	5,304	5,530	3,134	4,523	3,695	2,194	Feb-21	5,530
Queen Ave	36,131	35,932	36,236	26,041	28,377	31,084	32,023	31,063	27,641	25,452	28,156	42,219	Jun-21	42,219
Redmond 115	37,865	36,811	35,176	35,879	33,204	37,260	38,675	36,886	33,347	31,827	26,933	41,483	Jun-21	41,483
Riddle	17,437	15,808	15,011	17,230	17,790	16,244	17,612	17,380	17,711	15,911	13,479	17,507	Nov-20	17,790
REDACTED	11,366	11,091	11,159	11,563	11,213	11,862	11,683	11,665	12,016	12,137	11,670	11,478	Apr-21	12,137
Roseburg	22,614	21,815	21,701	19,499	20,560	20,820	21,252	20,133	20,499	17,668	15,119	24,846	Jun-21	24,846
Ross Ave	7,199	6,993	7,159	5,379	5,623	6,080	6,528	6,028	6,041	5,010	5,390	7,995	Jun-21	7,995
Roxy Ann	15,252	15,494	16,024	9,377	7,867	7,982	8,175	7,207	6,849	6,306	11,396	16,977	Jun-21	16,977
Russelville	28,472	28,202	27,605	24,581	26,687	28,242	29,765	33,495	25,502	23,010	22,229	33,803	Jun-21	33,803
Sage Road	31,627	31,030	31,720	24,004	23,852	28,937	29,179	24,214	22,422	21,262	22,690	34,005	Jun-21	34,005
Scenic	28,959	29,133	28,859	19,245	19,577	21,459	20,016	19,793	18,625	15,803	23,723	32,058	Jun-21	32,058
Scio	5,137	5,332	5,171	5,118	5,339	5,576	5,326	5,361	5,235	4,891	4,263	5,833	Jun-21	5,833
Seaside	15,101	15,040	15,752	18,082	19,829	21,204	21,638	21,131	19,452	18,506	14,816	14,955	Jan-21	21,638
Shevlin Park	23,274	20,265	22,070	16,466	16,973	18,659	18,814	19,343	15,501	13,989	14,751	28,007	Jun-21	28,007
Southgate	13,786	14,482	14,313	12,871	13,367	12,998	14,371	12,762	13,554	12,122	10,919	17,030	Jun-21	17,030
State Street	18,366	18,603	19,309	27,295	31,675	33,886	33,119	32,046	32,628	29,156	23,766	19,005	Dec-20	33,886
Stayton	33,538	33,866	32,063	31,038	31,469	33,886	32,756	32,307	31,694	29,172	25,167	40,815	Jun-21	40,815

Stevens Road	22,961	23,777	22,361	13,961	16,268	17,769	18,383	18,097	15,502	12,876	18,932	26,945	Jun-21	26,945
Sutherlin	11,549	11,616	11,257	11,421	11,730	11,288	11,675	11,207	11,075	10,317	8,283	13,088	Jun-21	13,088
Sweet Home	22,385	22,268	21,916	25,370	25,583	25,283	24,438	24,361	24,388	22,327	17,081	26,191	Jun-21	26,191
Takelma	8,921	9,235	8,463	8,727	9,950	10,876	10,090	10,544	9,510	8,490	6,929	10,272	Dec-20	10,876
Talent	22,760	22,288	22,651	14,851	18,005	19,046	18,624	18,066	16,736	13,997	14,539	20,947	Jul-20	22,760
Texum	12,305	11,181	12,033	11,379	11,348	12,628	15,313	15,053	11,806	10,042	8,891	12,405	Jan-21	15,313
Umatilla	14,925	14,016	13,252	10,117	9,466	10,410	14,100	14,390	9,464	9,193	12,289	16,055	Jun-21	16,055
Vernon	36,464	34,454	33,321	25,939	28,449	30,609	32,992	33,277	27,071	21,090	21,628	38,048	Jun-21	38,048
Vilas Road	20,441	19,906	20,166	14,944	14,568	15,228	14,935	15,441	15,994	18,883	14,893	23,455	Jun-21	23,455
Village Green	13,122	13,069	12,499	13,076	13,041	14,092	13,901	13,833	13,053	12,294	10,044	14,979	Jun-21	14,979
Vine Street	27,967	23,103	22,171	14,241	15,470	16,930	16,437	20,532	16,935	16,477	21,039	27,204	Jul-20	27,967
Warrenton	16,751	17,642	16,931	16,787	18,235	18,655	19,792	19,722	18,420	17,721	15,639	16,341	Jan-21	19,792
Weston	9,336	10,982	9,944	9,540	8,887	6,245	6,370	6,356	5,928	6,024	4,983	10,058	Aug-20	10,982
Westside	13,076	12,755	12,474	11,827	13,076	13,697	14,399	13,857	13,241	11,760	11,460	15,237	Jun-21	15,237
White City	42,105	41,170	40,151	36,004	36,552	38,317	37,949	38,055	37,150	38,113	33,796	43,384	Jun-21	43,384
Winchester	23,810	25,277	23,089	19,401	20,231	19,529	20,666	19,138	20,129	17,567	16,937	26,217	Jun-21	26,217
Yew Ave	17,572	16,325	16,409	15,058	14,114	16,524	17,140	17,413	14,554	13,635	13,382	21,806	Jun-21	21,806
													Total	
Substation Peaks	119,268	125,776	60,398	19,907	66,261	148,176	191,772	87,988	61,586	15,352	-	1,747,014	2,643,497	
Weighting Factor	4.51%	4.76%	2.28%	0.75%	2.51%	5.61%	7.25%	3.33%	2.33%	0.58%	0.00%	66.09%	100.00%	

PacifiCorp
Oregon Marginal Cost Study
Distribution Substations Monthly Peaks - kW
12 months ended June 2022

A	B	C	D	E	F	G	H	I	J	K	L	M	N		
Substation		Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Peak Month	Peak Load
Agness Avenue		18,360	17,810	15,536	13,999	15,376	17,577	16,511	16,458	15,327	14,251	13,431	16,037	Jul-21	18,360
Albina		23,488	24,578	20,749	23,309	20,040	20,568	20,667	20,834	18,955	19,793	18,977	21,946	Aug-21	24,578
Alderwood		22,657	24,228	21,423	18,032	18,147	18,855	18,786	19,076	24,400	17,885	18,670	23,954	Mar-22	24,400
Applegate		10,467	10,419	8,497	10,153	11,317	11,032	12,847	13,213	11,444	10,887	9,114	9,502	Feb-22	13,213
Ashland		16,012	15,921	12,458	12,440	14,173	15,415	15,270	16,351	13,736	13,493	12,248	15,069	Feb-22	16,351
Bandon		1,791	2,003	1,987	2,370	2,257	2,520	2,482	3,164	3,023	3,236	2,795	2,416	Apr-22	3,236
Beall Lane		19,708	18,977	15,442	13,931	14,690	15,076	16,683	16,757	14,978	14,136	13,921	17,888	Jul-21	19,708
Belknap		28,978	29,637	24,326	19,915	21,479	22,387	23,188	23,781	21,177	19,778	21,529	26,814	Aug-21	29,637
Bend Plant		18,300	19,387	14,487	11,210	12,370	16,662	14,738	15,886	13,814	11,982	10,629	16,097	Aug-21	19,387
Bloss		10,171	11,626	11,974	10,170	10,025	9,668	9,634	11,212	9,752	10,912	8,954	9,580	Sep-21	11,974
Bly		1,910	1,699	1,422	1,146	1,002	1,040	1,211	1,177	1,083	1,067	1,447	2,088	Jun-22	2,088
REDACTED		928	895	875	930	968	957	921	926	893	893	922	917	Nov-21	968
Bond Street		18,359	18,900	14,099	13,523	14,500	18,381	16,762	18,881	16,531	14,001	13,055	16,649	Aug-21	18,900
Brookhurst		36,233	36,749	28,258	22,160	23,488	25,742	26,517	28,379	23,802	21,297	23,212	35,842	Aug-21	36,749
Bryant		25,767	25,441	21,884	16,959	18,862	22,680	22,318	22,485	19,260	18,992	17,443	21,935	Jul-21	25,767
Buchanan		24,031	27,782	22,903	20,813	24,046	24,260	26,715	25,479	22,647	22,246	19,861	21,390	Aug-21	27,782
Buckaroo		23,488	24,700	18,962	16,493	18,115	19,804	20,060	19,001	16,417	12,331	11,740	14,701	Aug-21	24,700
Calapooya		5,551	5,785	5,054	4,589	5,402	5,455	5,031	5,437	5,429	4,988	4,692	4,867	Aug-21	5,785
Campbell		20,546	20,428	16,221	14,069	15,347	15,844	16,130	16,141	13,068	12,089	12,244	16,291	Jul-21	20,546
Cannon Beach		4,897	4,373	4,499	5,470	6,458	7,949	9,023	8,068	6,292	6,578	5,787	4,414	Jan-22	9,023
Canyonville		7,238	7,691	7,434	6,965	7,659	8,020	8,048	8,290	7,737	7,867	6,702	7,419	Feb-22	8,290
Casebeer		8,799	6,785	5,930	2,646	2,771	3,062	5,880	3,347	2,967	4,114	6,905	6,849	Jul-21	8,799
Cave Junction		14,263	14,145	11,556	15,100	16,133	15,977	17,542	18,478	16,282	16,662	14,879	11,395	Feb-22	18,478
Caveman		20,547	20,116	17,007	12,151	13,749	18,232	15,650	15,535	13,603	12,726	13,226	17,383	Jul-21	20,547
Cherry Lane		7,333	7,294	7,174	7,321	7,410	7,317	7,480	7,510	7,285	9,686	9,661	7,093	Apr-22	9,686
Chiloquin		7,415	7,623	7,661	7,605	7,137	6,988	7,167	7,285	7,597	7,504	7,247	7,918	Jun-22	7,918
China Hat		19,124	20,869	15,318	18,955	20,164	22,467	23,518	25,672	22,931	18,489	17,870	17,699	Feb-22	25,672
Circle Blvd		15,760	17,017	15,190	14,716	14,301	13,979	13,677	14,084	14,511	14,611	15,527	15,965	Aug-21	17,017
Cleveland Ave.		33,272	34,937	28,196	25,986	28,432	32,367	30,609	33,674	32,082	32,913	25,593	31,229	Aug-21	34,937
Cloake		15,994	16,327	13,130	8,880	10,616	12,023	11,374	12,901	10,751	10,455	8,731	15,297	Aug-21	16,327
Coburg		2,477	2,654	2,096	1,584	1,831	2,155	2,159	2,257	1,946	1,830	1,617	2,245	Aug-21	2,654
Columbia		32,808	33,566	28,103	25,154	27,217	28,391	29,359	28,865	26,578	24,306	23,104	28,272	Aug-21	33,566
Coquille		10,402	13,380	11,039	13,319	15,152	16,527	16,285	17,608	15,324	15,521	13,554	11,046	Feb-22	17,608
Cully		12,152	13,652	10,055	8,756	9,707	11,241	11,207	10,632	9,551	7,711	7,002	9,814	Aug-21	13,652
Culver		9,544	7,052	6,430	6,573	7,050	8,402	8,547	10,040	8,439	6,824	5,623	5,905	Feb-22	10,040
Dairy		10,144	8,483	7,094	2,569	3,909	2,904	3,034	2,607	2,992	4,605	8,516	8,335	Jul-21	10,144
Dallas		35,885	39,087	29,229	27,599	30,710	35,004	35,635	38,644	33,378	32,094	26,849	32,328	Aug-21	39,087
Dalreed		53,434	49,732	36,996	17,533	8,146	8,107	10,165	7,926	22,084	25,749	33,617	47,030	Jul-21	53,434
Deschutes		8,473	8,562	6,901	9,314	10,257	11,432	13,537	14,701	12,638	9,681	8,708	7,266	Feb-22	14,701

Devils Lake	19,818	18,962	20,057	24,170	28,641	35,306	34,722	34,824	28,525	28,387	25,849	20,739	Dec-21	35,306
Dixon	3,577	3,837	3,024	2,165	2,395	2,605	2,723	2,686	2,299	2,366	2,489	3,007	Aug-21	3,837
Dodge Bridge	11,274	15,619	13,930	15,412	15,191	10,871	11,849	12,955	10,957	10,272	8,717	10,175	Aug-21	15,619
Dowell	16,102	16,070	13,398	10,843	11,993	12,605	13,359	13,900	12,110	11,375	10,489	15,047	Jul-21	16,102
Easy Valley	19,981	19,758	16,152	13,556	15,775	16,881	17,570	18,299	15,373	15,156	11,634	18,352	Jul-21	19,981
Empire	9,939	11,539	11,178	14,466	16,900	19,688	18,946	20,681	17,756	16,841	14,257	10,426	Feb-22	20,681
Fern Hill	1,154	1,622	2,129	2,597	2,976	3,168	2,779	2,670	2,646	2,097	1,762	1,462	Dec-21	3,168
Fielder Creek	11,693	11,522	9,557	10,514	10,771	11,256	12,274	13,147	11,785	11,169	9,013	9,566	Feb-22	13,147
Foothills Rd	13,944	13,690	11,008	9,526	10,014	10,360	10,641	11,057	10,093	9,507	9,957	13,398	Jul-21	13,944
Garden Valley	15,086	15,396	12,601	8,706	10,851	10,322	10,538	11,139	9,694	9,560	9,468	13,486	Aug-21	15,396
Glendale	10,247	9,902	8,863	11,307	11,567	12,275	13,390	13,965	12,774	12,201	11,161	9,404	Feb-22	13,965
Gold Hill	8,332	8,009	6,388	6,885	7,422	7,350	8,326	9,076	7,683	7,447	6,021	7,396	Feb-22	9,076
Gordon Hollow	4,345	4,641	3,304	3,253	3,704	4,999	5,076	5,376	4,168	3,653	3,070	3,739	Feb-22	5,376
Goshen	5,653	6,368	5,149	5,032	5,709	6,636	6,517	7,142	6,205	5,866	4,994	5,515	Feb-22	7,142
Grant Street	25,993	28,697	21,885	21,890	27,043	26,731	28,665	28,335	24,238	23,433	20,707	23,580	Aug-21	28,697
Green	14,471	14,686	12,564	10,044	12,576	13,624	13,496	15,740	12,997	12,581	10,581	13,699	Feb-22	15,740
Harrisburg	7,989	8,426	6,816	6,798	7,716	8,529	8,793	9,290	8,053	7,232	6,531	7,040	Feb-22	9,290
Hazelwood	6,869	7,343	5,490	6,052	6,272	6,866	7,332	7,226	6,461	5,960	5,406	5,821	Aug-21	7,343
Hillview	26,312	33,010	26,248	20,463	24,276	24,976	30,881	25,849	24,648	20,879	20,548	29,411	Aug-21	33,010
Holladay	19,870	21,863	20,823	17,386	17,109	19,584	18,376	18,755	16,105	16,590	15,734	20,056	Aug-21	21,863
Hollywood	30,476	34,728	26,509	19,930	22,168	26,706	26,053	25,532	22,255	23,022	19,626	30,942	Aug-21	34,728
Hood River	30,542	33,059	24,641	21,137	24,366	31,061	32,061	31,219	26,103	24,120	21,360	27,153	Aug-21	33,059
Hornet	15,832	15,608	12,948	10,205	11,389	12,930	12,689	13,423	11,505	11,176	10,404	13,615	Jul-21	15,832

Independence	22,197	23,683	18,846	15,057	16,750	18,513	18,928	19,358	16,862	16,168	13,572	16,468	Aug-21	23,683
Jacksonville	17,629	17,367	12,312	12,250	13,728	14,537	15,365	16,271	14,068	13,207	11,344	15,864	Jul-21	17,629
Jefferson	10,393	11,559	11,162	8,639	9,521	11,556	16,304	17,200	14,573	14,392	10,600	12,526	Feb-22	17,200
Jerome Prairie	14,427	14,604	11,014	13,049	14,491	14,311	9,309	9,565	8,472	8,061	7,026	7,455	Aug-21	14,604
Junction City	8,014	8,835	7,409	7,003	8,270	9,166	17,143	17,465	15,881	16,289	14,366	17,631	Jun-22	17,631
Killingsworth	18,649	20,251	16,214	15,309	16,709	18,770	18,863	19,400	17,628	20,597	14,658	19,740	Apr-22	20,597
Knappa Svensen	2,806	3,167	2,827	3,796	5,044	5,363	4,934	5,252	4,676	4,486	3,768	3,179	Dec-21	5,363
Knott	26,984	30,684	23,720	20,636	24,209	28,683	27,006	26,796	24,522	23,955	20,267	26,468	Aug-21	30,684
Lakeport	18,043	17,594	15,960	16,092	17,810	19,073	19,057	19,418	17,939	17,835	17,544	15,882	Feb-22	19,418
Lancaster	6,586	6,773	7,950	8,524	10,275	10,713	10,607	10,196	10,814	9,261	8,949	6,773	Mar-22	10,814
Lebanon	32,496	33,700	28,050	25,052	27,437	31,747	31,456	32,346	28,146	26,468	23,581	27,220	Aug-21	33,700
Lincoln	19,919	21,999	19,325	17,230	19,761	21,489	32,591	33,821	29,903	31,811	28,810	33,640	Feb-22	33,821
Lockhart	11,148	11,467	12,870	17,234	19,817	22,608	21,804	24,261	21,131	20,041	17,947	13,233	Feb-22	24,261
Lyons	17,342	18,189	17,645	18,602	20,462	20,284	20,886	20,990	21,022	19,645	17,632	17,422	Mar-22	21,022
Madras	18,790	19,133	15,032	16,816	17,408	20,689	20,994	24,394	19,728	16,907	13,067	17,264	Feb-22	24,394
Mallory	12,719	14,292	10,680	9,486	11,011	13,281	13,041	12,874	10,975	13,661	11,215	15,337	Jun-22	15,337
Marys River	14,419	15,116	13,401	14,660	14,993	15,719	16,825	17,711	15,908	15,683	14,340	12,593	Feb-22	17,711
Medford	25,056	24,762	20,349	15,402	17,071	18,076	2,153	10,225	8,446	7,497	7,404	12,386	Jul-21	25,056
Merlin	22,950	23,280	18,845	22,016	25,346	25,475	16,284	16,584	16,173	15,924	16,037	16,177	Dec-21	25,475
Merrill	9,336	7,772	7,269	4,831	4,603	5,585	26,279	26,554	25,793	21,617	24,550	31,570	Jun-22	31,570
Mile High	10,581	9,794	8,931	10,775	11,586	12,262	30,201	31,577	27,090	26,417	19,987	19,310	Feb-22	31,577
Murder Creek	50,524	54,318	50,109	46,199	45,780	49,460	8,749	5,878	5,008	8,652	10,721	9,097	Aug-21	54,318
Oak Knoll	18,868	18,537	14,008	15,594	17,109	19,408	12,143	13,039	12,155	11,993	11,648	9,753	Dec-21	19,408
O'Brien	1,413	1,331	1,099	1,483	1,584	1,641	49,504	47,673	46,617	46,805	65,816	63,946	May-22	65,816
REDACTED	21,334	24,422	21,543	18,706	16,323	16,967	23,426	21,527	17,080	17,115	15,454	17,441	Aug-21	24,422
Overpass	33,116	35,097	26,856	27,270	29,416	32,578	1,698	1,685	1,681	1,717	1,499	1,073	Aug-21	35,097
Pallette	456	379	328	329	397	467	17,704	17,952	17,599	16,139	16,301	17,420	Feb-22	17,952
Park Street	32,569	31,946	27,184	21,829	25,089	24,979	32,125	35,430	31,864	28,625	26,288	30,205	Feb-22	35,430
Parkrose	27,150	30,026	23,442	20,511	23,062	27,343	581	490	448	389	298	269	Aug-21	30,026
Pendleton	30,482	30,673	22,874	17,901	20,246	25,178	13,851	14,050	12,150	11,136	10,819	29,342	Aug-21	30,673
Pilot Butte	17,907	19,051	14,598	11,731	12,971	16,529	25,634	26,176	22,561	23,926	22,151	26,806	Jun-22	26,806
Pilot Rock	7,695	7,589	-	-	4,743	6,430	24,187	21,811	18,672	15,698	13,347	20,633	Jan-22	24,187
Prineville	36,706	37,307	30,339	30,645	33,450	36,343	14,787	16,745	14,178	12,215	11,048	16,954	Aug-21	37,307
Prospect Central	1,992	1,549	1,713	1,546	1,900	2,083	35,829	43,287	37,932	33,034	32,508	30,517	Feb-22	43,287
Queen Ave	37,075	40,484	32,421	23,775	28,039	33,445	31,291	31,246	28,088	26,607	23,527	34,464	Aug-21	40,484
Redmond 115	37,848	39,811	31,386	31,285	38,334	39,600	36,831	44,159	38,372	33,310	29,932	35,430	Feb-22	44,159
Riddle	16,485	16,162	13,979	14,523	16,446	17,070	19,115	21,412	16,988	16,471	14,125	15,337	Feb-22	21,412
REDACTED	11,880	12,162	12,489	12,505	12,657	12,737	12,183	11,985	11,389	11,783	11,556	11,026	Dec-21	12,737
Roseburg	22,343	23,596	19,756	15,868	19,284	19,605	21,357	23,365	19,823	19,560	16,235	21,780	Aug-21	23,596
Ross Ave	7,529	7,547	6,551	5,105	5,542	6,604	6,462	6,680	5,846	5,552	5,137	6,078	Aug-21	7,547
Roxy Ann	14,402	14,589	10,309	6,716	6,875	8,436	7,756	8,289	6,977	6,584	7,908	14,367	Aug-21	14,589
Russelville	29,372	32,422	25,378	22,402	25,379	30,881	30,404	29,695	25,184	25,733	21,837	28,064	Aug-21	32,422
Sage Road	30,866	30,196	25,865	20,722	23,491	25,041	24,194	24,970	24,426	21,542	22,755	28,151	Jul-21	30,866
Scenic	29,184	27,959	22,479	17,727	20,272	21,119	22,514	22,689	19,945	18,490	17,647	25,915	Jul-21	29,184
Scio	5,604	5,804	4,536	4,569	4,993	5,687	5,862	6,289	5,473	5,048	4,492	4,420	Feb-22	6,289
Seaside	16,787	13,785	18,121	15,896	18,707	23,736	21,713	20,920	18,739	18,423	16,242	14,382	Dec-21	23,736
Shevlin Park	22,189	22,985	16,096	13,807	14,721	20,205	17,983	18,813	17,564	23,366	13,670	20,564	Apr-22	23,366
Southgate	14,378	14,153	13,083	11,508	13,110	15,319	14,368	14,958	13,479	13,773	11,619	14,560	Dec-21	15,319

State Street	18,486	20,510	19,081	24,259	29,255	35,572	32,843	36,759	31,692	29,971	26,219	19,832	Feb-22	36,759
Stayton	35,054	38,167	30,054	26,643	31,206	35,029	36,836	39,282	33,021	36,354	26,728	31,714	Feb-22	39,282
Stevens Road	23,133	24,180	17,761	14,094	16,276	17,019	17,929	19,544	17,610	15,624	13,681	22,877	Aug-21	24,180
Sutherlin	12,176	12,426	10,418	9,530	10,936	11,508	11,781	13,496	11,207	10,667	9,096	11,158	Feb-22	13,496
Sweet Home	23,059	24,660	20,059	22,396	22,018	24,553	24,756	28,375	24,942	22,212	20,752	20,360	Feb-22	28,375
Takelma	9,211	9,239	6,813	8,641	9,865	9,666	10,658	11,871	9,771	9,310	7,093	8,696	Feb-22	11,871
Talent	18,577	18,623	14,091	14,997	17,452	18,119	19,294	20,861	17,329	15,973	13,790	17,791	Feb-22	20,861
Texum	12,522	12,495	9,896	10,761	12,129	12,898	12,688	13,172	14,898	11,749	10,623	9,620	Mar-22	14,898
Umatilla	15,286	14,457	12,568	12,990	9,862	12,061	13,104	11,883	9,821	8,930	9,403	13,604	Jul-21	15,286
Vernon	30,176	34,718	23,861	21,161	23,670	27,899	28,389	27,496	23,287	23,315	20,747	30,527	Aug-21	34,718
Vilas Road	20,867	20,391	18,118	13,380	14,603	15,624	16,129	16,429	14,761	14,054	16,091	20,746	Jul-21	20,867
Village Green	13,306	14,752	11,265	11,528	12,715	13,795	13,935	15,158	13,241	12,830	11,325	13,082	Feb-22	15,158
Vine Street	24,011	24,056	18,450	12,353	14,875	17,015	15,944	15,837	14,017	13,622	12,135	22,356	Aug-21	24,056
Warrenton	15,946	17,755	16,158	17,162	18,131	19,041	18,895	19,915	18,615	18,025	16,525	16,471	Feb-22	19,915
Weston	10,016	10,427	10,047	9,552	9,251	6,132	4,112	6,255	7,134	7,223	5,735	9,942	Aug-21	10,427
Westside	13,639	13,701	11,281	11,516	12,383	13,269	13,344	14,785	12,102	15,371	12,917	13,040	Apr-22	15,371
White City	42,946	41,313	38,196	35,992	35,932	38,487	37,844	39,982	36,050	35,087	34,157	38,632	Jul-21	42,946
Winchester	24,879	25,043	20,020	17,214	18,869	19,831	21,071	22,922	19,773	19,166	16,169	24,155	Aug-21	25,043
Yew Ave	18,447	20,556	15,152	13,923	15,257	18,813	17,293	19,442	17,347	14,217	12,878	16,939		
													Total	
Substation Peaks	424,997	1,089,883	11,974	-	968	140,512	33,210	741,399	71,134	72,256	65,816	101,349	2,753,497	
Weighting Factor	15.43%	39.58%	0.43%	0.00%	0.04%	5.10%	1.21%	26.93%	2.58%	2.62%	2.39%	3.68%	100.00%	

PacifiCorp
Oregon Marginal Cost Study
Distribution Substations Monthly Peaks - kW
12 months ended June 2023

A	B	C	D	E	F	G	H	I	J	K	L	M	N		
Substation		Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Peak Month	Peak Load
Agness Avenue		18,785	18,462	17,408	16,998	16,045	15,944	16,763	17,324	15,859	14,975	14,426	15,662	Jul-22	18,785
Albina		24,040	24,888	23,075	21,291	21,444	21,805	20,306	20,104	23,215	22,032	22,053	21,687	Aug-22	24,888
Alderwood		24,996	24,982	22,062	20,659	19,851	24,665	19,653	19,684	19,287	19,509	23,516	22,303	Jul-22	24,996
Applegate		11,277	10,563	9,724	9,233	11,506	12,097	13,503	13,051	11,444	11,015	7,928	9,113	Jan-23	13,503
Ashland		18,576	16,190	15,888	12,113	14,122	16,151	16,089	16,021	14,700	14,051	11,874	14,518	Jul-22	18,576
Bandon		2,018	1,792	1,975	2,133	2,359	2,761	2,674	2,848	2,933	3,187	2,004	2,107	Apr-23	3,187
Beall Lane		21,179	18,635	25,016	17,994	15,427	15,939	16,793	16,444	15,351	14,872	15,989	17,670	Sep-22	25,016
Belknap		31,678	29,123	28,805	21,738	21,411	23,094	23,130	23,082	25,150	23,960	27,570	26,791	Jul-22	31,678
Bend Plant		20,587	17,689	17,881	15,558	15,312	15,483	16,783	16,351	13,799	12,658	10,853	15,358	Jul-22	20,587
Bloss		11,376	9,650	11,707	10,175	2,653	1,242	840	597	628	543	444	335	Sep-22	11,707
Bly		2,011	2,216	1,862	2,523	1,193	1,518	1,371	1,263	1,638	1,566	1,188	2,035	Oct-22	2,523
REDACTED		890	1,032	1,062	913	1,013	961	907	940	915	935	969	897	Sep-22	1,062
Bond Street		20,857	17,833	17,137	13,196	16,789	20,062	20,373	17,517	15,098	13,679	11,551	15,567	Jul-22	20,857
Brookhurst		41,502	36,525	37,254	23,485	24,579	27,497	29,514	27,543	29,220	28,260	33,034	33,973	Jul-22	41,502
Bryant		27,601	24,708	25,566	16,935	20,753	23,694	22,835	21,087	21,167	19,400	18,371	22,085	Jul-22	27,601
Buchanan		28,363	26,954	21,947	19,334	27,454	27,170	26,262	26,091	23,953	21,804	16,828	20,345	Jul-22	28,363
Buckaroo		16,783	16,819	15,498	11,866	13,243	13,824	13,359	13,731	12,904	12,722	17,000	15,014	May-23	17,000
Calapooya		6,320	5,764	5,391	4,697	5,329	5,877	5,731	5,835	5,466	5,131	4,977	5,156	Jul-22	6,320
Campbell		19,320	19,012	17,985	13,259	12,827	16,829	16,974	16,313	15,438	14,768	17,202	20,447	Jun-23	20,447
Cannon Beach		4,736	4,147	4,395	4,847	6,517	7,890	7,437	8,454	9,701	6,677	4,727	4,207	Mar-23	9,701
Canyonville		7,828	7,280	7,180	6,168	8,129	8,094	8,555	8,259	6,313	5,951	5,557	6,066	Jan-23	8,555
Casebeer		8,157	7,039	7,316	3,338	3,038	3,771	3,690	3,258	3,355	3,152	7,053	6,890	Jul-22	8,157
Cave Junction		14,233	13,151	12,681	13,795	16,011	16,843	17,598	17,941	18,845	16,093	12,187	11,954	Mar-23	18,845
Caveman		22,149	20,291	18,779	13,931	14,607	15,919	16,398	16,310	14,431	13,129	15,154	17,622	Jul-22	22,149
Cherry Lane		7,364	8,300	7,335	7,167	7,630	7,368	7,438	7,724	7,511	7,497	7,227	7,328	Aug-22	8,300
Chiloquin		7,671	7,746	7,840	7,776	7,267	6,138	7,566	7,158	7,063	6,854	7,236	7,894	Jun-23	7,894
China Hat		22,331	19,414	18,557	16,405	22,372	26,276	29,231	25,346	22,555	20,131	15,631	16,687	Jan-23	29,231
Circle Blvd		17,178	17,348	15,451	15,105	14,290	14,279	14,306	13,891	14,929	14,529	15,406	15,661	Aug-22	17,348
Cleveland Ave.		36,641	33,636	32,822	25,750	32,884	36,251	47,582	34,434	30,204	28,882	24,975	29,716	Jan-23	47,582
Cloake		16,934	16,380	13,536	9,463	11,556	11,149	13,267	12,534	11,232	10,329	12,475	13,860	Jul-22	16,934
Coburg		2,721	2,380	2,158	1,604	2,135	2,360	2,320	2,234	2,037	1,840	2,285	2,283	Jul-22	2,721
Columbia		33,275	32,405	29,549	24,564	27,789	31,906	29,890	28,636	28,910	26,764	29,128	29,471	Jul-22	33,275
Coquille		10,110	11,561	10,885	12,511	16,280	16,403	18,115	17,743	16,404	15,953	12,650	11,258	Jan-23	18,115
Crowfoot		16,172	15,051	849	8,725	15,112	16,061	4	12	14,428	13,206	13,709	14,086	Jul-22	16,172
Cully		10,789	10,550	8,562	7,593	8,415	10,706	9,465	9,726	8,381	9,565	8,869	10,078	Jul-22	10,789
Culver		7,124	6,806	6,286	5,584	7,827	9,043	10,218	9,020	7,805	6,991	5,000	6,297	Jan-23	10,218
Dairy		9,654	8,504	8,167	3,441	2,475	3,000	2,678	2,403	2,643	3,134	8,017	7,074	Jul-22	9,654
Dallas		38,003	35,121	30,209	25,844	32,029	39,422	37,129	37,679	35,364	30,789	29,918	29,492	Dec-22	39,422
Dalreed		51,656	48,796	42,829	21,993	7,905	8,069	7,685	7,882	17,789	25,026	36,279	49,283	Jul-22	51,656
Deschutes		8,571	7,880	7,976	7,923	12,591	13,902	16,472	14,095	10,875	10,330	6,634	7,307	Jan-23	16,472

Devils Lake	19,596	18,941	19,345	23,842	30,496	36,731	34,978	35,247	32,075	30,060	21,348	19,325	Dec-22	36,731
Dixon	3,642	3,506	3,156	2,519	2,500	2,823	2,625	2,777	2,543	2,726	3,034	3,238	Jul-22	3,642
Dodge Bridge	12,416	11,080	11,199	9,058	11,142	12,939	13,686	12,755	11,532	10,533	7,930	16,080	Jun-23	16,080
Dowell	17,743	16,457	14,884	10,337	12,487	12,894	14,219	14,030	12,028	11,285	12,747	14,740	Jul-22	17,743
Easy Valley	21,810	19,990	17,872	11,505	16,185	16,836	19,079	18,712	16,042	14,920	14,329	17,439	Jul-22	21,810
Empire	9,145	8,669	9,902	13,485	17,722	19,340	21,664	20,529	20,618	18,165	12,780	10,648	Jan-23	21,664
Fern Hill	1,221	1,160	2,644	1,845	2,609	3,477	4,085	4,255	3,724	3,257	2,451	1,929	Feb-23	4,255
Fielder Creek	12,037	11,317	10,625	9,499	11,415	12,279	13,037	12,404	11,066	11,034	7,878	9,315	Jan-23	13,037
Foothills Rd	15,511	14,090	14,061	10,146	10,275	11,062	11,275	10,906	10,498	10,375	11,590	13,472	Jul-22	15,511
Garden Valley	15,399	14,822	12,666	9,765	10,262	10,335	11,351	10,862	10,147	10,937	11,750	12,676	Jul-22	15,399
Glendale	10,567	10,241	9,296	10,256	12,563	12,927	13,887	13,276	12,703	38,302	34,196	16,884	Apr-23	38,302
Gold Hill	8,809	8,100	7,928	5,885	7,937	8,647	9,192	8,786	7,978	7,647	5,912	7,130	Jan-23	9,192
Gordon Hollow	4,960	4,509	4,025	3,063	4,991	6,264	5,586	5,404	4,344	3,699	3,264	3,613	Dec-22	6,264
Goshen	6,205	6,056	5,291	4,707	6,815	6,661	7,444	7,027	6,233	5,742	5,360	5,497	Jan-23	7,444
Grant Street	27,857	25,798	22,295	21,147	30,354	29,174	29,102	29,578	26,646	25,787	26,742	26,317	Nov-22	30,354
Green	15,267	14,903	13,194	10,088	12,880	13,795	16,430	15,272	13,754	12,471	12,028	12,282	Jan-23	16,430
Harrisburg	8,341	7,802	6,944	6,644	8,549	8,449	8,871	9,266	8,371	7,629	6,744	6,796	Feb-23	9,266
Hazelwood	7,088	6,449	5,646	5,601	6,591	7,439	6,886	7,298	6,288	6,114	6,113	6,281	Dec-22	7,439
Hillview	30,695	27,283	25,916	19,542	29,205	30,433	25,856	25,390	25,697	27,619	24,861	24,589	Jul-22	30,695
Holladay	22,204	22,702	18,844	18,287	19,358	20,104	18,412	17,641	22,908	16,634	18,769	18,236	Mar-23	22,908
Hollywood	34,318	33,094	27,468	22,625	24,065	31,979	25,969	26,838	24,708	23,064	27,994	26,534	Jul-22	34,318
Hood River	32,591	31,720	27,652	18,819	27,677	36,282	33,046	31,055	26,377	23,791	24,328	25,351	Dec-22	36,282
Hornet	16,610	15,353	14,978	10,672	12,187	14,458	14,290	13,204	13,108	11,948	11,561	13,284	Jul-22	16,610
Independence	21,493	20,168	17,477	13,158	16,925	20,364	19,093	20,077	17,485	15,672	16,171	17,618	Jul-22	21,493

Jacksonville	19,725	16,724	16,433	9,959	13,667	15,871	16,660	15,291	15,149	13,533	12,165	15,347	Jul-22	19,725
Jefferson	15,508	13,702	12,205	10,387	16,122	16,245	17,836	18,794	19,182	14,407	10,584	12,390	Mar-23	19,182
Jerome Prairie	8,635	8,208	7,493	6,751	8,656	9,241	9,625	9,629	8,644	7,625	7,117	7,312	Feb-23	9,629
Junction City	18,869	18,396	15,553	13,657	15,822	18,517	17,176	16,814	15,898	14,508	12,011	8,895	Jul-22	18,869
Killingsworth	21,233	21,183	18,472	19,941	24,599	31,125	26,406	22,371	20,966	19,227	20,723	22,399	Dec-22	31,125
Knappa Svensen	3,032	3,262	2,823	3,519	4,723	6,073	5,500	5,423	5,228	4,467	3,297	2,879	Dec-22	6,073
Knott	30,237	29,181	26,022	21,193	25,881	33,498	28,024	28,334	24,974	23,416	26,373	24,914	Dec-22	33,498
Lakeport	17,718	17,217	16,916	16,405	18,266	18,905	18,942	18,808	18,769	18,246	17,261	16,042	Jan-23	18,942
Lancaster	7,867	8,071	7,742	7,613	9,102	9,703	11,629	12,543	11,620	9,385	7,806	7,915	Feb-23	12,543
Lebanon	33,372	31,750	29,487	24,072	30,502	32,276	33,026	31,804	28,244	27,408	27,193	28,569	Jul-22	33,372
Lincoln	36,562	34,488	32,745	29,677	32,070	37,609	35,015	35,193	32,443	30,947	33,276	31,490	Dec-22	37,609
Lockhart	11,710	12,541	12,215	17,226	20,592	22,990	23,690	23,241	22,636	20,974	14,874	12,323	Jan-23	23,690
Lyons	18,373	17,369	15,720	16,344	20,080	20,992	21,704	20,911	21,578	20,003	16,855	16,906	Jan-23	21,704
Madras	19,892	21,721	17,335	14,343	19,277	24,248	24,647	22,649	18,946	17,693	15,079	17,256	Jan-23	24,647
Mallory	16,550	13,392	11,509	9,531	11,317	15,502	12,570	13,589	18,001	10,148	12,040	11,099	Mar-23	18,001
Marys River	16,446	16,661	15,018	14,589	16,844	17,319	17,193	17,155	16,012	15,302	13,920	14,207	Dec-22	17,319
Medford	14,530	13,502	12,415	8,077	8,793	11,520	10,291	9,442	8,110	7,703	11,240	11,586	Jul-22	14,530
Merlin	15,258	15,731	16,407	15,759	15,668	16,017	16,374	16,655	16,468	16,700	16,880	16,340	May-23	16,880
Merrill	42,742	35,754	35,470	26,309	24,706	27,552	28,480	36,310	25,400	15,761	34,776	34,495	Jul-22	42,742
Mile High	25,077	22,360	19,123	18,192	27,259	29,617	31,397	32,594	25,963	24,615	17,065	18,896	Feb-23	32,594
Murder Creek	16,228	13,931	7,488	4,265	5,191	5,931	5,896	5,457	12,100	4,960	7,927	7,669	Jul-22	16,228
Oak Knoll	10,482	10,398	10,056	16,472	22,210	13,554	13,920	12,980	12,407	11,904	11,060	9,719	Nov-22	22,210
O'Brien	54,674	49,646	48,572	40,225	45,618	53,030	50,009	52,768	49,438	47,776	54,121	51,583	Jul-22	54,674
REDACTED	22,277	18,861	18,285	14,549	17,295	19,828	19,766	19,939	18,307	17,904	13,245	16,758	Jul-22	22,277
Overpass	1,368	1,274	1,183	1,326	1,450	1,509	1,616	1,550	1,939	1,432	1,192	1,083	Mar-23	1,939
Pallette	22,738	24,994	23,116	18,303	18,028	19,408	20,024	21,739	20,611	20,768	21,974	23,555	Aug-22	24,994
Park Street	34,430	32,681	30,947	27,012	32,308	37,148	37,616	35,810	31,797	30,885	25,438	27,908	Jan-23	37,616
Parkrose	445	395	359	314	467	523	566	441	401	375	249	266	Jan-23	566
Pendleton	36,454	34,126	30,999	24,178	26,003	27,990	28,856	29,566	25,520	23,233	26,702	30,543	Jul-22	36,454
Pilot Butte	29,372	28,588	24,303	19,322	23,863	31,012	25,501	26,646	23,312	23,776	26,637	24,830	Dec-22	31,012
Pilot Rock	25,680	23,200	20,487	12,804	17,716	22,469	19,814	18,978	16,144	15,545	17,759	18,931	Jul-22	25,680
Prineville	20,304	17,656	17,884	11,188	15,559	18,602	18,418	17,362	14,030	12,980	12,756	16,309	Jul-22	20,304
Prospect Central	40,072	36,793	33,644	29,534	36,887	42,643	46,154	40,587	37,951	36,131	26,752	32,894	Jan-23	46,154
Queen Ave	40,648	39,467	34,302	26,809	30,302	36,555	30,569	37,061	29,138	27,295	33,061	34,905	Jul-22	40,648
Redmond 115	40,947	38,889	36,451	30,461	37,438	45,869	47,432	42,045	36,988	34,694	29,230	33,678	Jan-23	47,432
Riddle	16,887	16,585	14,357	14,195	18,534	19,404	20,780	19,746	17,795	16,940	13,467	13,221	Jan-23	20,780
REDACTED	10,020	10,445	10,708	11,414	12,182	10,984	11,023	11,268	11,812	11,437	10,942	10,985	Nov-22	12,182
Roseburg	23,381	23,259	19,737	15,900	23,519	21,820	23,635	22,172	23,145	19,855	18,550	19,516	Jan-23	23,635
Ross Ave	7,667	6,860	7,366	4,780	6,018	6,622	6,539	6,214	5,935	5,497	4,738	5,503	Jul-22	7,667
Roxy Ann	17,350	14,684	14,792	8,654	7,159	8,036	8,383	8,016	7,427	9,037	10,854	13,617	Jul-22	17,350
Russelville	31,401	30,606	26,167	17,926	21,969	30,494	29,518	32,272	27,618	24,467	25,835	24,800	Feb-23	32,272
Sage Road	32,880	30,877	29,664	24,221	23,328	25,485	25,077	25,369	25,593	30,973	24,950	28,514	Jul-22	32,880
Scenic	31,922	28,345	29,249	19,187	20,509	22,699	23,241	22,730	20,990	19,743	23,324	27,221	Jul-22	31,922
Scio	5,381	5,179	4,597	4,251	5,855	6,175	6,349	6,207	5,322	4,808	4,114	4,720	Jan-23	6,349
Seaside	14,450	13,804	13,599	15,392	19,789	23,199	26,205	22,546	20,333	19,620	14,798	13,328	Jan-23	26,205
Shevlin Park	26,337	21,068	21,501	13,972	18,156	21,639	20,319	22,307	18,623	16,809	19,538	20,940	Jul-22	26,337
Southgate	17,007	15,397	12,417	11,318	14,747	14,493	16,784	16,323	14,313	14,073	13,269	13,184	Jul-22	17,007
State Street	17,724	18,092	18,404	23,216	30,983	33,736	38,294	36,058	35,908	33,375	23,596	19,142	Jan-23	38,294

Stayton	37,459	34,909	30,806	24,694	35,037	36,960	38,340	38,123	32,015	29,573	29,021	30,981	Jan-23	38,340
Stevens Road	25,904	24,719	23,399	14,597	18,720	21,108	21,197	20,729	19,209	16,779	17,128	20,409	Jul-22	25,904
Sutherlin	12,531	12,016	10,545	8,774	12,028	11,457	14,037	12,843	11,931	10,843	10,194	10,583	Jan-23	14,037
Sweet Home	25,517	23,946	21,514	20,520	26,795	27,192	30,122	28,850	25,792	21,503	16,655	21,264	Jan-23	30,122
Takelma	10,077	8,876	9,123	7,682	10,546	11,919	12,406	11,351	10,061	9,827	6,400	8,039	Jan-23	12,406
Talent	22,034	19,413	19,355	13,919	18,259	20,560	21,593	20,726	19,917	17,915	14,416	18,208	Jul-22	22,034
Texum	12,553	12,250	11,611	11,055	12,399	14,322	14,093	13,092	13,095	11,970	9,849	9,599	Dec-22	14,322
Umatilla	15,094	14,294	13,519	10,764	10,069	13,650	12,328	12,469	9,882	9,439	11,228	13,332	Jul-22	15,094
Vernon	34,749	33,229	26,014	22,071	26,307	35,015	29,697	30,782	33,544	22,202	27,694	28,167	Dec-22	35,015
Vilas Road	22,891	21,197	20,666	15,733	15,227	16,609	16,623	16,320	15,528	15,144	17,128	19,478	Jul-22	22,891
Village Green	14,244	13,463	11,731	10,849	13,961	14,877	15,470	14,797	13,143	9,657	10,845	11,175	Jan-23	15,470
Vine Street	25,841	23,693	19,528	15,497	16,074	19,056	16,315	16,716	15,208	18,406	19,817	18,521	Jul-22	25,841
Warrenton	16,358	17,397	16,428	16,365	19,101	19,936	20,331	20,461	19,683	19,301	17,038	16,453	Feb-23	20,461
Weston	10,649	11,102	10,321	9,044	6,218	4,209	6,604	6,202	6,064	5,643	5,032	8,757	Aug-22	11,102
Westside	19,081	13,817	14,007	12,464	13,805	14,684	14,785	14,092	14,109	13,746	10,554	10,798	Jul-22	19,081
White City	43,236	43,331	40,176	35,398	40,019	47,348	36,286	38,090	36,821	34,881	36,907	37,061	Dec-22	47,348
Winchester	26,087	25,183	21,263	15,345	20,208	20,658	23,776	22,361	20,652	18,885	19,793	21,199	Jul-22	26,087
Yew Ave	20,688	19,061	17,621	13,067	17,082	21,178	21,620	19,589	15,886	15,372	13,847	16,861	Jan-23	21,620
													Total	
Substation Peaks	1,223,592	86,632	37,785	2,523	64,746	379,458	679,454	121,021	90,575	41,489	33,880	44,420	2,805,575	
Weighting Factor	43.61%	3.09%	1.35%	0.09%	2.31%	13.53%	24.22%	4.31%	3.23%	1.48%	1.21%	1.58%	100.00%	
Three-Year Average														
Weighting Factor	21.19%	15.81%	1.36%	0.28%	1.62%	8.08%	10.89%	11.52%	2.71%	1.56%	1.20%	23.78%	100.00%	

Uncollectables

PacifiCorp
Oregon Marginal Cost Study
Allocation of Uncollectible Expense between Members of Class
12 Months Ended December 2025

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
		Del.	Percent of Total Revenues				Allocated Net Uncollectible				
Line	Description	Volt	Residential	Commercial	Industrial	Irrigation	Residential	Commercial	Industrial	Irrigation	Total
1	Res - Sch 4	(sec)	100.00%	0.00%	0.00%	0.00%	3,547,018	-	-	-	3,547,018
2											
3	GS - Sch 23	(sec)	0.00%	21.78%	1.86%	0.00%	-	81,256	257	-	81,513
4	GS - Sch 23	(pri)	0.00%	0.03%	0.03%	0.00%	-	101	4	-	105
5	GS - Sch 23	Total	0.00%	21.81%	1.89%	0.00%	-	81,356	261	-	81,618
6											
7	GS - Sch 28	(sec)	0.00%	27.99%	5.81%	0.00%	-	104,424	802	-	105,226
8	GS - Sch 28	(pri)	0.00%	0.19%	0.39%	0.00%	-	713	54	-	767
9	GS - Sch 28	Total	0.00%	28.18%	6.20%	0.00%	-	105,137	856	-	105,993
10											
11	GS - Sch 30	(sec)	0.00%	13.34%	12.52%	0.00%	-	49,769	1,728	-	51,497
12	GS - Sch 30	(pri)	0.00%	0.77%	1.08%	0.00%	-	2,878	148	-	3,026
13	GS - Sch 30	Total	0.00%	14.11%	13.59%	0.00%	-	52,647	1,876	-	54,523
14											
15	LPS - Sch 48	(sec)	0.00%	4.03%	18.19%	0.00%	-	15,053	2,512	-	17,565
16	LPS - Sch 48	(pri)	0.00%	13.25%	58.61%	0.00%	-	49,446	8,092	-	57,539
17	LPS - Sch 48	(trn)	0.00%	18.62%	1.51%	0.00%	-	69,456	208	-	69,664
18	LPS - Sch 48	Total	0.00%	35.90%	78.32%	0.00%	-	133,955	10,813	-	144,768
19											
20	Irg - Sch 41	(sec)	0.00%	0.00%	0.00%	100.00%	-	-	-	41,210	41,210
21											
22	Total						3,547,018	373,095	13,806	41,210	3,975,129

12 Months Ended June 2023 Net Write-offs	
Residential	$3,547,018
Commercial	$373,095
Industrial	$13,806
Irrigation	$41,210
Total	3,975,129

Revenues

PacifiCorp
Oregon Marginal Cost Study
Revenues
12 Months Ended December 2025

Line	Description	(A) Del. Volt	(B) Residential	(C) Commercial	(D) Industrial	(E) Irrigation	(F) PS&H	(G) Total
1	Res - Sch 4	(sec)	786,075,316	-	-	-	-	786,075,316
2								
3	GS - Sch 23	(sec)	-	157,321,246	2,335,114	-	-	159,656,360
4	GS - Sch 23	(pri)	-	194,939	35,504	-	-	230,443
5	GS - Sch 23	Total	-	157,516,185	2,370,618	-	-	159,886,803
6								
7	GS - Sch 28	(sec)	-	202,177,015	7,283,467	-	-	209,460,482
8	GS - Sch 28	(pri)	-	1,380,206	493,630	-	-	1,873,836
9	GS - Sch 28	Total	-	203,557,221	7,777,097	-	-	211,334,318
10								
11	GS - Sch 30	(sec)	-	96,359,540	15,693,758	-	-	112,053,298
12	GS - Sch 30	(pri)	-	5,571,208	1,348,365	-	-	6,919,573
13	GS - Sch 30	Total	-	101,930,748	17,042,123	-	-	118,972,871
14								
15	LPS - Sch 48	(sec)	-	29,145,254	22,814,294	-	-	51,959,548
16	LPS - Sch 48	(pri)	-	95,734,013	73,496,480	-	-	169,230,493
17	LPS - Sch 48	(trn)	-	134,474,636	1,891,067	-	-	136,365,703
18	LPS - Sch 48	Total	-	259,353,903	98,201,841	-	-	357,555,744
19								
20	Irg - Sch 41	(sec)	-	-	-	32,686,893	-	32,686,893
21								
22	Lgt - Sch 15	(sec)	-	-	-	-	839,381	839,381
23	Lgt - Sch 51	(sec)	-	-	-	-	2,902,697	2,902,697
24	Lgt - Sch 53	(sec)	-	-	-	-	486,692	486,692
25	Lgt - Sch 54	(sec)	-	-	-	-	90,540	90,540
26	Lgt - Total	(sec)	-	-	-	-	4,319,310	4,319,310
27								
28	Total		786,075,316	722,358,057	125,391,679	32,686,893	4,319,310	1,670,831,255

Docket No. UE 433
Exhibit PAC/1909
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Target Functionalized Revenues and Billing Determinants

February 2024

PACIFIC POWER
STATE OF OREGON
Functionalized Revenue Targets and Summary of Proposed Functionalized Revenues
Forecast 12 Months Ended December 31, 2025

Rate Schedule (1)	(2)	Present Revenues ($000) (3)	Cost of Service Revenues ($000) (4)	Target with Unadjusted NPC Revenues ($000) (5)	Summary of Proposed Functionalized Revenues ($000) (6)
Schedule 4, Residential					
	Transmission & Ancillary Services[1]	$53,188	$48,830	$48,830	$48,848
	System Usage- Schedule 200 Related	$4,456	$4,048	$4,048	$4,051
	System Usage- T&A and Schedule 201 Related	$6,656	$7,662	$7,662	$7,640
	Distribution	$313,400	$404,421	$404,421	$404,433
	Other Adjustments	$1,100	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$162,632	$151,248	$151,248	$151,231
	Generation Energy - Net Power Costs (Sch 201)	$244,643	$237,471	$244,643	$244,643
	Total	$786,075	$853,679	$860,851	$860,844
Schedule 23, Small General Service					
	Transmission & Ancillary Services[1]	$9,064	$12,108	$12,108	$12,109
	System Usage- Schedule 200 Related	$848	$744	$744	$744
	System Usage- T&A and Schedule 201 Related	$1,232	$1,482	$1,482	$1,487
	Distribution	$71,495	$91,009	$91,009	$91,003
	Other Adjustments	$209	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$30,768	$28,642	$28,642	$28,639
	Generation Energy - Net Power Costs (Sch 201)	$46,270	$44,971	$46,270	$46,270
	Total	$159,887	$178,956	$180,255	$180,252
Schedule 28, General Service 31-200kW					
Secondary Voltage					
	Transmission & Ancillary Services[1]	$18,256	$14,874	$14,874	$14,913
	System Usage- Schedule 200 Related	$1,471	$1,379	$1,379	$1,369
	System Usage- T&A and Schedule 201 Related	$2,125	$2,576	$2,576	$2,575
	Distribution	$53,469	$73,326	$73,326	$73,292
	Other Adjustments	$368	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$53,431	$49,960	$49,960	$49,958
	Generation Energy - Net Power Costs (Sch 201)	$80,341	$78,441	$80,341	$80,341
	Total	$209,460	$220,556	$222,456	$222,448
Primary Voltage					
	Transmission & Ancillary Services[1]	$116	$148	$148	$148
	System Usage- Schedule 200 Related	$15	$13	$13	$13
	System Usage- T&A and Schedule 201 Related	$22	$24	$24	$24
	Distribution	$345	$672	$672	$672
	Other Adjustments	$4	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$548	$509	$509	$509
	Generation Energy - Net Power Costs (Sch 201)	$824	$798	$824	$824
	Total	$1,874	$2,164	$2,190	$2,190
Schedule 30, General Service 201-999kW					
Secondary Voltage					
	Transmission & Ancillary Services[1]	$9,028	$8,773	$8,773	$8,778
	System Usage- Schedule 200 Related	$877	$812	$812	$814
	System Usage- T&A and Schedule 201 Related	$1,265	$1,512	$1,512	$1,515
	Distribution	$19,935	$32,266	$32,266	$31,960
	Other Adjustments	$225	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$32,428	$30,124	$30,124	$30,433
	Generation Energy - Net Power Costs (Sch 201)	$48,295	$47,297	$48,295	$48,295
	Total	$112,053	$120,784	$121,782	$121,795
Primary Voltage					
	Transmission & Ancillary Services[1]	$579	$521	$521	$520
	System Usage- Schedule 200 Related	$54	$51	$51	$51
	System Usage- T&A and Schedule 201 Related	$79	$94	$94	$94
	Distribution	$1,187	$1,857	$1,857	$1,847
	Other Adjustments	$14	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$2,016	$1,820	$1,820	$1,833
	Generation Energy - Net Power Costs (Sch 201)	$2,990	$2,857	$2,990	$2,990
	Total	$6,920	$7,201	$7,334	$7,334
Schedule 41, Agricultural Pumping Service					
	Transmission & Ancillary Services[1]	$1,590	$1,550	$1,550	$1,550
	System Usage- Schedule 200 Related	$162	$136	$136	$136
	System Usage- T&A and Schedule 201 Related	$233	$252	$252	$251
	Distribution	$15,804	$22,410	$22,410	$22,410
	Other Adjustments	$40	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$5,934	$5,511	$5,511	$5,511
	Generation Energy - Net Power Costs (Sch 201)	$8,924	$8,653	$8,924	$8,924
	Total	$32,687	$38,512	$38,783	$38,783

PACIFIC POWER
STATE OF OREGON
Functionalized Revenue Targets and Summary of Proposed Functionalized Revenues
Forecast 12 Months Ended December 31, 2025

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]	$4,048	$3,805	$3,805	$3,800
	System Usage- Schedule 200 Related	$400	$375	$375	$377
	System Usage- T&A and Schedule 201 Related	$571	$695	$695	$697
	Distribution	$10,414	$14,726	$14,726	$14,684
	Other Adjustments	$97	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$14,583	$13,425	$13,425	$13,467
	Generation Energy - Net Power Costs (Sch 201)	$21,846	$21,078	$21,846	$21,846
	Total	$51,960	$54,104	$54,871	$54,871
Primary Voltage					
	Transmission & Ancillary Services[1]	$12,390	$13,557	$13,557	$13,550
	System Usage- Schedule 200 Related	$1,455	$1,327	$1,327	$1,325
	System Usage- T&A and Schedule 201 Related	$2,084	$2,446	$2,446	$2,454
	Distribution	$19,170	$38,991	$38,991	$39,002
	Other Adjustments	$369	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$53,651	$49,534	$49,534	$49,530
	Generation Energy - Net Power Costs (Sch 201)	$80,111	$77,772	$80,111	$80,111
	Total	$169,230	$183,627	$185,966	$185,971
Transmission Voltage					
	Transmission & Ancillary Services[1]	$10,739	$10,808	$10,808	$10,797
	System Usage- Schedule 200 Related	$1,258	$1,150	$1,150	$1,142
	System Usage- T&A and Schedule 201 Related	$1,761	$2,106	$2,106	$2,109
	Distribution	$8,883	$22,205	$22,205	$22,211
	Other Adjustments	$329	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$45,130	$41,441	$41,441	$41,448
	Generation Energy - Net Power Costs (Sch 201)	$68,267	$65,065	$68,267	$68,267
	Total	$136,366	$142,775	$145,977	$145,975
Schedules 15, 51, 53, 54 Lighting					
Secondary Voltage					
	Transmission & Ancillary Services[1]	$26	$20	$20	$20
	System Usage- Schedule 200 Related	$10	$9	$9	$9
	System Usage- T&A and Schedule 201 Related	$14	$14	$14	$14
	Distribution	$3,256	$3,732	$3,732	$3,732
	Other Adjustments	$5	$0	$0	$0
	Generation Energy - Other (non-NPC) (Sch 200)	$408	$310	$310	$310
	Generation Energy - Net Power Costs (Sch 201)	$600	$486	$600	$600
	Total	$4,319	$4,570	$4,684	$4,685
TOTAL		**$1,670,831**	**$1,806,926**	**$1,825,149**	**$1,825,149**
	Employee Discount	-$445		-$486	-$486
Additional Rate Schedules					
	Schedule 47	$5,048		$6,123	$6,123
	Schedule 848	$1,517		$3,829	$3,829
Total Oregon		**$1,676,952**		**$1,834,616**	**$1,834,615**
	Base Revenue Increase (excluding base Insurance Cost Adjustment)			**$157,664**	**$157,664**

[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, 2023
Forecast 12 Months Ended December 31, 2025

Schedule	Actual 7/22-6/23 Units	Normalized 7/22-6/23 Units	Forecast 1/25 - 12/25 Units		Present Price		Present Dollars	Proposed Price		Proposed Dollars
Schedule No. 4										
Residential Service										
Transmission & Ancillary Services Charge										
per kWh	6,110,468,412	5,814,272,066	5,787,620,059	kWh	0.919	¢	$53,188,228	0.844	¢	$48,847,513
System Usage Charge										
Sch 200 related, per kWh	6,110,468,412	5,814,272,066	5,787,620,059	kWh	0.077	¢	$4,456,467	0.070	¢	$4,051,334
T&A and Sch 201 related, per kWh	6,110,468,412	5,814,272,066	5,787,620,059	kWh	0.115	¢	$6,655,763	0.132	¢	$7,639,658
Distribution Charge										
Basic Charge Single Family, per month	5,114,835	5,114,835	4,928,360	bill	$11.00		$54,211,960	$16.00		$78,853,760
Basic Charge Multi Family, per month	1,281,323	1,281,323	1,234,609	bill	$8.00		$9,876,872	$9.00		$11,111,481
Total Bills	6,396,158	6,396,158	6,162,969	bill						
Add'l Basic Charge 3 phase, per month	2,881	2,881	2,881	bill	$0.00		$0	$9.00		$25,929
Three Phase Demand Charge, per kW demand	15,207	15,207	15,137	kW	$2.20		$33,301	$0.00		$0
Three Phase Minimum Demand Charge, per month	1,490	1,490	1,436	bill	$3.80		$5,457	$0.00		$0
Distribution Energy Charge, per kWh	6,110,468,412	5,814,272,066	5,787,620,059	kWh	4.307	¢	$249,272,796	5.433	¢	$314,441,398
Energy Charge - Schedule 200										
per kWh	6,110,468,412	5,814,272,066	5,787,620,059	kWh	2.810	¢	$162,632,124	2.613	¢	$151,230,512
Subtotal	6,110,468,412	5,814,272,066	5,787,620,059	kWh			$540,332,968			$616,201,585
Renewable Adjustment Clause (202), per kWh	6,110,468,412	5,814,272,066	5,787,620,059	kWh	0.019	¢	$1,099,648	0.000	¢	$0
Insurance Premium Adder- Base (80), per kWh	6,110,468,412	5,814,272,066	5,787,620,059	kWh	0.000	¢	$0	0.404	¢	$23,381,985
Subtotal							$541,432,616			$639,583,570
Schedule 201										
per kWh	6,110,468,412	5,814,272,066	5,787,620,059	kWh	4.227	¢	$244,642,700	4.227	¢	$244,642,700
Total	6,110,468,412	5,814,272,066	5,787,620,059	kWh			$786,075,316			$884,226,270
								Change		$98,150,954
Schedule No. 4 (Employee Discount)										
Residential Service										
Transmission & Ancillary Services Charge										
per kWh	13,425,928	13,425,928	13,364,385	kWh	0.919	¢	$122,819	0.844	¢	$112,795
System Usage Charge										
Sch 200 related, per kWh	13,425,928	13,425,928	13,364,385	kWh	0.077	¢	$10,291	0.070	¢	$9,355
T&A and Sch 201 related, per kWh	13,425,928	13,425,928	13,364,385	kWh	0.115	¢	$15,369	0.132	¢	$17,641
Distribution Charge										
Basic Charge Single Family, per month	10,403	10,403	10,024	bill	$11.00		$110,264	$16.00		$160,384
Basic Charge Multi Family, per month	388	388	374	bill	$8.00		$2,992	$9.00		$3,366
Total Bills	10,791	10,791	10,398	bill						
Three Phase Demand Charge, per kW demand	0	0	0	kW	$2.20		$0	$0.00		$0
Three Phase Minimum Demand Charge, per month	0	0	0	bill	$3.80		$0	$0.00		$0
Distribution Energy Charge, per kWh	13,425,928	13,425,928	13,364,385	kWh	4.307	¢	$575,604	5.433	¢	$726,087
Energy Charge - Schedule 200										
per kWh	13,425,928	13,425,928	13,364,385	kWh	2.810	¢	$375,539	2.613	¢	$349,211
Subtotal	13,425,928	13,425,928	13,364,385	kWh			$1,212,878			$1,378,839
Renewable Adjustment Clause (202), per kWh	13,425,928	13,425,928	13,364,385	kWh	0.019	¢	$2,539	0.000	¢	$0
Insurance Premium Adder- Base (80), per kWh	13,425,928	13,425,928	13,364,385	kWh	0.000	¢	$0	0.404	¢	$53,992
Subtotal							$1,215,417			$1,432,831
Schedule 201										
per kWh	13,425,928	13,425,928	13,364,385	kWh	4.227	¢	$564,913	4.227	¢	$564,913
Total	13,425,928	13,425,928	13,364,385	kWh			$1,780,330			$1,997,744
Schedule 80 Employee Discount							$0			($13,498)
Schedule 201 Employee Discount							($141,228)			($141,228)
Total Employee Discount							($445,083)			($499,436)
								Change		($54,353)

PACIFIC POWER
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2023
Forecast 12 Months Ended December 31, 2025

Schedule	Actual 7/22-6/23 Units	Normalized 7/22-6/23 Units	Forecast 1/25 - 12/25 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 23/723 - Composite General Service (Secondary)								
Transmission & Ancillary Services Charge								
per kWh	1,226,088,608	1,198,399,389	1,160,255,186	kWh	0.780 ¢	$9,049,990	1.042 ¢	$12,089,859
System Usage Charge								
Sch 200 related, per kWh	1,226,088,608	1,198,399,389	1,160,255,186	kWh	0.073 ¢	$846,986	0.064 ¢	$742,563
T&A and Sch 201 related, per kWh	1,226,088,608	1,198,399,389	1,160,255,186	kWh	0.106 ¢	$1,229,870	0.128 ¢	$1,485,127
Distribution Charge								
Basic Charge								
Single Phase, per month	787,771	787,771	789,568	bill	$17.35	$13,699,005	$22.10	$17,449,453
Three Phase, per month	247,366	247,366	247,001	bill	$25.90	$6,397,326	$32.95	$8,138,683
Load Size Charge								
≤ 15 kW					No Charge		No Charge	
per kW for all kW in excess of 15 kW	1,174,160	1,174,160	1,136,126	kW	$1.65	$1,874,608	$2.10	$2,385,865
Demand Charge, the first 15 kW of demand					No Charge		No Charge	
Demand Charge, per kW for all kW in excess of 15 kW	575,803	575,803	557,113	kW	$5.40	$3,008,410	$6.87	$3,827,366
Reactive Power Charge, per kvar	214,425	214,425	206,864	kvar	65.00 ¢	$134,462	65.00 ¢	$134,462
Distribution Energy Charge, per kWh	1,226,088,608	1,198,399,389	1,160,255,186	kWh	3.989 ¢	$46,282,579	5.080 ¢	$58,940,963
Energy Charge - Schedule 200								
1st 3,000 kWh, per kWh	960,906,746	938,853,746	909,353,739	kWh	2.804 ¢	$25,498,279	2.610 ¢	$23,734,133
All additional kWh, per kWh	265,181,862	259,545,643	250,901,447	kWh	2.082 ¢	$5,223,768	1.938 ¢	$4,862,470
Subtotal	1,226,088,608	1,198,399,389	1,160,255,186	kWh		$113,245,283		$133,790,944
Renewable Adjustment Clause (202), per kWh	1,226,088,608	1,198,399,389	1,160,255,186	kWh	0.018 ¢	$208,846	0.000 ¢	$0
Insurance Premium Adder- Base (80), per kWh	1,226,088,608	1,198,399,389	1,160,255,186	kWh	0.000 ¢	$0	0.421 ¢	$4,884,674
Subtotal						$113,454,129		$138,675,618
Schedule 201								
1st 3,000 kWh, per kWh	960,906,746	938,853,746	909,353,739	kWh	4.218 ¢	$38,356,541	4.218 ¢	$38,356,541
All additional kWh, per kWh	265,181,862	259,545,643	250,901,447	kWh	3.127 ¢	$7,845,688	3.127 ¢	$7,845,688
Total	1,226,088,608	1,198,399,389	1,160,255,186	kWh		$159,656,358		$184,877,847
							Change	$25,221,489
Schedule No. 23/723 - Composite General Service (Primary)								
Transmission & Ancillary Services Charge								
per kWh	1,955,057	1,955,057	1,877,049	kWh	0.768 ¢	$14,416	1.026 ¢	$19,259
System Usage Charge								
Sch 200 related, per kWh	1,955,057	1,955,057	1,877,049	kWh	0.072 ¢	$1,351	0.063 ¢	$1,183
T&A and Sch 201 related, per kWh	1,955,057	1,955,057	1,877,049	kWh	0.104 ¢	$1,952	0.126 ¢	$2,365
Distribution Charge								
Basic Charge								
Single Phase, per month	211	211	211	bill	$17.35	$3,661	$22.10	$4,663
Three Phase, per month	393	393	392	bill	$25.90	$10,153	$32.95	$12,916
Load Size Charge								
≤ 15 kW					No Charge		No Charge	
per kW for all kW in excess of 15 kW	2,381	2,381	2,278	kW	$1.65	$3,759	$2.10	$4,784
Demand Charge, the first 15 kW of demand					No Charge		No Charge	
Demand Charge, per kW for all kW in excess of 15 kW	1,316	1,316	1,255	kW	$5.33	$6,689	$6.78	$8,509
Reactive Power Charge, per kvar	1,721	1,721	1,654	kvar	60.00 ¢	$992	60.00 ¢	$992
Distribution Energy Charge, per kWh	1,955,057	1,955,057	1,877,049	kWh	3.927 ¢	$73,712	5.001 ¢	$93,871
Energy Charge - Schedule 200								
1st 3,000 kWh, per kWh	1,057,095	1,057,095	1,018,579	kWh	2.761 ¢	$28,123	2.570 ¢	$26,177
All additional kWh, per kWh	897,962	897,962	858,470	kWh	2.050 ¢	$17,599	1.908 ¢	$16,380
Subtotal	1,955,057	1,955,057	1,877,049	kWh		$162,407		$191,099
Renewable Adjustment Clause (202), per kWh	1,955,057	1,955,057	1,877,049	kWh	0.018 ¢	$338	0.000 ¢	$0
Insurance Premium Adder- Base (80), per kWh	1,955,057	1,955,057	1,877,049	kWh	0.000 ¢	$0	0.421 ¢	$7,902
Subtotal						$162,745		$199,001
Schedule 201								
1st 3,000 kWh, per kWh	1,057,095	1,057,095	1,018,579	kWh	4.090 ¢	$41,660	4.090 ¢	$41,660
All additional kWh, per kWh	897,962	897,962	858,470	kWh	3.033 ¢	$26,037	3.033 ¢	$26,037
Total	1,955,057	1,955,057	1,877,049	kWh		$230,442		$266,698
							Change	$36,256

PACIFIC POWER
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2023
Forecast 12 Months Ended December 31, 2025

Schedule	Actual 7/22-6/23 Units	Normalized 7/22-6/23 Units	Forecast 1/25 - 12/25 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 28/728 - Composite								
Large General Service - (Secondary)								
Transmission & Ancillary Services Charge								
per kW	8,582,972	8,582,972	8,570,763	kW	$2.13	$18,255,725	$1.74	$14,913,128
System Usage Charge								
Sch 200 related, per kWh	2,085,565,751	2,044,568,075	2,043,261,478	kWh	0.072 ¢	$1,471,148	0.067 ¢	$1,368,985
T&A and Sch 201 related, per kWh	2,085,565,751	2,044,568,075	2,043,261,478	kWh	0.104 ¢	$2,124,992	0.126 ¢	$2,574,509
Distribution Charge								
Basic Charge								
Load Size ≤ 50 kW, per month	58,094	58,094	59,242	bill	$18.00	$1,066,356	$25.00	$1,481,050
Load Size 51-100 kW, per month	42,437	42,437	43,244	bill	$34.00	$1,470,296	$47.00	$2,032,468
Load Size 101-300 kW, per month	23,536	23,536	23,972	bill	$81.00	$1,941,732	$111.00	$2,660,892
Load Size > 300 kW, per month	719	719	733	bill	$114.00	$83,562	$156.00	$114,348
Load Size Charge								
≤ 50 kW, per kW	2,240,586	2,240,586	2,240,880	kW	$1.15	$2,577,012	$1.60	$3,585,408
51-100 kW, per kW	2,980,722	2,980,722	2,975,675	kW	$0.90	$2,678,108	$1.25	$3,719,594
101-300 kW, per kW	3,587,692	3,587,692	3,579,714	kW	$0.55	$1,968,843	$0.75	$2,684,786
>300 kW, per kW	314,004	314,004	313,436	kW	$0.35	$109,703	$0.50	$156,718
Demand Charge, per kW	8,582,972	8,582,972	8,570,763	kW	$3.87	$33,168,853	$5.31	$45,510,752
Reactive Power Charge, per kvar	612,785	612,785	606,848	kvar	65.00 ¢	$394,451	65.00 ¢	$394,451
Distribution Energy Charge, per kWh	2,085,565,751	2,044,568,075	2,043,261,478	kWh	0.392 ¢	$8,009,585	0.536 ¢	$10,951,882
Energy Charge - Schedule 200								
All kWh, per kWh	2,085,565,751	2,044,568,075	2,043,261,478	kWh	2.615 ¢	$53,431,288	2.445 ¢	$49,957,743
Subtotal	2,085,565,751	2,044,568,075	2,043,261,478	kWh		$128,751,654		$142,106,714
Renewable Adjustment Clause (202), per kWh	2,085,565,751	2,044,568,075	2,043,261,478	kWh	0.018 ¢	$367,787	0.000 ¢	$0
Insurance Premium Adder- Base (80), per kWh	2,085,565,751	2,044,568,075	2,043,261,478	kWh	0.000 ¢	$0	0.296 ¢	$6,048,054
Subtotal						$129,119,441		$148,154,768
Schedule 201								
All kWh, per kWh	2,085,565,751	2,044,568,075	2,043,261,478	kWh	3.932 ¢	$80,341,041	3.932 ¢	$80,341,041
Total	2,085,565,751	2,044,568,075	2,043,261,478	kWh		$209,460,482		$228,495,809
							Change	$19,035,327
Schedule No. 28/728 - Composite								
Large General Service - (Primary)								
Transmission & Ancillary Services Charge								
per kW	70,611	70,611	69,598	kW	$1.67	$116,229	$2.13	$148,244
System Usage Charge								
Sch 200 related, per kWh	21,808,533	21,808,533	21,450,524	kWh	0.070 ¢	$15,015	0.060 ¢	$12,870
T&A and Sch 201 related, per kWh	21,808,533	21,808,533	21,450,524	kWh	0.102 ¢	$21,880	0.111 ¢	$23,810
Distribution Charge								
Basic Charge								
Load Size ≤ 50 kW, per month	122	122	124	bill	$18.00	$2,232	$35.00	$4,340
Load Size 51-100 kW, per month	193	193	194	bill	$31.00	$6,014	$60.00	$11,640
Load Size 101-300 kW, per month	339	339	344	bill	$71.00	$24,424	$138.00	$47,472
Load Size > 300 kW, per month	48	48	48	bill	$101.00	$4,848	$197.00	$9,456
Load Size Charge								
≤ 50 kW, per kW	4,691	4,691	4,657	kW	$1.00	$4,657	$1.95	$9,081
51-100 kW, per kW	14,503	14,503	14,170	kW	$0.80	$11,336	$1.55	$21,964
101-300 kW, per kW	63,140	63,140	62,442	kW	$0.50	$31,221	$0.95	$59,320
>300 kW, per kW	21,330	21,330	20,680	kW	$0.25	$5,170	$0.50	$10,340
Demand Charge, per kW	70,611	70,611	69,598	kW	$3.48	$242,201	$6.78	$471,874
Reactive Power Charge, per kvar	7,845	7,845	7,699	kvar	60.00 ¢	$4,619	60.00 ¢	$4,619
Distribution Energy Charge, per kWh	21,808,533	21,808,533	21,450,524	kWh	0.038 ¢	$8,151	0.103 ¢	$22,094
Energy Charge - Schedule 200								
All kWh, per kWh	21,808,533	21,808,533	21,450,524	kWh	2.554 ¢	$547,846	2.371 ¢	$508,592
Subtotal	21,808,533	21,808,533	21,450,524	kWh		$1,045,843		$1,365,716
Renewable Adjustment Clause (202), per kWh	21,808,533	21,808,533	21,450,524	kWh	0.018 ¢	$3,861	0.000 ¢	$0
Insurance Premium Adder- Base (80), per kWh	21,808,533	21,808,533	21,450,524	kWh	0.000 ¢	$0	0.296 ¢	$63,494
Subtotal						$1,049,704		$1,429,210
Schedule 201								
All kWh, per kWh	21,808,533	21,808,533	21,450,524	kWh	3.842 ¢	$824,129	3.842 ¢	$824,129
Total	21,808,533	21,808,533	21,450,524	kWh		$1,873,833		$2,253,339
							Change	$379,506

PACIFIC POWER
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2023
Forecast 12 Months Ended December 31, 2025

Schedule	Actual 7/22-6/23 Units	Normalized 7/22-6/23 Units	Forecast 1/25 - 12/25 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 30/730 - Composite								
Large General Service - (Secondary)								
Transmission & Ancillary Services Charge								
per kW	3,518,544	3,518,544	3,582,710	kW	$2.52	$9,028,429	$2.45	$8,777,640
System Usage Charge								
Sch 200 related, per kWh	1,249,187,259	1,226,112,463	1,252,474,015	kWh	0.070 ¢	$876,732	0.065 ¢	$814,108
T&A and Sch 201 related, per kWh	1,249,187,259	1,226,112,463	1,252,474,015	kWh	0.101 ¢	$1,264,999	0.121 ¢	$1,515,494
Distribution Charge								
Basic Charge								
Load Size ≤ 200 kW, per month	158	158	159	bill	$436.00	$69,324	$704.00	$111,936
Load Size 201-300 kW, per month	2,505	2,505	2,529	bill	$126.00	$318,654	$204.00	$515,916
Load Size > 300 kW, per month	6,922	6,922	6,990	bill	$334.00	$2,334,660	$541.00	$3,781,590
Load Size Charge								
≤ 200 Kw, per kW					No Charge	$0	No Charge	$0
201-300 kW, per kW	651,402	651,402	665,587	kW	$1.55	$1,031,660	$2.50	$1,663,968
>300 kW, per kW	3,510,622	3,510,622	3,575,964	kW	$0.75	$2,681,973	$1.20	$4,291,157
Demand Charge, per kW	3,518,544	3,518,544	3,582,710	kW	$3.66	$13,112,719	$5.92	$21,209,643
Reactive Power Charge, per kvar	593,103	593,103	593,199	kvar	65.00 ¢	$385,579	65.00 ¢	$385,579
Energy Charge - Schedule 200								
Demand Charge, per kW	3,518,544	3,518,544	3,582,710	kW	$5.80	$20,779,718	$5.39	$19,310,807
All kWh, per kWh	1,249,187,259	1,226,112,463	1,252,474,015	kWh	0.930 ¢	$11,648,008	0.888 ¢	$11,121,969
Subtotal	1,249,187,259	1,226,112,463	1,252,474,015	kWh		$63,532,455		$73,499,807
Renewable Adjustment Clause (202), per kWh	1,249,187,259	1,226,112,463	1,252,474,015	kWh	0.018 ¢	$225,445	0.000 ¢	$0
Insurance Premium Adder- Base (80), per kWh	1,249,187,259	1,226,112,463	1,252,474,015	kWh	0.000 ¢	$0	0.264 ¢	$3,306,531
Subtotal						$63,757,900		$76,806,338
Schedule 201								
All kWh, per kWh	1,249,187,259	1,226,112,463	1,252,474,015	kWh	3.856 ¢	$48,295,398	3.856 ¢	$48,295,398
Total	1,249,187,259	1,226,112,463	1,252,474,015	kWh		$112,053,298		$125,101,736
							Change	$13,048,438
Schedule No. 30/730 - Composite								
Large General Service - (Primary)								
Transmission & Ancillary Services Charge								
per kW	224,316	224,316	227,103	kW	$2.55	$579,113	$2.29	$520,066
System Usage Charge								
Sch 200 related, per kWh	76,532,211	76,532,211	77,804,770	kWh	0.070 ¢	$54,463	0.065 ¢	$50,573
T&A and Sch 201 related, per kWh	76,532,211	76,532,211	77,804,770	kWh	0.102 ¢	$79,361	0.121 ¢	$94,144
Distribution Charge								
Basic Charge								
Load Size ≤ 200 kW, per month	0	0	0	bill	$409.00	$0	$642.00	$0.00
Load Size 201-300 kW, per month	48	48	48	bill	$129.00	$6,192	$202.00	$9,696.00
Load Size > 300 kW, per month	438	438	443	bill	$337.00	$149,291	$527.00	$233,461.00
Load Size Charge								
≤ 200 Kw, per kW					No Charge		No Charge	
201-300 kW, per kW	12,560	12,560	12,952	kW	$1.40	$18,133	$2.20	$28,494
>300 kW, per kW	254,858	254,858	258,240	kW	$0.70	$180,768	$1.10	$284,064
Demand Charge, per kW	224,316	224,316	227,103	kW	$3.57	$810,758	$5.59	$1,269,506
Reactive Power Charge, per kvar	36,888	36,888	35,946	kvar	60.00 ¢	$21,568	60.00 ¢	$21,568
Energy Charge - Schedule 200								
Demand Charge, per kW	224,316	224,316	227,103	kW	$5.80	$1,317,197	$5.24	$1,190,020
All kWh, per kWh	76,532,211	76,532,211	77,804,770	kWh	0.898 ¢	$698,687	0.826 ¢	$642,667
Subtotal	76,532,211	76,532,211	77,804,770	kWh		$3,915,531		$4,344,259
Renewable Adjustment Clause (202), per kWh	76,532,211	76,532,211	77,804,770	kWh	0.018 ¢	$14,005	0.000 ¢	$0
Insurance Premium Adder- Base (80), per kWh	76,532,211	76,532,211	77,804,770	kWh	0.000 ¢	$0	0.264 ¢	$205,405
Subtotal						$3,929,536		$4,549,664
Schedule 201								
All kWh, per kWh	76,532,211	76,532,211	77,804,770	kWh	3.843 ¢	$2,990,037	3.843 ¢	$2,990,037
Total	76,532,211	76,532,211	77,804,770	kWh		$6,919,573		$7,539,701
							Change	$620,128

PACIFIC POWER
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2023
Forecast 12 Months Ended December 31, 2025

Schedule	Actual 7/22-6/23 Units	Normalized 7/22-6/23 Units	Forecast 1/25 - 12/25 Units		Present Price		Present Dollars	Proposed Price		Proposed Dollars
Schedule No. 41/741 - Irrigation										
Agricultural Pumping Service (Secondary)										
Transmission & Ancillary Services Charge										
per kWh	196,326,232	171,439,514	234,909,530	kWh	0.677	¢	$1,590,338	0.660	¢	$1,550,403
System Usage Charge										
Sch 200 related, per kWh	196,326,232	171,439,514	234,909,530	kWh	0.069	¢	$162,088	0.058	¢	$136,248
T&A and Sch 201 related, per kWh	196,326,232	171,439,514	234,909,530	kWh	0.099	¢	$232,560	0.107	¢	$251,353
Distribution Charge										
Basic Charge (billed in November)										
Load Size ≤ 50 kW, or Single Phase Any Size	5,221	5,221	5,155	bill	No Charge		$0	No Charge		$0
Three Phase Load Size 51 - 300 kW, per customer	910	910	899	bill	$410.00		$368,590	$580.00		$521,420
Three Phase Load Size > 300 kW, per customer	19	19	19	bill	$1,620.00		$30,780	$2,300.00		$43,700
Total Annual Bills	6,150	6,150	6,073							
Average Customers	7,984	7,984	7,884							
Monthly Bills	40,234	40,234	39,729							
Load Size Charge (billed in November)										
Single Phase Any Size, Three Phase ≤ 50 kW	85,192	85,192	116,732	kW	$17.10		$1,996,117	$24.20		$2,824,914
Three Phase Load Size 51-300 kW, per kW	81,745	81,745	112,008	kW	$11.70		$1,310,494	$16.60		$1,859,333
Three Phase Load Size > 300 kW, per kW	8,090	8,090	11,085	kW	$7.20		$79,812	$10.20		$113,067
Single Phase, Minimum Charge	408	408	403	bill	$75.00		$30,225	$105.00		$42,315
Three Phase, Minimum Charge	1,756	1,756	1,734	bill	$120.00		$208,080	$170.00		$294,780
Distribution Energy Charge, per kWh	196,326,232	171,439,514	234,909,530	kWh	4.950	¢	$11,628,022	7.049	¢	$16,558,773
Reactive Power Charge, per kvar	170,466	170,466	233,576	kvar	65.00	¢	$151,824	65.00	¢	$151,824
Energy Charge - Schedule 200										
All kWh, per kWh	196,326,232	171,439,514	234,909,530	kWh	2.526	¢	$5,933,815	2.346	¢	$5,510,978
Subtotal	196,326,232	171,439,514	234,909,530	kWh			$23,722,745			$29,859,108
Renewable Adjustment Clause (202), per kWh	196,326,232	171,439,514	234,909,530	kWh	0.017	¢	$39,935	0.000	¢	$0
Insurance Premium Adder- Base (80), per kWh	196,326,232	171,439,514	234,909,530	kWh	0.000	¢	$0	0.449	¢	$1,054,744
Subtotal							$23,762,680			$30,913,852
Schedule 201										
All kWh, per kWh	196,326,232	171,439,514	234,909,530	kWh	3.799	¢	$8,924,213	3.799	¢	$8,924,213
Option A Summer On Peak Adder, per On-peak kWh	0	0	11,109,862	kWh	4.989	¢	$0	12.030	¢	$1,336,516
Option B Summer On Peak Adder, per On-peak kWh	0	0	11,082,022	kWh	4.989	¢	$0	12.030	¢	$1,333,167
Summer Off Peak Adder, per Off-peak kWh	0	0	99,032,240	kWh	-0.992	¢	$0	-2.696	¢	($2,669,909)
Total	196,326,232	171,439,514	234,909,530	kWh			$32,686,893			$39,837,839
								Change		$7,150,946

Schedule	Actual 7/22-6/23 Units	Normalized 7/22-6/23 Units	Forecast 1/25 - 12/25 Units		Present Price		Present Dollars	Proposed Price		Proposed Dollars
Schedule No. 41/741 - Irrigation										
Agricultural Pumping Service (Primary)										
Transmission & Ancillary Services Charge										
per kWh	0	0	0	kWh	0.667	¢	$0	0.650	¢	$0
System Usage Charge										
Sch 200 related, per kWh	0	0	0	kWh	0.068	¢	$0	0.057	¢	$0
T&A and Sch 201 related, per kWh	0	0	0	kWh	0.097	¢	$0	0.105	¢	$0
Distribution Charge										
Basic Charge (billed in November)										
Load Size ≤ 50 kW, or Single Phase Any Size	0	0	0	bill	No Charge		$0	No Charge		$0
Three Phase Load Size 51 - 300 kW, per customer	0	0	0	bill	$400.00		$0	$570.00		$0
Three Phase Load Size > 300 kW, per customer	0	0	0	bill	$1,600.00		$0	$2,270.00		$0
Total Annual Bills	0	0	0							
Average Customers	0	0	0							
Monthly Bills	0	0	0							
Load Size Charge (billed in November)										
Single Phase Any Size, Three Phase ≤ 50 kW	0	0	0	kW	$16.90		$0	$23.90		$0
Three Phase Load Size 51-300 kW, per kW	0	0	0	kW	$11.50		$0	$16.40		$0
Three Phase Load Size > 300 kW, per kW	0	0	0	kW	$7.10		$0	$10.10		$0
Single Phase, Minimum Charge	0	0	0	bill	$75.00		$0	$105.00		$0
Three Phase, Minimum Charge	0	0	0	bill	$120.00		$0	$170.00		$0
Distribution Energy Charge, per kWh	0	0	0	kWh	4.873	¢	$0	6.940	¢	$0
Reactive Power Charge, per kvar	0	0	0	kvar	60.00	¢	$0	60.00	¢	$0
Energy Charge - Schedule 200										
All kWh, per kWh	0	0	0	kWh	2.487	¢	$0	2.310	¢	$0
Subtotal	0	0	0	kWh			$0			$0
Renewable Adjustment Clause (202), per kWh	0	0	0	kWh	0.017	¢	$0	0.000	¢	$0
Insurance Premium Adder- Base (80), per kWh	0	0	0	kWh	0.000	¢	$0	0.449	¢	$0
Subtotal							$0			$0
Schedule 201										
All kWh, per kWh	0	0	0	kWh	3.739	¢	$0	3.739	¢	$0
Option A Summer On Peak Adder, per On-peak kWh	0	0	0	kWh	4.989	¢	$0	12.030	¢	$0
Option B Summer On Peak Adder, per On-peak kWh	0	0	0	kWh	4.989	¢	$0	12.030	¢	$0
Summer Off Peak Adder, per Off-peak kWh	0	0	0	kWh	-0.992	¢	$0	-2.696	¢	$0
Total	0	0	0	kWh			$0			$0
								Change		$0

PACIFIC POWER
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2023
Forecast 12 Months Ended December 31, 2025

Schedule	Actual 7/22-6/23 Units	Normalized 7/22-6/23 Units	Forecast 1/25 - 12/25 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	166,370	166,370	158,737	kW	$2.45	$388,906	$2.73	$433,352
credit per kW of on-peak demand (OATT)	0	0	0	kW	($2.45)	$0	($2.73)	$0
System Usage Charge								
Sch 200 related, per kWh	34,535,247	34,535,247	32,950,858	kWh	0.067 ¢	$22,077	0.061 ¢	$20,100
T&A and Sch 201 related, per kWh	34,535,247	34,535,247	32,950,858	kWh	0.096 ¢	$31,633	0.113 ¢	$37,234
Distribution Charge								
Basic Charge								
Facility Capacity ≤ 4,000 kW, per month	0	0	0	bill	$570.00	$0	$1,160.00	$0
Facility Capacity > 4,000 kW, per month	24	24	24	bill	$1,570.00	$37,680	$3,190.00	$76,560
Facilities Charge								
Facility Capacity ≤ 4,000 kW, per kW	0	0	0	kW	$1.25	$0	$1.35	$0
Facility Capacity > 4,000 kW, per kW	238,892	238,892	227,932	kW	$0.50	$113,966	$0.55	$125,363
Demand Charge, per kW of on-peak demand	166,370	166,370	158,737	kW	$3.46	$549,230	$7.95	$1,261,959
Reactive Power Charge, per kvar	1,829	1,829	1,745	kvar	60.00 ¢	$1,047	60.00 ¢	$1,047
Reactive Hours, per kvarh	5,840,000	5,840,000	5,572,076	kvarh	0.080 ¢	$4,458	0.080 ¢	$4,458
Reserves Charges								
Spinning Reserves, per kW of Facility Cap.	238,892	238,892	227,932	kW	$0.27	$61,542	$0.27	$61,542
Supplemental Reserves, per kW of Facility Cap.	238,892	238,892	227,932	kW	$0.27	$61,542	$0.27	$61,542
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	166,370	166,370	158,737	kW	$1.65	$261,916	$1.52	$241,280
On-Peak, per on-peak kWh	13,996,483	13,996,483	13,354,360	kWh	2.156 ¢	$287,920	1.991 ¢	$265,885
Off-Peak, per off-peak kWh	20,538,764	20,538,764	19,596,498	kWh	2.156 ¢	$422,500	1.991 ¢	$390,166
Unscheduled Energy, per kWh	4,037,353	4,037,353	3,852,130	kWh		$372,143		$372,143
Subtotal	38,572,600	38,572,600	36,802,988	kWh		$2,616,560		$3,352,631
Renewable Adjustment Clause (202), per kWh	38,572,600	38,572,600	36,802,988	kWh	0.017 ¢	$6,257	0.000 ¢	$0
Insurance Premium Adder- Base (80), per kWh	38,572,600	38,572,600	36,802,988	kWh	0.000 ¢	$0	0.225 ¢	$82,807
Subtotal						$2,622,817		$3,435,438
Schedule 201								
On-Peak, per on-peak kWh	13,996,483	13,996,483	13,354,360	kWh	4.500 ¢	$600,946	4.500 ¢	$600,946
Off-Peak, per off-peak kWh	20,538,764	20,538,764	19,596,498	kWh	3.195 ¢	$626,108	3.195 ¢	$626,108
Total	38,572,600	38,572,600	36,802,988	kWh		$3,849,871		$4,662,492
							Change	$812,621
Schedule No. 47/747 - Composite								
Large General Service - Partial Requirement (Transmission)								
Transmission & Ancillary Services Charge								
per kW of on-peak demand	69,839	69,839	57,787	kW	$3.11	$179,718	$3.13	$180,873
credit per kW of on-peak demand (OATT)	0	0	0	kW	($3.11)	$0	($3.13)	$0
System Usage Charge								
Sch 200 related, per kWh	6,633,968	6,633,968	6,144,492	kWh	0.065 ¢	$3,994	0.059 ¢	$3,625
T&A and Sch 201 related, per kWh	6,633,968	6,633,968	6,144,492	kWh	0.091 ¢	$5,591	0.109 ¢	$6,697
Distribution Charge								
Basic Charge								
Facility Capacity ≤ 4,000 kW, per month	24	24	24	bill	$710.00	$17,040	$1,770.00	$42,480
Facility Capacity > 4,000 kW, per month	24	24	24	bill	$1,820.00	$43,680	$4,550.00	$109,200
Facilities Charge								
Facility Capacity ≤ 4,000 kW, per kW	29,508	29,508	28,154	kW	$1.25	$35,193	$1.35	$38,008
Facility Capacity > 4,000 kW, per kW	201,492	201,492	168,755	kW	$1.05	$177,193	$1.15	$194,068
Demand Charge, per kW of on-peak demand	69,839	69,839	57,787	kW	$1.85	$106,906	$6.21	$358,857
Reactive Power Charge, per kvar	42,521	42,521	33,459	kvar	55.00 ¢	$18,402	55.00 ¢	$18,402
Reactive Hours, per kvarh	5,610,565	5,610,565	4,314,591	kvarh	0.080 ¢	$3,452	0.080 ¢	$3,452
Reserves Charges								
Spinning Reserves, per kW of Facility Cap.	231,000	231,000	196,909	kW	$0.27	$53,165	$0.27	$53,165
Supplemental Reserves, per kW of Facility Cap.	231,000	231,000	196,909	kW	$0.27	$53,165	$0.27	$53,165
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	69,839	69,839	57,787	kW	$1.68	$97,082	$1.54	$88,992
On-Peak, per on-peak kWh	2,353,417	2,353,417	2,171,379	kWh	2.077 ¢	$45,100	1.908 ¢	$41,430
Off-Peak, per off-peak kWh	4,280,551	4,280,551	3,973,113	kWh	2.077 ¢	$82,522	1.908 ¢	$75,807
Unscheduled Energy, per kWh	463,281	463,281	431,196	kWh		$60,119		$60,119
Subtotal	7,097,249	7,097,249	6,575,688	kWh		$982,322		$1,328,340
Renewable Adjustment Clause (202), per kWh	7,097,249	7,097,249	6,575,688	kWh	0.017 ¢	$1,118	0.000 ¢	$0
Insurance Premium Adder- Base (80), per kWh	7,097,249	7,097,249	6,575,688	kWh	0.000 ¢	$0	0.225 ¢	$14,795
Subtotal						$983,440		$1,343,135
Schedule 201								
On-Peak, per on-peak kWh	2,353,417	2,353,417	2,171,379	kWh	4.358 ¢	$94,629	4.358 ¢	$94,629
Off-Peak, per off-peak kWh	4,280,551	4,280,551	3,973,113	kWh	3.031 ¢	$120,425	3.031 ¢	$120,425
Total	7,097,249	7,097,249	6,575,688	kWh		$1,198,494		$1,558,189
							Change	$359,695
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	$0.081	$0
Primary	0	0	0	kW	$0.095	$0	$0.106	$0
Transmission	0	0	0	kW	$0.121	$0	$0.122	$0
Daily ERP Demand Charge, per kW of Daily ERP On-Peak Demand								
Secondary	0	0	0	kW	$0.128	$0	$0.250	$0
Primary	0	0	0	kW	$0.135	$0	$0.310	$0
Transmission	0	0	0	kW	$0.072	$0	$0.242	$0

PACIFIC POWER
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2023
Forecast 12 Months Ended December 31, 2025

Schedule	Actual 7/22-6/23 Units	Normalized 7/22-6/23 Units	Forecast 1/25 - 12/25 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 48/748 - Composite								
Large General Service (Secondary)								
Transmission & Ancillary Services Charge								
per kW of on-peak demand	1,357,579	1,357,579	1,456,129	kW	$2.78	$4,048,039	$2.61	$3,800,497
System Usage Charge								
Sch 200 related, per kWh	571,527,962	534,576,675	570,907,617	kWh	0.070 ¢	$399,635	0.066 ¢	$376,799
T&A and Sch 201 related, per kWh	571,527,962	534,576,675	570,907,617	kWh	0.100 ¢	$570,908	0.122 ¢	$696,507
Distribution Charge								
Basic Charge								
Facility Capacity ≤ 4,000 kW, per month	967	967	979	bill	$580.00	$567,820	$820.00	$802,780
Facility Capacity > 4,000 kW, per month	47	47	48	bill	$1,600.00	$76,800	$2,260.00	$108,480
Facilities Charge								
Facility Capacity ≤ 4,000 kW, per kW	1,366,564	1,366,564	1,474,868	kW	$2.95	$4,350,861	$2.60	$3,834,657
Facility Capacity > 4,000 kW, per kW	321,484	321,484	351,447	kW	$1.15	$404,164	$1.00	$351,447
Demand Charge, per kW of on-peak demand	1,357,579	1,357,579	1,456,129	kW	$3.28	$4,776,103	$6.42	$9,348,348
Reactive Power Charge, per kvar	357,661	357,661	367,191	kvar	65.00 ¢	$238,674	65.00 ¢	$238,674
Energy Charge - Schedule 200								
Demand Charge, per kW of On-Peak demand	1,357,579	1,357,579	1,456,129	kW	$1.57	$2,286,123	$1.45	$2,111,387
On-Peak, per on-peak kWh	218,180,840	203,881,840	218,085,760	kWh	2.154 ¢	$4,697,567	1.989 ¢	$4,337,726
Off-Peak, per off-peak kWh	353,347,122	330,694,835	352,821,857	kWh	2.154 ¢	$7,599,783	1.989 ¢	$7,017,627
Subtotal	571,527,962	534,576,675	570,907,617	kWh		$30,016,477		$33,024,929
Renewable Adjustment Clause (202), per kWh	571,527,962	534,576,675	570,907,617	kWh	0.017 ¢	$97,054	0.000 ¢	$0
Insurance Premium Adder- Base (80), per kWh	571,527,962	534,576,675	570,907,617	kWh	0.000 ¢	$0	0.225 ¢	$1,284,542
Subtotal						$30,113,531		$34,309,471
Schedule 201								
On-Peak, per on-peak kWh	218,180,840	203,881,840	218,085,760	kWh	4.625 ¢	$10,086,466	4.625 ¢	$10,086,466
Off-Peak, per off-peak kWh	353,347,122	330,694,835	352,821,857	kWh	3.333 ¢	$11,759,552	3.333 ¢	$11,759,552
Total	571,527,962	534,576,675	570,907,617	kWh		$51,959,549		$56,155,489
							Change	$4,195,940
Schedule No. 48/748 - Composite								
Large General Service (Primary)								
Transmission & Ancillary Services Charge								
per kW of on-peak demand	2,868,329	2,868,329	4,143,758	kW	$2.99	$12,389,836	$3.27	$13,550,089
System Usage Charge								
Sch 200 related, per kWh	1,349,307,157	1,346,524,569	2,171,322,968	kWh	0.067 ¢	$1,454,786	0.061 ¢	$1,324,507
T&A and Sch 201 related, per kWh	1,349,307,157	1,346,524,569	2,171,322,968	kWh	0.096 ¢	$2,084,470	0.113 ¢	$2,453,595
Distribution Charge								
Basic Charge								
Facility Capacity ≤ 4,000 kW, per month	692	692	701	bill	$570.00	$399,570	$1,160.00	$813,160
Facility Capacity > 4,000 kW, per month	294	294	305	bill	$1,570.00	$478,850	$3,190.00	$972,950
Facilities Charge								
Facility Capacity ≤ 4,000 kW, per kW	1,405,842	1,405,842	1,520,080	kW	$1.25	$1,900,100	$1.35	$2,052,108
Facility Capacity > 4,000 kW, per kW	2,137,522	2,137,522	3,334,729	kW	$0.50	$1,667,365	$0.55	$1,834,101
Demand Charge, per kW of on-peak demand	2,868,329	2,868,329	4,143,758	kW	$3.46	$14,337,403	$7.95	$32,942,876
Reactive Power Charge, per kvar	649,927	649,927	644,775	kvar	60.00 ¢	$386,865	60.00 ¢	$386,865
Energy Charge - Schedule 200								
Demand Charge, per kW of On-Peak demand	2,868,329	2,868,329	4,143,758	kW	$1.65	$6,837,201	$1.52	$6,298,512
On-Peak, per on-peak kWh	513,849,467	512,824,467	822,791,267	kWh	2.156 ¢	$17,739,380	1.991 ¢	$16,381,774
Off-Peak, per off-peak kWh	835,457,690	833,700,102	1,348,531,701	kWh	2.156 ¢	$29,074,343	1.991 ¢	$26,849,266
Subtotal	1,349,307,157	1,346,524,569	2,171,322,968	kWh		$88,750,169		$105,859,803
Renewable Adjustment Clause (202), per kWh	1,349,307,157	1,346,524,569	2,171,322,968	kWh	0.017 ¢	$369,125	0.000 ¢	$0
Insurance Premium Adder- Base (80), per kWh	1,349,307,157	1,346,524,569	2,171,322,968	kWh	0.000 ¢	$0	0.225 ¢	$4,885,477
Subtotal						$89,119,294		$110,745,280
Schedule 201								
On-Peak, per on-peak kWh	513,849,467	512,824,467	822,791,267	kWh	4.500 ¢	$37,025,607	4.500 ¢	$37,025,607
Off-Peak, per off-peak kWh	835,457,690	833,700,102	1,348,531,701	kWh	3.195 ¢	$43,085,588	3.195 ¢	$43,085,588
Total	1,349,307,157	1,346,524,569	2,171,322,968	kWh		$169,230,489		$190,856,475
							Change	$21,625,986
Schedule No. 48/748 - Composite								
Large General Service (Transmission)								
Transmission & Ancillary Services Charge								
per kW of on-peak demand	1,765,230	1,765,230	2,942,058	kW	$3.65	$10,738,512	$3.67	$10,797,353
System Usage Charge								
Sch 200 related, per kWh	1,156,897,000	1,156,897,000	1,934,879,950	kWh	0.065 ¢	$1,257,672	0.059 ¢	$1,141,579
T&A and Sch 201 related, per kWh	1,156,897,000	1,156,897,000	1,934,879,950	kWh	0.091 ¢	$1,760,741	0.109 ¢	$2,109,019
Distribution Charge								
Basic Charge								
Facility Capacity ≤ 4,000 kW, per month	23	23	24	bill	$710.00	$17,040	$1,770.00	$42,480
Facility Capacity > 4,000 kW, per month	60	60	60	bill	$1,820.00	$109,200	$4,550.00	$273,000
Facilities Charge								
Facility Capacity ≤ 4,000 kW, per kW	22,357	22,357	26,522	kW	$1.25	$33,153	$1.35	$35,805
Facility Capacity > 4,000 kW, per kW	1,855,595	1,855,595	3,095,875	kW	$1.05	$3,250,669	$1.15	$3,560,256
Demand Charge, per kW of on-peak demand	1,765,230	1,765,230	2,942,058	kW	$1.85	$5,442,807	$6.21	$18,270,180
Reactive Power Charge, per kvar	45,999	45,999	54,046	kvar	55.00 ¢	$29,725	55.00 ¢	$29,725
Energy Charge - Schedule 200								
Demand Charge, per kW of On-Peak demand	1,765,230	1,765,230	2,942,058	kW	$1.68	$4,942,657	$1.54	$4,530,769
On-Peak, per on-peak kWh	433,489,000	433,489,000	725,013,625	kWh	2.077 ¢	$15,058,533	1.908 ¢	$13,833,260
Off-Peak, per off-peak kWh	723,408,000	723,408,000	1,209,866,325	kWh	2.077 ¢	$25,128,924	1.908 ¢	$23,084,249
Subtotal	1,156,897,000	1,156,897,000	1,934,879,950	kWh		$67,769,633		$77,707,675
Renewable Adjustment Clause (202), per kWh	1,156,897,000	1,156,897,000	1,934,879,950	kWh	0.017 ¢	$328,930	0.000 ¢	$0
Insurance Premium Adder- Base (80), per kWh	1,156,897,000	1,156,897,000	1,934,879,950	kWh	0.000 ¢	$0	0.225 ¢	$4,353,480
Subtotal						$68,098,563		$82,061,155
Schedule 201								
On-Peak, per on-peak kWh	433,489,000	433,489,000	725,013,625	kWh	4.358 ¢	$31,596,094	4.358 ¢	$31,596,094
Off-Peak, per off-peak kWh	723,408,000	723,408,000	1,209,866,325	kWh	3.031 ¢	$36,671,048	3.031 ¢	$36,671,048
Total	1,156,897,000	1,156,897,000	1,934,879,950	kWh		$136,365,705		$150,328,297
							Change	$13,962,592

PACIFIC POWER
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2023
Forecast 12 Months Ended December 31, 2025

Schedule	Actual 7/22-6/23 Units	Normalized 7/22-6/23 Units	Forecast 1/25 - 12/25 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
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	$1,770.00	$0
Facility Capacity > 4,000 kW, per month	12	12	12	bill	$1,820.00	$21,840	$4,550.00	$54,600
Facilities Charge								
Facility Capacity ≤ 4,000 kW, per kW	0	0	0	kW	$1.25	$0	$1.35	$0
Facility Capacity > 4,000 kW, per kW	396,113	396,113	524,299	kW	$1.05	$550,514	$1.15	$602,944
Demand Charge, per kW of on-peak demand	385,893	385,893	510,772	kW	$1.85	$944,928	$6.21	$3,171,894
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		$1,517,282		$3,829,438
Renewable Adjustment Clause (202), per kWh								
Insurance Premium Adder- Base (80), per kWh	*269,239,000*	*269,239,000*	*335,577,000*	kWh	0.000 ¢	$0	0.225 ¢	$755,048
Subtotal						$1,517,282		$4,584,486
Schedule 201								
On-Peak, per on-peak kWh				kWh				
Off-Peak, per off-peak kWh				kWh				
Total				kWh		$1,517,282		$4,584,486
Energy Delivered	269,239,000	269,239,000	335,577,000				Change	$3,067,204
Schedule No. 15 - Composite								
Outdoor Area Lighting Service								
No. of Customers	5,991	5,991	5,833					
Transmission & Ancillary Services Charge								
per kWh	8,258,382	8,258,382	8,156,574	kWh	0.066 ¢	$5,394	0.051 ¢	$4,193
System Usage Charge								
Sch 200 related, per kWh	8,258,382	8,258,382	8,156,574	kWh	0.026 ¢	$2,143	0.024 ¢	$1,928
T&A and Sch 201 related, per kWh	8,258,382	8,258,382	8,156,574	kWh	0.029 ¢	$2,357	0.032 ¢	$2,572
Distribution Charge								
Distribution Charge, per kWh	8,258,382	8,258,382	8,156,574	kWh	7.857 ¢	$638,246	8.948 ¢	$729,845
Energy Charge - Schedule 200								
per kWh	8,258,382	8,258,382	8,156,574	kWh	0.962 ¢	$78,307	0.742 ¢	$60,540
Subtotal	8,258,382	8,258,382	8,156,574	kWh		$726,447		$799,077
Renewable Adjustment Clause (202), per kWh	8,258,382	8,258,382	8,156,574	kWh	0.014 ¢	$1,142	0.000 ¢	$0
Insurance Premium Adder- Base (80), per kWh	2,159,285	2,159,285	2,127,947	kWh	0.000 ¢	$0	0.630 ¢	$13,406
Subtotal						$727,589		$812,483
Schedule 201								
per kWh	8,258,382	8,258,382	8,156,574	kWh	1.374 ¢	$111,792	1.371 ¢	$111,792
Total	8,258,382	8,258,382	8,156,574	kWh		$839,381		$924,275
							Change	$84,894
Schedule No. 51/751								
Street Lighting Service, Company-Owned System								
No. of Customers	1,194	1,194	1,210					
Transmission & Ancillary Services Charge								
per kWh	23,584,283	23,584,283	20,858,198	kWh	0.084 ¢	$17,569	0.065 ¢	$13,487
System Usage Charge								
Sch 200 related, per kWh	23,584,283	23,584,283	20,858,198	kWh	0.032 ¢	$6,696	0.030 ¢	$6,355
T&A and Sch 201 related, per kWh	23,584,283	23,584,283	20,858,198	kWh	0.047 ¢	$9,836	0.047 ¢	$9,836
Distribution Charge								
Distribution Charge, per kWh	23,584,283	23,584,283	20,858,198	kWh	10.691 ¢	$2,229,901	12.262 ¢	$2,557,571
Energy Charge - Schedule 200								
per kWh	23,584,283	23,584,283	20,858,198	kWh	1.352 ¢	$281,955	1.020 ¢	$212,810
Subtotal	23,584,283	23,584,283	20,858,198	kWh		$2,545,957		$2,800,058
Renewable Adjustment Clause (202), per kWh	23,584,283	23,584,283	20,858,198	kWh	0.014 ¢	$2,920	0.000 ¢	$0
Insurance Premium Adder- Base (80), per kWh	8,930,279	8,930,279	7,898,066	kWh	0.000 ¢	$0	0.630 ¢	$49,758
Subtotal						$2,548,877		$2,849,816
Schedule 201								
per kWh	23,584,283	23,584,283	20,858,198	kWh	1.696 ¢	$353,820	1.696 ¢	$353,820
Total	0	0	20,858,198	kWh		$2,902,697		$3,203,636
							Change	$300,939

PACIFIC POWER
State of Oregon
Billing Determinants
Actual 12 Months Ended June 30, 2023
Forecast 12 Months Ended December 31, 2025

Schedule	Actual 7/22-6/23 Units	Normalized 7/22-6/23 Units	Forecast 1/25 - 12/25 Units		Present Price		Present Dollars	Proposed Price		Proposed Dollars
Schedule No. 53/753										
Street Lighting Service, Consumer-Owned System										
No. of Customers	294	294	296							
Transmission & Ancillary Services Charge										
per kWh	8,075,045	8,075,045	8,821,260	kWh	0.029	¢	$2,558	0.022	¢	$1,941
System Usage Charge										
Sch 200 related, per kWh	8,075,045	8,075,045	8,821,260	kWh	0.012	¢	$1,059	0.010	¢	$882
T&A and Sch 201 related, per kWh	8,075,045	8,075,045	8,821,260	kWh	0.015	¢	$1,323	0.016	¢	$1,411
Distribution Charge										
Distribution Charge, per kWh	8,075,045	8,075,045	8,821,260	kWh	4.262	¢	$324,469	4.212	¢	$371,574
Energy Charge - Schedule 200										
per kWh	8,075,045	8,075,045	8,821,260	kWh	0.449	¢	$39,607	0.349	¢	$30,786
Subtotal	8,075,045	8,075,045	8,821,260	kWh			$369,016			$406,595
Renewable Adjustment Clause (202), per kWh	8,075,045	8,075,045	8,821,260	kWh	0.014	¢	$1,235	0.000	¢	$0
Insurance Premium Adder- Base (80), per kWh	8,075,045	8,075,045	8,821,260	kWh	0.000	¢	$0	0.630	¢	$55,574
Subtotal							$370,251			$462,169
Schedule 201										
per kWh	8,075,045	8,075,045	8,821,260	kWh	1.320	¢	$116,441	1.320	¢	$116,441
Total	8,075,045	8,075,045	8,821,260	kWh			$486,692			$578,609
								Change		$91,918
Schedule No. 54/754										
Recreational Field Lighting										
Transmission & Ancillary Services Charge										
per kWh	1,449,879	1,449,879	1,373,662	kWh	0.037	¢	$508	0.028	¢	$385
System Usage Charge										
Sch 200 related, per kWh	1,449,879	1,449,879	1,373,662	kWh	0.016	¢	$220	0.012	¢	$165
T&A and Sch 201 related, per kWh	1,449,879	1,449,879	1,373,662	kWh	0.020	¢	$275	0.020	¢	$275
Distribution Charge										
Basic Charge, Single Phase, per month	759	759	757	bill	$6.00		$4,542	$6.00		$4,542
Basic Charge, Three Phase, per month	420	420	419	bill	$9.00		$3,771	$9.00		$3,771
Distribution Energy Charge, per kWh	1,449,879	1,449,879	1,373,662	kWh	4.001	¢	$54,960	4.684	¢	$64,342
Energy Charge - Schedule 200										
per kWh	1,449,879	1,449,879	1,373,662	kWh	0.578	¢	$7,940	0.439	¢	$6,030
Subtotal	1,449,879	1,449,879	1,373,662	kWh			$72,216			$79,510
Renewable Adjustment Clause (202), per kWh	1,449,879	1,449,879	1,373,662	kWh	0.014	¢	$192	0.000	¢	$0
Insurance Premium Adder- Base (80), per kWh	1,449,879	1,449,879	1,373,662	kWh	0.000	¢	$0	0.630	¢	$8,654
Subtotal							$72,408			$88,164
Schedule 201										
per kWh	1,449,879	1,449,879	1,373,662	kWh	1.320	¢	$18,132	1.320	¢	$18,132
Total	1,449,879	1,449,879	1,373,662	kWh			$90,540			$106,296
								Change		$15,756
Subtotal Oregon	14,132,701,620	13,680,122,990	15,339,351,516				$1,677,396,895			$1,885,557,483
Employee Discount							($445,083)			($499,436)
TOTAL OREGON	**14,132,701,620**	**13,680,122,990**	**15,339,351,516**				**$1,676,951,812**			**$1,885,058,047**
Distribution Only Energy	269,239,000	269,239,000	335,577,000							
Total Energy Including Distribution Only	14,401,940,620	13,949,361,990	15,674,928,516							

PACIFIC POWER
STATE OF OREGON
Calculation of Proposed Insurance Cost Adjustment - Schedule 80

FORECAST 12 MONTHS ENDED DECEMBER 31, 2025

Line No.	Description	Sch No.	MWh*	Proposed Base Revenues** ($000)	Equal Percentage Rate Spread	Proposed Schedule 80 Base Rates (¢/kWh)	Proposed Schedule 80 Base Revenues ($000)	Proposed Schedule 80 Deferred Rates (¢/kWh)	Proposed Schedule 80 Deferred Revenues ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Residential								
1	Residential	4	5,787,620	$860,844	47.2%	0.404	$23,382	0.125	$7,235
2	**Total Residential**		5,787,620	$860,844			$23,382		$7,235
	Commercial & Industrial								
3	Gen. Svc. < 31 kW	23	1,162,132	$180,252	9.9%	0.421	$4,893	0.130	$1,511
4	Gen. Svc. 31 - 200 kW	28	2,064,712	$224,638	12.3%	0.296	$6,112	0.091	$1,879
5	Gen. Svc. 201 - 999 kW	30	1,330,279	$129,130	7.1%	0.264	$3,512	0.081	$1,078
6	Large General Service >= 1,000 kW	48	4,677,111	$386,817	21.2%	0.225	$10,523	0.069	$3,227
7	Partial Req. Svc. >= 1,000 kW	47	43,379	$6,123		0.225	$98	0.069	$30
8	Dist. Only Lg Gen Svc >= 1,000 kW	848	335,577	$3,829		0.225	$755	0.069	$232
9	Agricultural Pumping Service	41	234,910	$38,783	2.1%	0.449	$1,055	0.138	$324
10	**Total Commercial & Industrial**		9,848,099	$969,571			$26,947		$8,280
	Lighting								
11	Outdoor Area Lighting Service	15	2,128	$911		0.630	$13	0.194	$4
12	Street Lighting Service Comp. Owned	51	7,898	$3,154		0.630	$50	0.194	$15
13	Street Lighting Service Cust. Owned	53	8,821	$523		0.630	$56	0.194	$17
14	Recreational Field Lighting	54	1,374	$98		0.630	$9	0.194	$3
15	**Total Lighting**		20,221	$4,685	0.3%	0.630	$127	0.194	$39
16	**Subtotal**		15,655,940	$1,835,101	100.0%		$50,456		$15,554
17	Emplolyee Discount			($486)			($13)		($4)
18	**Total Sales with Employee Discount**			$1,834,615			$50,443		$15,550

* Includes Distribution Only consumer MWh and lighting tariff MWh
** Proposed Base Revenues prior to inclusion of base Insurance Premium Adder

PACIFIC POWER
STATE OF OREGON
Calculation of Proposed Catastrophic Fire Fund Adjustment - Schedule 193

FORECAST 12 MONTHS ENDED DECEMBER 31, 2025

Line No.	Description	Sch No.	MWh*	Proposed Distribution Revenues ($000)	Distribution Rate Spread	Proposed Schedule 193 Rate (¢/kWh)	Proposed Schedule 193 Revenues ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Residential						
1	Residential	4	5,787,620	$404,433	56.8%	0.764	$44,217
2	**Total Residential**		5,787,620	$404,433			$44,217
	Commercial & Industrial						
3	Gen. Svc. < 31 kW	23	1,162,132	$91,003	12.8%	0.856	$9,948
4	Gen. Svc. 31 - 200 kW	28	2,064,712	$73,965	10.4%	0.392	$8,094
5	Gen. Svc. 201 - 999 kW	30	1,330,279	$33,807	4.8%	0.278	$3,698
6	Large General Service >= 1,000 kW	48	4,677,111	$75,898		0.178	$8,325
7	Partial Req. Svc. >= 1,000 kW	47	43,379	$2,463	11.6%	0.178	$77
8	Dist. Only Lg Gen Svc >= 1,000 kW	848	335,577	$3,829		0.178	$597
9	Agricultural Pumping Service	41	234,910	$22,410	3.1%	1.043	$2,450
10	**Total Commercial & Industrial**		9,848,099	$303,374			$33,190
	Lighting						
11	Outdoor Area Lighting Service	15	2,128	$730	0.1%	3.749	$80
12	Street Lighting Service Comp. Owned	51	7,898	$2,558	0.4%	3.540	$280
13	Street Lighting Service Cust. Owned	53	8,821	$372	0.1%	0.460	$41
14	Recreational Field Lighting	54	1,374	$73	0.0%	0.578	$8
15	**Total Lighting**		20,221	$3,732			$408
16	**Subtotal**		15,655,940	$711,539	100.0%		$77,815
17	Emplolyee Discount			($222)			($26)
18	**Total Sales with Employee Discount**			$711,316			$77,789

* Includes Distribution Only consumer MWh and lighting tariff MWh

PACIFIC POWER
STATE OF OREGON
Calculation of Proposed Addition to Wildfire Mitigation Plan Cost Recovery Adjustment - Schedule 190

FORECAST 12 MONTHS ENDED DECEMBER 31, 2025

Line No.	Description	Sch No.	MWh*	Proposed Distribution Revenues ($000)	Distribution Rate Spread	Proposed Schedule 190 Addition Rate (¢/kWh)	Proposed Schedule 190 Addition Revenues ($000)	Total Proposed 190 Rate (¢/kWh)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Residential							
1	Residential	4	5,787,620	$404,433	56.8%	0.209	$12,096	0.678
2	**Total Residential**		5,787,620	$404,433			$12,096	
	Commercial & Industrial							
3	Gen. Svc. < 31 kW	23	1,162,132	$91,003	12.8%	0.234	$2,719	0.760
4	Gen. Svc. 31 - 200 kW	28	2,064,712	$73,965	10.4%	0.107	$2,209	0.309
5	Gen. Svc. 201 - 999 kW	30	1,330,279	$33,807	4.8%	0.076	$1,011	0.211
6	Large General Service >= 1,000 kW	48	4,677,111	$75,898		0.049	$2,292	0.134
7	Partial Req. Svc. >= 1,000 kW	47	43,379	$2,463	11.6%	0.049	$21	0.134
8	Dist. Only Lg Gen Svc >= 1,000 kW	848	335,577	$3,829		0.049	$164	0.134
9	Agricultural Pumping Service	41	234,910	$22,410	3.1%	0.285	$669	0.841
10	**Total Commercial & Industrial**		9,848,099	$303,374			$9,087	
	Lighting							
11	Outdoor Area Lighting Service	15	2,128	$730	0.1%	1.023	$22	3.612
12	Street Lighting Service Comp. Owned	51	7,898	$2,558	0.4%	0.966	$76	3.481
13	Street Lighting Service Cust. Owned	53	8,821	$372	0.1%	0.126	$11	0.443
14	Recreational Field Lighting	54	1,374	$73	0.0%	0.158	$2	0.553
15	**Total Lighting**		20,221	$3,732			$111	
16	**Subtotal**		15,655,940	$711,539	100.0%		$21,294	
17	Emplolyee Discount			($222)			($7)	
18	**Total Sales with Employee Discount**			$711,316			$21,287	

* Includes Distribution Only consumer MWh and lighting tariff MWh

Docket No. UE 433
Exhibit PAC/1910
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 and Proposed Adjustment Schedules

February 2024

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, 2025

					Present Revenues ($000)			Proposed Revenues ($000)			Change				
											Base Rates		Net Rates		
Line No.	Description	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)	
							(5) + (6)			(8) + (9)	(8) - (5)	(11)/(5)	(10) - (7)	(13)/(7)	
	Residential														
1	Residential	4	513,581	5,787,620	$786,075	$45,954	$832,029	$884,226	$127,212	$1,011,438	$98,151	12.5%	$179,409	21.6%	1
2	**Total Residential**		513,581	5,787,620	$786,075	$45,954	$832,029	$884,226	$127,212	$1,011,438	$98,151	12.5%	$179,409	21.6%	2
	Commercial & Industrial														
3	Gen. Svc. < 31 kW	23	86,033	1,162,132	$159,887	$10,366	$170,253	$185,145	$23,173	$208,317	$25,258	15.8%	$38,064	22.4%	3
4	Gen. Svc. 31 - 200 kW	28	10,658	2,064,712	$211,334	$25,644	$236,978	$230,749	$30,764	$261,513	$19,415	9.2%	$24,535	10.4%	4
5	Gen. Svc. 201 - 999 kW	30	847	1,330,279	$118,973	$14,740	$133,713	$132,641	$16,217	$148,858	$13,669	11.5%	$15,145	11.3%	5
6	Large General Service >= 1,000 kW	48	177	4,677,111	$357,556	$19,276	$376,831	$397,340	$32,091	$429,431	$39,785	11.3%	$52,600	14.1%	6
7	Partial Req. Svc. >= 1,000 kW	47	6	43,379	$5,048	$179	$5,228	$6,221	$298	$6,519	$1,172	11.3%	$1,291	14.1%	7
8	Dist. Only Lg Gen Svc >= 1,000 kW	848	1	0	$1,517	$547	$2,064	$4,584	$1,540	$6,125	$3,067	202.2%	$4,061	196.7%	8
9	Agricultural Pumping Service	41	7,884	234,910	$32,687	($1,212)	$31,475	$39,838	($1,308)	$38,529	$7,151	21.9%	$7,055	22.4%	9
10	**Total Commercial & Industrial**		105,606	9,512,522	$887,002	$69,540	$956,542	$996,518	$102,774	$1,099,293	$109,516	12.3%	$142,751	14.9%	10
	Lighting														
11	Outdoor Area Lighting Service	15	5,833	8,157	$839	$315	$1,154	$924	$282	$1,206	$85	10.1%	$52	4.5%	11
12	Street Lighting Service Comp. Owned	51	1,210	20,858	$2,903	$1,229	$4,132	$3,204	$1,113	$4,317	$301	10.4%	$185	4.5%	12
13	Street Lighting Service Cust. Owned	53	296	8,821	$487	$293	$780	$579	$237	$815	$92	18.9%	$35	4.5%	13
14	Recreational Field Lighting	54	98	1,374	$91	$58	$148	$106	$49	$155	$16	17.4%	$7	4.5%	14
15	**Total Public Street Lighting**		7,437	39,210	$4,319	$1,896	$6,215	$4,813	$1,681	$6,493	$494	11.4%	$278	4.5%	15
16	**Subtotal**		626,624	15,339,352	$1,677,397	$117,389	$1,794,786	$1,885,557	$231,667	$2,117,224	$208,161	12.4%	$322,439	18.0%	16
17	Emplolyee Discount		*867*	*13,364*	($445)	($27)	($472)	($499)	($73)	($573)	($54)		($101)		17
18	Paperless Credit				($1,855)		($1,855)	($1,855)		($1,855)	$0		$0		18
19	AGA Revenue				$4,071		$4,071	$4,071		$4,071	$0		$0		19
20	COOC Amortization				$1,769		$1,769	$1,769		$1,769	$0		$0		20
21	**Total**		626,624	15,339,352	$1,680,937	$117,362	$1,798,299	$1,889,043	$231,593	$2,120,637	$208,106	12.4%	$322,337	17.9%	21

[1] Excludes effects of the low income assistance charges (Sch. 91 and Sch. 92), 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, 2025

Line No.	Description	Pre Sch No.	Def. Insur. 80 ($000)	WMVM Adj 94 ($000)	Prop Sls. Adj 96 ($000)	Intv. Fndg Adj 97 ($000)	WMP Def Adj 190 ($000)	WMP Def Adj 190 ($000)	Def Acct Adj 192 ($000)	Cat Wildf Adj 193 ($000)	Repl Mtr Def Adj 194 ($000)	Deer Cr Def Adj 198 ($000)	RAC Defer. 203 ($000)	Sol. Inctv. 204 ($000)	PCAM 206 ($000)	Comm. Sol 207 ($000)	RMA 299 ($000)	RMA 299 ($000)	Total ($000)	Total ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)
			PRO				PRE	PRO		PRO							PRE	PRO	PRE	PRO
	Residential																			
1	Residential	4	$7,235	$15,684	$1,158	$1,794	$27,144	$39,240	$3,530	$44,217	$1,910	$868	$3,299	$984	$6,598	$695	($17,710)	$0	$45,954	$127,212
2	**Total Residential**		$7,235	$15,684	$1,158	$1,794	$27,144	$39,240	$3,530	$44,217	$1,910	$868	$3,299	$984	$6,598	$695	($17,710)	$0	$45,954	$127,212
	Commercial & Industrial																			
3	Gen. Svc. < 31 kW	23	$1,511	$3,533	$232	$0	$6,113	$8,832	$535	$9,948	$395	$163	$628	$186	$1,255	$139	($2,812)	($4,184)	$10,366	$23,173
4	Gen. Svc. 31 - 200 kW	28	$1,879	$2,395	$413	$0	$4,171	$6,380	$227	$8,094	$516	$289	$1,094	$330	$2,230	$227	$13,751	$6,690	$25,644	$30,764
5	Gen. Svc. 201 - 999 kW	30	$1,078	$1,038	$266	$0	$1,796	$2,807	$80	$3,698	$306	$186	$692	$200	$1,411	$146	$8,620	$4,310	$14,740	$16,217
6	Large General Service >= 1,000 kW	48	$3,227	$2,292	$935	$1,123	$3,976	$6,267	$234	$8,325	$935	$608	$2,339	$655	$4,636	$514	$1,029	$0	$19,276	$32,091
7	Partial Req. Svc. >= 1,000 kW	47	$30	$21	$9	$10	$37	$58	$2	$77	$9	$6	$22	$6	$43	$5	$10	$0	$179	$298
8	Dist. Only Lg Gen Svc >= 1,000 kW	848	$232	$164	$0	$81	$285	$450	$17	$597	$0	$0	$0	$0	$0	$0	$0	$0	$547	$1,540
9	Agricultural Pumping Service	41	$324	$754	$47	$0	$1,306	$1,976	$42	$2,450	$82	$33	$122	$35	$242	$26	($3,902)	($7,442)	($1,212)	($1,308)
10	**Total Commercial & Industrial**		$8,280	$10,197	$1,903	$1,213	$17,683	$26,770	$1,137	$33,190	$2,244	$1,285	$4,896	$1,412	$9,817	$1,058	$16,695	($626)	$69,540	$102,774
	Lighting																			
11	Outdoor Area Lighting Service	15	$4	$32	$0	$0	$55	$77	$0	$80	$1	$0	$1	$0	$4	$0	$222	$83	$315	$282
12	Street Lighting Service Comp. Owned	51	$15	$115	$2	$0	$199	$275	$0	$280	$3	$0	$3	$1	$12	$1	$894	$407	$1,229	$1,113
13	Street Lighting Service, Cust Owned	53	$17	$16	$2	$0	$28	$39	$0	$41	$1	$1	$3	$1	$4	$1	$237	$111	$293	$237
14	Recreational Field Lighting	54	$3	$3	$0	$0	$5	$8	$0	$8	$0	$0	$1	$0	$1	$0	$47	$25	$58	$49
15	**Total Public Street Lighting**		$39	$166	$4	$0	$287	$398	$0	$408	$6	$1	$8	$2	$20	$2	$1,400	$626	$1,896	$1,681
16	**Subtotal**		$15,554	$26,047	$3,064	$3,008	$45,114	$66,408	$4,667	$77,815	$4,160	$2,154	$8,203	$2,398	$16,435	$1,754	$385	$0	$117,389	$231,667
17	Employee Discount		($4)	($9)	($1)	($1)	($16)	($23)	($2)	($26)	($1)	($1)	($2)	($1)	($4)	($0)	$10	$0	($27)	($73)
18	**Total**		$15,550	$26,038	$3,063	$3,007	$45,099	$66,386	$4,665	$77,789	$4,158	$2,153	$8,201	$2,398	$16,431	$1,754	$395	$0	$117,362	$231,593

PACIFIC POWER
PRESENT AND PROPOSED RATES OF ADJUSTMENT SCHEDULES
FORECAST 12 MONTHS ENDED DECEMBER 31, 2025

Line No.	Description	Pre Sch No.	Def. Insur. 80 ¢/kWh	WMVM Adj 94 ¢/kWh	Prop Sls. Adj 96 ¢/kWh	Intv. Fndg Adj 97 ¢/kWh	WMP Def Adj 190 ¢/kWh	WMP Def Adj 190 ¢/kWh	Def Acct Adj 192 ¢/kWh	Cat Wildf Adj 193 ¢/kWh	Repl Mtr Def Adj 194 ¢/kWh	Deer Cr Def Adj 198 ¢/kWh	RAC Defer. 203 ¢/kWh	Sol. Inctv. 204 ¢/kWh	PCAM Sec 206 ¢/kWh	PCAM Pri 206 ¢/kWh	PCAM Trn 206 ¢/kWh	Comm. Sol 207 ¢/kWh	RMA 299 ¢/kWh	RMA 299 ¢/kWh
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)
			PRO				PRE	PRO		PRO									PRE	PRO
	Residential																			
1	Residential	4	0.125	0.271	0.020	0.031	0.469	0.678	0.061	0.764	0.033	0.015	0.057	0.017	0.114			0.012	(0.306)	0.000
	Commercial & Industrial																			
2	Gen. Svc. < 31 kW	23	0.130	0.304	0.020	0.000	0.526	0.760	0.046	0.856	0.034	0.014	0.054	0.016	0.108	0.098		0.012	(0.242)	(0.360)
3	Gen. Svc. 31 - 200 kW	28	0.091	0.116	0.020	0.000	0.202	0.309	0.011	0.392	0.025	0.014	0.053	0.016	0.108	0.107		0.011	0.666	0.324
4	Gen. Svc. 201 - 999 kW	30	0.081	0.078	0.020	0.000	0.135	0.211	0.006	0.278	0.023	0.014	0.052	0.015	0.106	0.107		0.011	0.648	0.324
5	Large General Service >= 1,000 kW	48	0.069	0.049	0.020	0.024	0.085	0.134	0.005	0.178	0.020	0.013	0.050	0.014	0.106	0.101	0.095	0.011	0.022	0.000
6	Partial Req. Svc. >= 1,000 kW	47	0.069	0.049	0.020	0.024	0.085	0.134	0.005	0.178	0.020	0.013	0.050	0.014	0.106	0.101	0.095	0.011	0.022	0.000
7	Dist. Only Lg Gen Svc >= 1,000 kW	848	0.069	0.049	0.000	0.024	0.085	0.134	0.005	0.178	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	0.138	0.321	0.020	0.000	0.556	0.841	0.018	1.043	0.035	0.014	0.052	0.015	0.103	0.101		0.011	(1.661)	(3.168)
	Lighting																			
9	Outdoor Area Lighting Service	15	0.194	1.496	0.020	0.000	2.589	3.612	0.000	3.749	0.036	0.006	0.039	0.012	0.172			0.009	10.425	3.900
10	Street Lighting Service HPS	51	0.194	1.453	0.020	0.000	2.515	3.481	0.000	3.540	0.044	0.006	0.040	0.012	0.146			0.009	11.320	5.150
11	Street Lighting Service	53	0.194	0.183	0.020	0.000	0.317	0.443	0.000	0.460	0.017	0.006	0.037	0.012	0.043			0.009	2.682	1.260
12	Recreational Field Lighting	54	0.194	0.228	0.020	0.000	0.395	0.553	0.000	0.578	0.023	0.006	0.038	0.012	0.043			0.009	3.435	1.840

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 4 + Cost-Based Supply Service
Residential Service - Single Family

kWh	Monthly Billing* Present Price	Monthly Billing* Proposed Price	Difference	Percent Difference
100	$25.41	$33.17	$7.76	30.54%
200	$38.63	$49.09	$10.46	27.08%
300	$51.84	$64.99	$13.15	25.37%
400	$65.06	$80.90	$15.84	24.35%
500	$78.27	$96.81	$18.54	23.69%
600	$91.48	$112.71	$21.23	23.21%
700	$104.70	$128.62	$23.92	22.85%
800	$117.91	$144.52	$26.61	22.57%
900	$131.13	$160.44	$29.31	22.35%
950	**$137.73**	**$168.39**	**$30.66**	**22.26%**
1,000	$144.34	$176.34	$32.00	22.17%
1,100	$157.55	$192.24	$34.69	22.02%
1,200	$170.77	$208.16	$37.39	21.89%
1,300	$183.98	$224.06	$40.08	21.78%
1,400	$197.20	$239.97	$42.77	21.69%
1,500	$210.41	$255.88	$45.47	21.61%
1,600	$223.62	$271.78	$48.16	21.54%
2,000	$276.48	$335.41	$58.93	21.31%
3,000	$417.38	$503.24	$85.86	20.57%
4,000	$558.28	$671.07	$112.79	20.20%
5,000	$699.19	$838.90	$139.71	19.98%

* Net rate including Schedules 91, 92, 98, 290 and 291.

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	$22.36	$26.07	$3.71	16.59%
200	$35.58	$41.98	$6.40	17.99%
300	$48.79	$57.88	$9.09	18.63%
400	$62.01	$73.80	$11.79	19.01%
500	$75.22	$89.70	$14.48	19.25%
600	$88.43	$105.60	$17.17	19.42%
700	$101.65	$121.52	$19.87	19.55%
800	$114.86	$137.42	$22.56	19.64%
900	$128.08	$153.33	$25.25	19.71%
950	$134.69	$161.28	$26.59	19.74%
1,000	$141.29	$169.24	$27.95	19.78%
1,100	$154.50	$185.14	$30.64	19.83%
1,200	$167.72	$201.05	$33.33	19.87%
1,300	$180.93	$216.95	$36.02	19.91%
1,400	$194.15	$232.87	$38.72	19.94%
1,500	$207.36	$248.77	$41.41	19.97%
1,600	$220.57	$264.67	$44.10	19.99%
2,000	$273.43	$328.31	$54.88	20.07%
3,000	$414.34	$496.14	$81.80	19.74%
4,000	$555.24	$663.97	$108.73	19.58%
5,000	$696.14	$831.80	$135.66	19.49%

* Net rate including Schedules 91, 92, 98, 290 and 291.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 23 + Cost-Based Supply Service
General Service - Secondary 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	$87	$95	$105	$116	21.24%	21.75%
	750	$121	$130	$146	$157	20.79%	21.19%
	1,000	$156	$164	$188	$199	20.54%	20.88%
	1,500	$225	$234	$270	$281	20.27%	20.52%
10	1,000	$156	$164	$188	$199	20.54%	20.88%
	2,000	$294	$303	$353	$364	20.13%	20.32%
	3,000	$432	$441	$518	$529	19.98%	20.12%
	4,000	$552	$561	$666	$677	20.66%	20.76%
20	4,000	$588	$596	$711	$722	21.06%	21.15%
	6,000	$827	$836	$1,006	$1,017	21.66%	21.71%
	8,000	$1,067	$1,075	$1,301	$1,312	21.98%	22.02%
	10,000	$1,306	$1,315	$1,596	$1,607	22.19%	22.22%
30	9,000	$1,258	$1,267	$1,540	$1,551	22.39%	22.42%
	12,000	$1,617	$1,626	$1,982	$1,993	22.55%	22.57%
	15,000	$1,976	$1,985	$2,424	$2,435	22.65%	22.67%
	18,000	$2,336	$2,344	$2,866	$2,877	22.72%	22.74%

* Net rate including Schedules 91, 92, 290 and 291.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 23 + Cost-Based Supply Service
General Service - Primary 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	$85	$94	$104	$115	21.45%	21.95%
	750	$119	$128	$144	$155	21.02%	21.42%
	1,000	$153	$162	$185	$196	20.77%	21.10%
	1,500	$221	$230	$266	$277	20.51%	20.75%
10	1,000	$153	$162	$185	$196	20.77%	21.10%
	2,000	$289	$297	$347	$359	20.37%	20.56%
	3,000	$424	$433	$510	$521	20.22%	20.36%
	4,000	$542	$550	$655	$666	20.91%	21.00%
20	4,000	$577	$586	$700	$711	21.29%	21.38%
	6,000	$812	$821	$990	$1,001	21.90%	21.95%
	8,000	$1,048	$1,056	$1,280	$1,291	22.23%	22.27%
	10,000	$1,283	$1,291	$1,571	$1,582	22.44%	22.47%
30	9,000	$1,236	$1,245	$1,516	$1,527	22.62%	22.65%
	12,000	$1,589	$1,598	$1,951	$1,962	22.79%	22.81%
	15,000	$1,942	$1,950	$2,386	$2,397	22.90%	22.91%
	18,000	$2,294	$2,303	$2,821	$2,832	22.97%	22.98%

* Net rate including Schedules 91, 92, 290 and 291.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 28 + Cost-Based Supply Service
Large General Service - Secondary Delivery Voltage

kW Load Size	kWh	Monthly Billing* Present Price	Monthly Billing* Proposed Price	Percent Difference
15	3,000	$400	$446	11.41%
	4,500	$537	$590	9.98%
	7,500	$810	$879	8.56%
31	6,200	$808	$895	10.75%
	9,300	$1,090	$1,193	9.46%
	15,500	$1,654	$1,790	8.20%
40	8,000	$1,037	$1,147	10.61%
	12,000	$1,401	$1,532	9.35%
	20,000	$2,129	$2,302	8.12%
60	12,000	$1,547	$1,709	10.43%
	18,000	$2,093	$2,286	9.22%
	30,000	$3,186	$3,442	8.03%
80	16,000	$2,051	$2,262	10.28%
	24,000	$2,780	$3,033	9.10%
	40,000	$4,236	$4,573	7.95%
100	20,000	$2,556	$2,816	10.18%
	30,000	$3,466	$3,779	9.02%
	50,000	$5,287	$5,705	7.90%
200	40,000	$5,053	$5,548	9.78%
	60,000	$6,874	$7,473	8.71%
	100,000	$10,516	$11,325	7.69%

* Net rate including Schedules 91, 92, 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	$498	$606	21.58%
	6,000	$627	$741	18.14%
	7,500	$756	$876	15.87%
31	9,300	$1,010	$1,214	20.18%
	12,400	$1,276	$1,493	16.97%
	15,500	$1,543	$1,772	14.88%
40	12,000	$1,298	$1,556	19.88%
	16,000	$1,642	$1,916	16.72%
	20,000	$1,985	$2,276	14.66%
60	18,000	$1,939	$2,318	19.51%
	24,000	$2,455	$2,858	16.43%
	30,000	$2,970	$3,398	14.41%
80	24,000	$2,575	$3,070	19.21%
	32,000	$3,262	$3,790	16.18%
	40,000	$3,949	$4,510	14.20%
100	30,000	$3,211	$3,822	19.03%
	40,000	$4,070	$4,722	16.03%
	50,000	$4,929	$5,622	14.08%
200	60,000	$6,371	$7,541	18.37%
	80,000	$8,088	$9,341	15.49%
	100,000	$9,805	$11,141	13.62%

* Net rate including Schedules 91, 92, 290 and 291.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 30 + Cost-Based Supply Service
Large General Service - Secondary Delivery Voltage

kW Load Size	kWh	Monthly Billing* Present Price	Monthly Billing* Proposed Price	Percent Difference
100	20,000	$3,004	$3,524	17.30%
	30,000	$3,677	$4,230	15.05%
	50,000	$5,022	$5,642	12.35%
200	40,000	$5,565	$6,333	13.79%
	60,000	$6,911	$7,745	12.07%
	100,000	$9,601	$10,570	10.09%
300	60,000	$8,284	$9,395	13.42%
	90,000	$10,302	$11,514	11.76%
	150,000	$14,338	$15,751	9.85%
400	80,000	$10,889	$12,272	12.71%
	120,000	$13,580	$15,097	11.17%
	200,000	$18,961	$20,746	9.42%
500	100,000	$13,526	$15,203	12.40%
	150,000	$16,890	$18,734	10.92%
	250,000	$23,617	$25,796	9.23%
600	120,000	$16,164	$18,134	12.19%
	180,000	$20,200	$22,371	10.75%
	300,000	$28,272	$30,845	9.10%
800	160,000	$21,439	$23,995	11.93%
	240,000	$26,820	$29,645	10.53%
	400,000	$37,583	$40,944	8.94%
1000	200,000	$26,714	$29,857	11.77%
	300,000	$33,440	$36,919	10.40%
	500,000	$46,894	$51,042	8.85%

* Net rate including Schedules 91, 92, 290 and 291.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 30 + Cost-Based Supply Service
Large General Service - Primary Delivery Voltage

kW Load Size	kWh	Monthly Billing* Present Price	Monthly Billing* Proposed Price	Percent Difference
100	30,000	$3,630	$4,079	12.38%
	40,000	$4,298	$4,778	11.16%
	50,000	$4,967	$5,477	10.27%
200	60,000	$6,845	$7,507	9.67%
	80,000	$8,181	$8,904	8.84%
	100,000	$9,518	$10,302	8.23%
300	90,000	$10,202	$11,158	9.37%
	120,000	$12,207	$13,254	8.58%
	150,000	$14,212	$15,350	8.01%
400	120,000	$13,486	$14,692	8.95%
	160,000	$16,159	$17,487	8.22%
	200,000	$18,832	$20,282	7.70%
500	150,000	$16,771	$18,232	8.71%
	200,000	$20,113	$21,725	8.01%
	250,000	$23,455	$25,218	7.52%
600	180,000	$20,057	$21,771	8.54%
	240,000	$24,067	$25,963	7.88%
	300,000	$28,077	$30,155	7.40%
800	240,000	$26,629	$28,850	8.34%
	320,000	$31,976	$34,439	7.70%
	400,000	$37,322	$40,028	7.25%
1000	300,000	$33,201	$35,928	8.21%
	400,000	$39,884	$42,915	7.60%
	500,000	$46,567	$49,902	7.16%

* Net rate including Schedules 91, 92, 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	Monthly Bill	Annual Load Size Charge
Single Phase							
10	2,000	$233	$174	$280	$246	19.93%	41.52%
	3,000	$350	$174	$420	$246	19.93%	41.52%
	5,000	$583	$174	$699	$246	19.93%	41.52%
Three Phase							
20	4,000	$466	$347	$559	$491	19.93%	41.52%
	6,000	$700	$347	$839	$491	19.93%	41.52%
	10,000	$1,166	$347	$1,399	$491	19.93%	41.52%
100	20,000	$2,332	$1,604	$2,797	$2,274	19.93%	41.77%
	30,000	$3,499	$1,604	$4,196	$2,274	19.93%	41.77%
	50,000	$5,831	$1,604	$6,993	$2,274	19.93%	41.77%
300	60,000	$6,997	$3,979	$8,392	$5,643	19.93%	41.84%
	90,000	$10,496	$3,979	$12,588	$5,643	19.93%	41.84%
	150,000	$17,493	$3,979	$20,979	$5,643	19.93%	41.84%

* Net rate including Schedules 91, 92, 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	Monthly Bill	Annual Load Size Charge
Single Phase							
10	3,000	$344	$172	$413	$243	20.01%	41.42%
	4,000	$459	$172	$551	$243	20.01%	41.42%
	5,000	$573	$172	$688	$243	20.01%	41.42%
Three Phase							
20	6,000	$688	$343	$826	$485	20.01%	41.42%
	8,000	$917	$343	$1,101	$485	20.01%	41.42%
	10,000	$1,147	$343	$1,376	$485	20.01%	41.42%
100	30,000	$3,440	$1,573	$4,129	$2,243	20.01%	42.58%
	40,000	$4,587	$1,573	$5,505	$2,243	20.01%	42.58%
	50,000	$5,734	$1,573	$6,881	$2,243	20.01%	42.58%
300	90,000	$10,321	$3,908	$12,387	$5,572	20.01%	42.60%
	120,000	$13,762	$3,908	$16,515	$5,572	20.01%	42.60%
	150,000	$17,202	$3,908	$20,644	$5,572	20.01%	42.60%

* Net rate including Schedules 91, 92, 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 Present Price	Monthly Billing Proposed Price	Percent Difference
1,000	300,000	$32,764	$36,565	11.60%
	500,000	$47,055	$51,536	9.52%
	700,000	$61,346	$66,508	8.41%
2,000	600,000	$64,939	$72,298	11.33%
	1,000,000	$91,729	$100,637	9.71%
	1,400,000	$119,203	$129,500	8.64%
6,000	1,800,000	$180,421	$204,159	13.16%
	3,000,000	$262,842	$290,748	10.62%
	4,200,000	$345,263	$377,338	9.29%
12,000	3,600,000	$358,683	$405,474	13.05%
	6,000,000	$523,145	$578,273	10.54%
	8,400,000	$687,075	$750,541	9.24%

Notes:

On-Peak kWh	38.20%
Off-Peak kWh	61.80%

* Net rate including Schedules 91, 92, 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	$31,058	$37,466	20.63%
	500,000	$45,050	$52,125	15.70%
	700,000	$59,043	$66,783	13.11%
2,000	600,000	$61,537	$73,756	19.86%
	1,000,000	$87,643	$101,487	15.80%
	1,400,000	$114,507	$129,711	13.28%
6,000	1,800,000	$176,526	$213,510	20.95%
	3,000,000	$257,117	$298,183	15.97%
	4,200,000	$337,708	$382,856	13.37%
12,000	3,600,000	$350,923	$423,212	20.60%
	6,000,000	$511,725	$592,178	15.72%
	8,400,000	$671,996	$760,612	13.19%

Notes:

On-Peak kWh	37.89%
Off-Peak kWh	62.11%

* Net rate including Schedules 91, 92, 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	$42,973	$50,104	16.59%
	700,000	$56,452	$64,242	13.80%
2,000	1,000,000	$83,253	$96,724	16.18%
	1,400,000	$109,067	$123,886	13.59%
6,000	3,000,000	$247,194	$287,140	16.16%
	4,200,000	$324,634	$368,624	13.55%
12,000	6,000,000	$491,621	$568,682	15.67%
	8,400,000	$645,588	$730,738	13.19%

Notes:

On-Peak kWh	37.47%
Off-Peak kWh	62.53%

* Net rate including Schedules 91, 92, 290 and 291. Restricted Sch 291 applied to levels over 730,000 kWh.

Docket No. UE 433
Exhibit PAC/1911
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Residential Basic Charge Calculation

February 2024

Residential Basic Charge Calculation
20 Year Residential Marginal Unit Costs
12 Months Ended December 2025

	All Residential	Single Family	Multi-Family
Poles	$94.23	$106.31	$38.64
Conductor	$40.96	$46.20	$16.79
Transformers	$122.51	$156.22	$45.20
Service Drop	$84.10	$84.10	$84.10
Meters	$24.91	$24.91	$24.91
Meter Reading	$0.00	$0.00	$0.00
Billing & Collections	$25.10	$25.10	$25.10
Uncollectables	$11.60	$11.60	$11.60
Customer Service / Other	$10.69	$10.69	$10.69
Total per Year	$414.10	$465.14	$257.04
Total per Month	$34.51	**$38.76**	**$21.42**
Current Basic Charge		$11.00	$8.00
Proposed Basic Charge		**$16.00**	**$9.00**

Docket No. UE 433
Exhibit PAC/1912
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Residential Three-Phase Basic Charge Calculation

February 2024

PacifiCorp
State of Oregon
Calculation of Three-Phase Basic Charge Differential

Line No.	Description	Value	Source
1	Cost of 30 kVA Three-Phase Polemount Transformer	$8,519	Estimated cost of installation
2	Cost of 25 kVA Single-Phase Polemount Transformer	$4,653	Estimated cost of installation
3	Incremental Transformer Cost	$3,866	Line 1 - Line 2
4	Operations & Maintenance Cost	2.88%	PacifiCorp 2023 Use of Facilities Report
5	Incremental Operations & Maintenance Cost	$111.34	Line 3 * Line 4
6	Monthly Incremental Operations & Maintenance Cost	$9.28	Line 5 / 12
7	Proposed Monthly Three-Phase Charge	$9.00	Line 6 rounded to nearest whole number

Docket No. UE 433
Exhibit PAC/1913
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Customer-Funded Substation Credit

February 2024

PacifiCorp
State of Oregon
Calculation of Customer-Funded Substation Credit

Line No.	Description	Value	Source
1	Marginal Dist. Substation Costs - Schedule 48 Primary (> 4 MW Category)	$4,772,588	Exhibit PAC/1908 - Oregon Marginal Cost of Service Study, 'MarginalCosts' tab
2	Marginal Dist. Poles Costs - Schedule 48 Primary (> 4 MW Category)	$0	Exhibit PAC/1908 - Oregon Marginal Cost of Service Study, 'MarginalCosts' tab
3	Marginal Dist. Conductor Costs - Schedule 48 Primary (> 4 MW Category)	$0	Exhibit PAC/1908 - Oregon Marginal Cost of Service Study, 'MarginalCosts' tab
4	Marginal Customer - Metering Costs - Schedule 48 Primary (> 4 MW Category)	$42,584	Exhibit PAC/1908 - Oregon Marginal Cost of Service Study, 'MarginalCosts' tab
5	Marginal Customer - Billing Costs - Schedule 48 Primary (> 4 MW Category)	$6,880	Exhibit PAC/1908 - Oregon Marginal Cost of Service Study, 'MarginalCosts' tab
6	Marginal Customer - Uncollectible Costs - Schedule 48 Primary (> 4 MW Category)	$33,638	Exhibit PAC/1908 - Oregon Marginal Cost of Service Study, 'MarginalCosts' tab
7	Marginal Customer - Other Costs - Schedule 48 Primary (> 4 MW Category)	$1,774	Exhibit PAC/1908 - Oregon Marginal Cost of Service Study, 'MarginalCosts' tab
8	Total Marginal Distribution Costs - Schedule 48 Primary (> 4 MW Category)	$4,857,463	Line 1 + Line 2 + Line 3 + Line 4 + Line 5 + Line 6 + Line 7
9	Annualized Distribution O & M Loading Factor	44.0%	Exhibit PAC/1908 - Oregon Marginal Cost of Service Study, 'DistOM' tab
10	Marginal Dist. Substation Costs Less O&M - Schedule 48 Primary (> 4 MW Category)	$3,314,067	Line 1 / (1 + Line 9)
11	Proportion of Marginal Cost for Return on/Return of Dist. Substation to Total Marginal Distribution Cost - Schedule 48 Primary (> 4 MW Category)	68.2%	Line 10 / Line 8
12	Schedule 48 Primary (> 4 MW Category) Distribution Costs in Rates	$25,700,980	Exhibit PAC/1909 - Target Functionalized Revenues, Billing Determinants and Proposed Rates
13	Proportion of Unbundled Distribution Rates that are Non-FERC Transmission for Schedule 48 Primary	71.5%	Exhibit PAC/1908 - Oregon Marginal Cost of Service Study
14	Customer-Funded Substation Credit	$4,994,278	Line 11 * Line 12 * (1 - Line 13)
15	Schedule 48 Primary (> 4 MW Category) Load Size kW	3,334,729	Exhibit PAC/1909 - Target Functionalized Revenues, Billing Determinants and Proposed Rates
16	Customer-Funded Substation Credit Price($/Load Size kW-month)	**$1.50**	Line 14 / Line 15

Docket No. UE 433
Exhibit PAC/1914
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Residential Schedule 6 Time-of-Use Pilot Program Evaluation

February 2024

Rocky Mountain Power | Pacific Power

STATE OF OREGON RESIDENTIAL TIME-OF USE PILOT

Program Evaluation

February 2024

I. Introduction

In PacifiCorp's general rate case filed in 2020, Docket No. UE 374, the Commission approved Schedule 6, a new simplified residential time-of-use option. The ultimate design of Schedule 6 was the result of stakeholder input that was incorporated into the partial stipulation related to rate spread and rate design issues in the rate case.[1] Residential Time-of-Use Schedule 6 provides customers with pricing that is about 14¢ per kWh higher from 5p.m. to 9p.m. every evening and about 4¢ per kWh lower than standard rates during all other times. Table 1 below shows how the current prices as of January 10, 2024, compare between residential time-of-use Schedule 6 and standard residential Schedule 4:

Table 1. Comparison of Energy Prices on Schedule 6 (Time-of-Use) and Schedule 4 (Standard Residential)

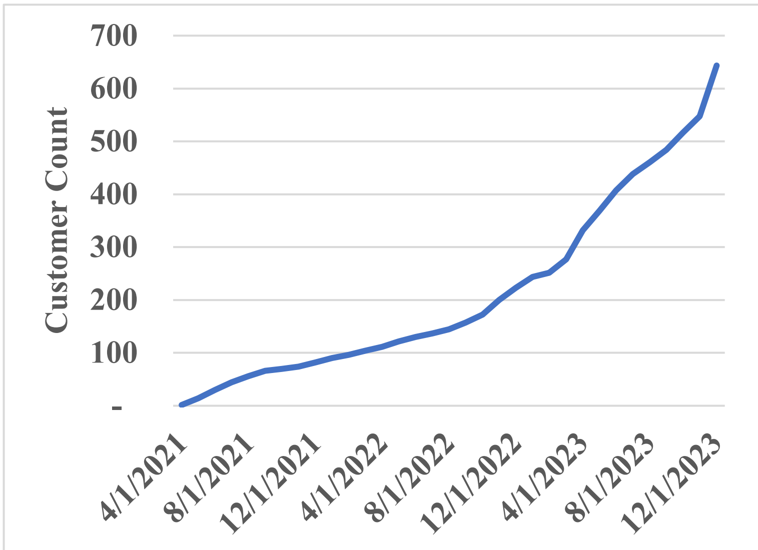
Time-of-Use Period	Time-of-Use Price	Standard Price
On-Peak	27.98¢ per kWh	13.71¢ per kWh
Off-Peak	9.92¢ per kWh	13.71¢ per kWh

To encourage customers to enroll in the program and avoid the risk of paying significantly more as they transition to time-of-use, participants are offered a first-year annual guarantee payment. If over the course of their first year on the program, they pay more than 10 percent on the time-of-use program than they would under standard rates, that customer receives a payment to limit the difference to no more than 10 percent.

[1] Partial Stipulation Related to Rate Spread and Rate Design filed on August 17, 2020, in Docket No. UE 374.

The first customer enrolled in Schedule 6 in April 2021. Since that time, the program has seen significant adoption. Continuous adoption through the present indicates that customers had an interest in the program. Figure 1 shows adoption of the program over time.

Figure 1. Schedule 6 Adoption Over time



II. Participant Bill Impact

After each Schedule 6 time-of-use participant reached its one-year anniversary on the program, the Company sent the customer a letter letting them know how much money the program saved them or cost them. The letter also informed them if they were eligible for an annual guarantee payment because they paid more than 10 percent higher for their energy cost. Through October 2023, 204 time-of-use anniversary letters were sent out. Table 2 summarizes the average savings or cost of these participants.

Table 2. Schedule 6 Participant Average Savings or Cost Summary

	Count	Annual Average Savings/(Cost)	Monthly Average Savings/(Cost)	Energy Cost Savings/(Cost)
Customers with Annual Bill Savings	163	$189.95	$15.83	13.2%
Customers with Annual Bill Cost	41	($46.78)	($3.90)	-4.9%
Total Customers Over a Year on Program as of October 2023	204	$142.38	$11.86	9.6%

Most customers saved money. The average amount they saved was about $16 per month or 13.2 percent. For a minority of customers, the program ended up costing them more. The average amount more they paid was about $4 per month or 4.9 percent higher for their energy cost.

Only a handful of customers received an annual guarantee payment. Table 3 summarizes the annual guarantee payments for these customers.

Table 3. Schedule 6 Annual Guarantee Payment Summary

	Count	Average Payment	Total Payments
Guarantee Payments	5	$52.24	$261.22

Figure 2 shows the proportions of customers who saved money, paid more money, and paid more money and received an annual guarantee payment.

Figure 2. Proportion of Schedule 6 Participants who Saved, Paid More, or Required a Guarantee Payment

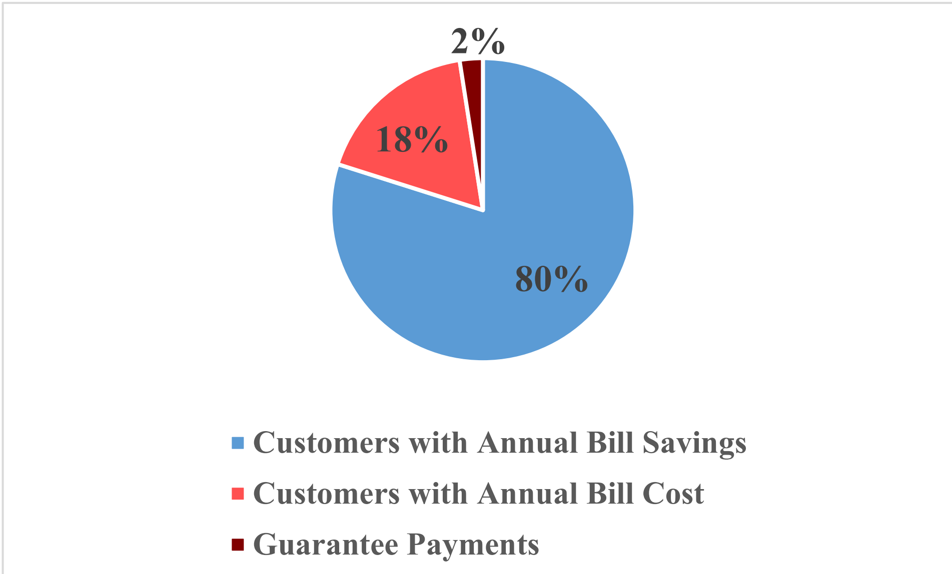


Figure 2 shows that about 80 percent of participants saved money and about 20 percent paid more under the program. Two percent paid more than 10 percent higher energy costs and required a guarantee payment.

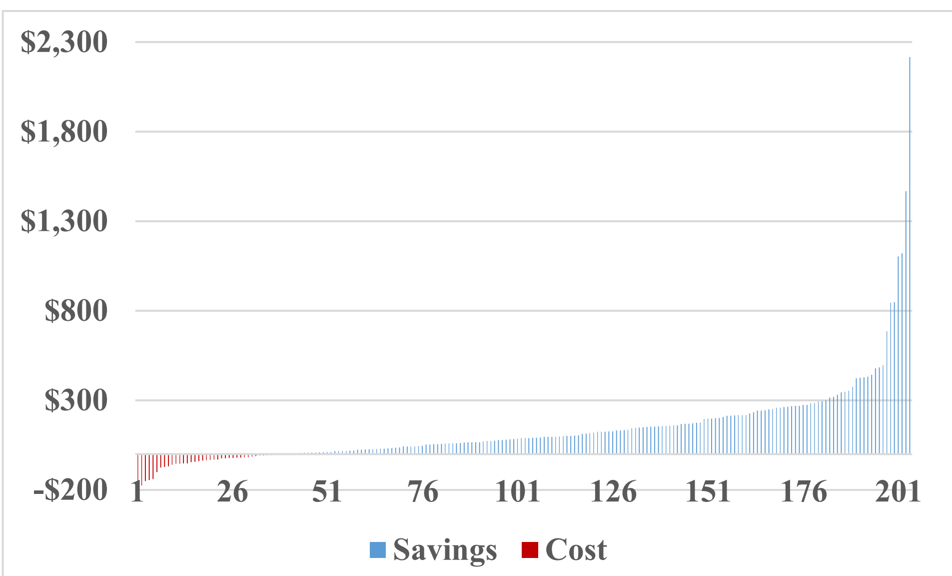
To better understand participants' bill experience, other statistics besides average were examined. Table 4 shows the median and maximum amounts that the program either saved or cost participants alongside averages.

Table 4. Average, Median, and Maximum Bill Impact for Program Participants

	Customers with Annual Bill Savings	Customers with Annual Bill Cost	Total Customers Over a Year on Program as of October 2023
Count	163	41	204
Annual Average Savings/(Cost)	$189.95	($46.78)	$142.38
Monthly Average Savings/(Cost)	$15.83	($3.90)	$11.86
Annual Median Savings/(Cost)	$125.20	($31.54)	$88.46
Monthly Median Savings/(Cost)	$10.43	($2.63)	$7.37
Maximum Annual Savings/(Cost)	$2,216.65	($189.47)	
Maximum Monthly Savings/(Cost)	$184.72	($15.79)	

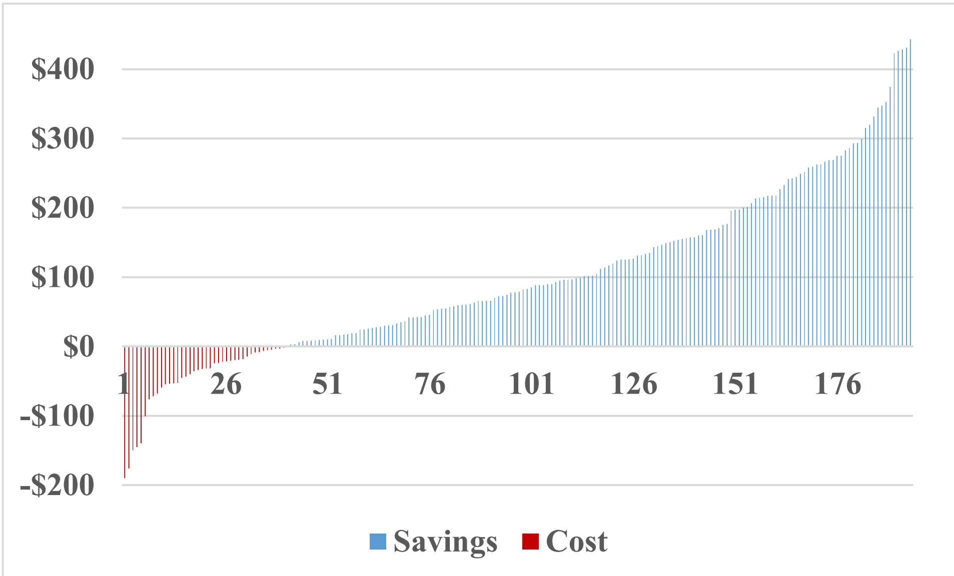
Figure 3 shows the individual bill impacts for the 204 time-of-use participants who finished one year on the program through October 2023 in ranked order.

Figure 3. Individual Participants' Annual Bill Impacts



There were a handful of very large energy users who had disproportionately high annual savings. To better show the bill impact for most participants, Figure 4 shows the same information as Figure 3, but with the top 5 percent of annual bill savings excluded.

Figure 4. Individual Participants' Annual Bill Impacts Excluding Highest 5 Percent

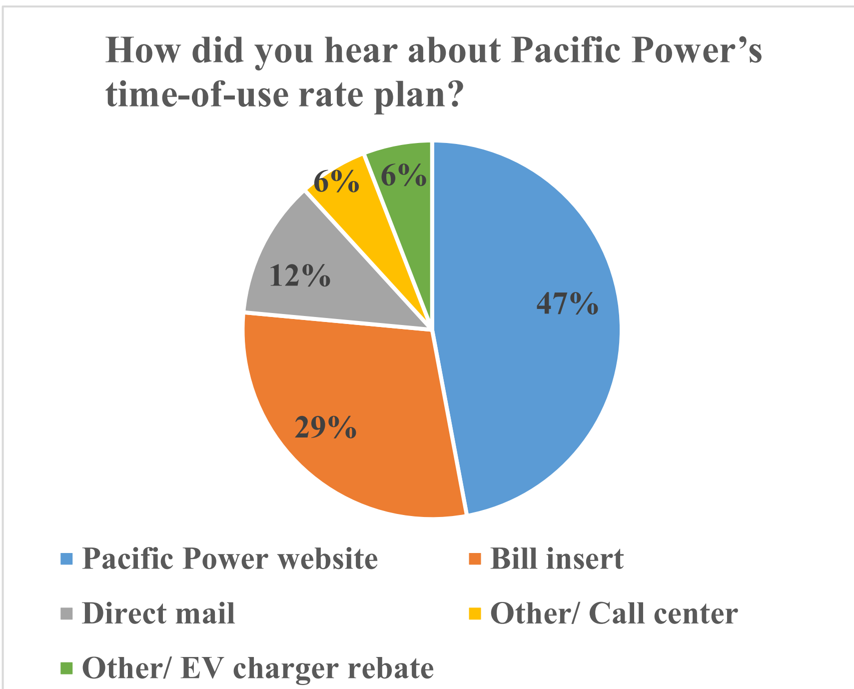


III. Survey Responses

In the 204 time-of-use anniversary letters that were sent out, an invitation to take a short online survey was included. 17 of the 204 participants completed this survey. The survey asked participants questions about how they learned about the program, what their satisfaction with the program is, their motivation for enrolling, their experience on the program, and some demographic questions about themselves.

Survey respondents were asked how they became aware of the program. Figure 5 shows the different ways that participants indicated they became aware of the program.

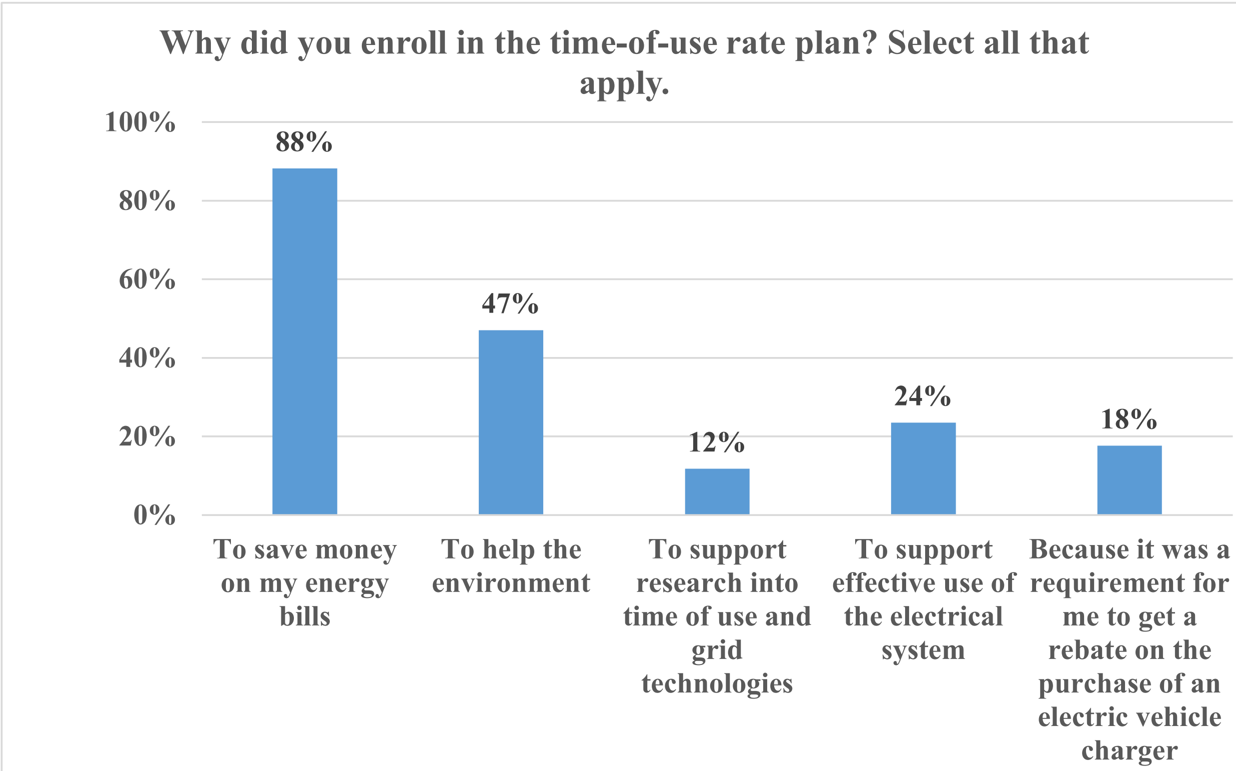
Figure 5. Program Awareness Method



The Company's website was the most prevalent way that survey respondents became aware of the program with nearly half of respondents indicating that this was how they heard about it. At about a third of responses, bill inserts were the second most prevalent way that respondents indicated they became aware of Schedule 6. Respondents also listed the direct mail, a call with one of the customer care agents, and the electric vehicle charger rebate as other ways that they learned about the program.

The survey asked respondents about why they enrolled in the program. Figure 6 shows the reasons respondents gave for enrolling.

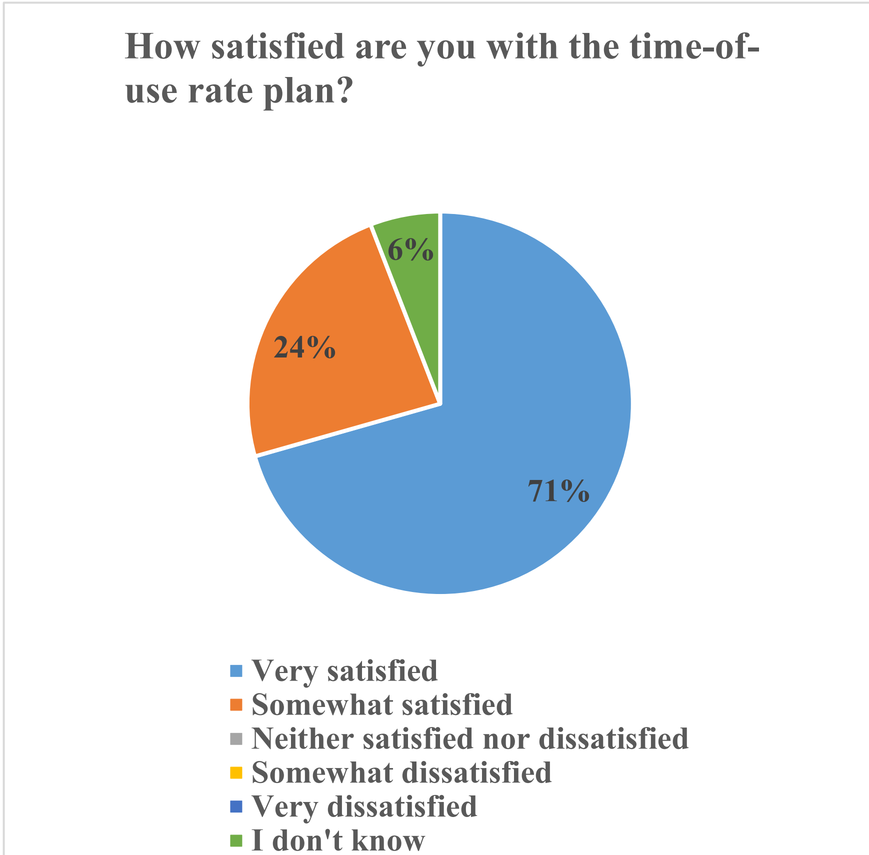
Figure 6. Program Enrollment Motivation



Almost all participants noted saving money as a reason for enrolling. A little less than half cited helping the environment. A small minority of respondents selected other reasons.

The survey asked respondents about their satisfaction with the program. Figure 7 shows their responses

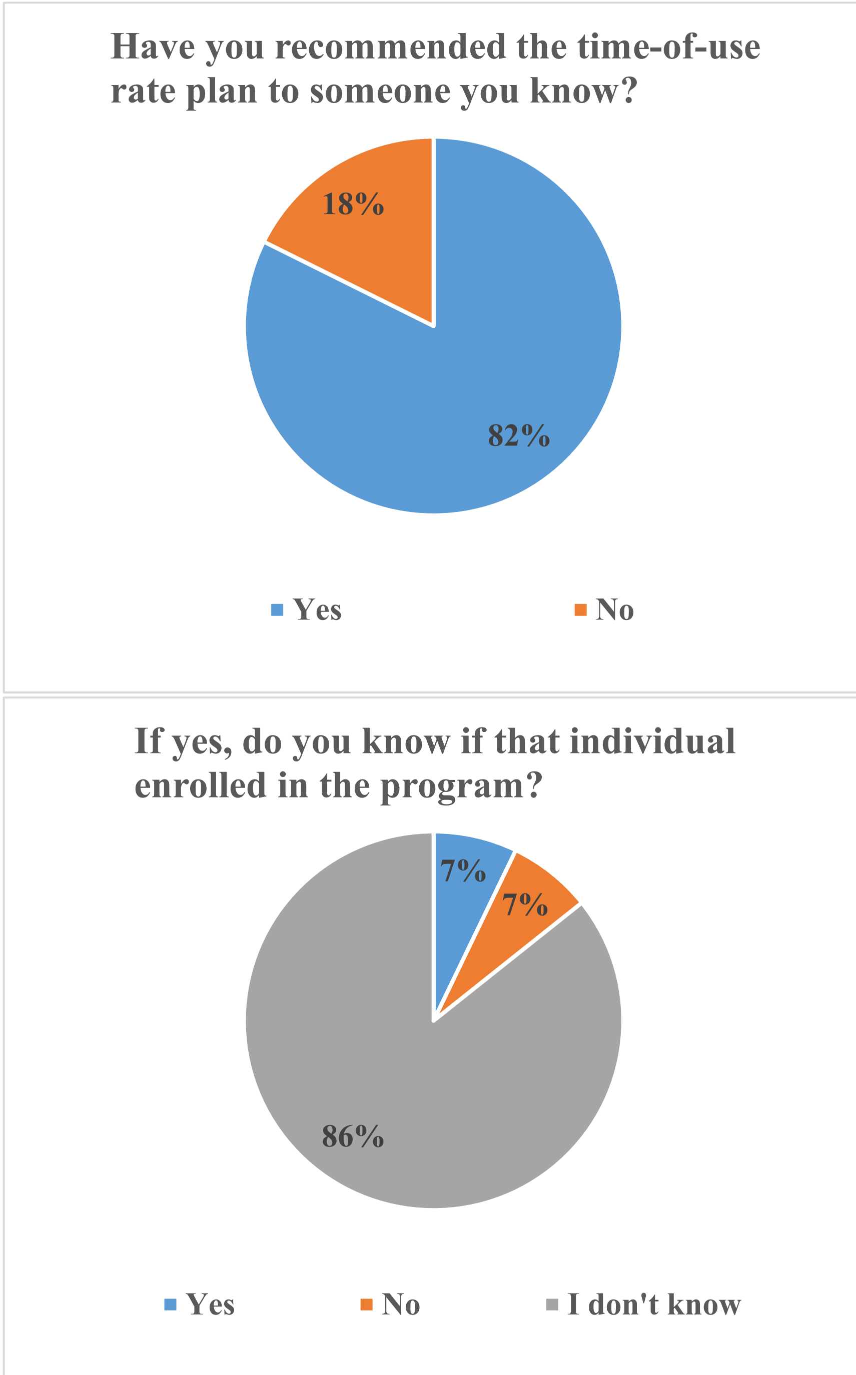
Figure 7. Program Satisfaction



Although the sample size of 17 is relatively small, responses indicated strong satisfaction with the program. Most survey respondents indicated they were very satisfied and about a quarter indicated they were somewhat satisfied. One customer responded with "I don't know".

The survey asked participants if they recommended the program to someone else. Figure 8 summarizes their responses.

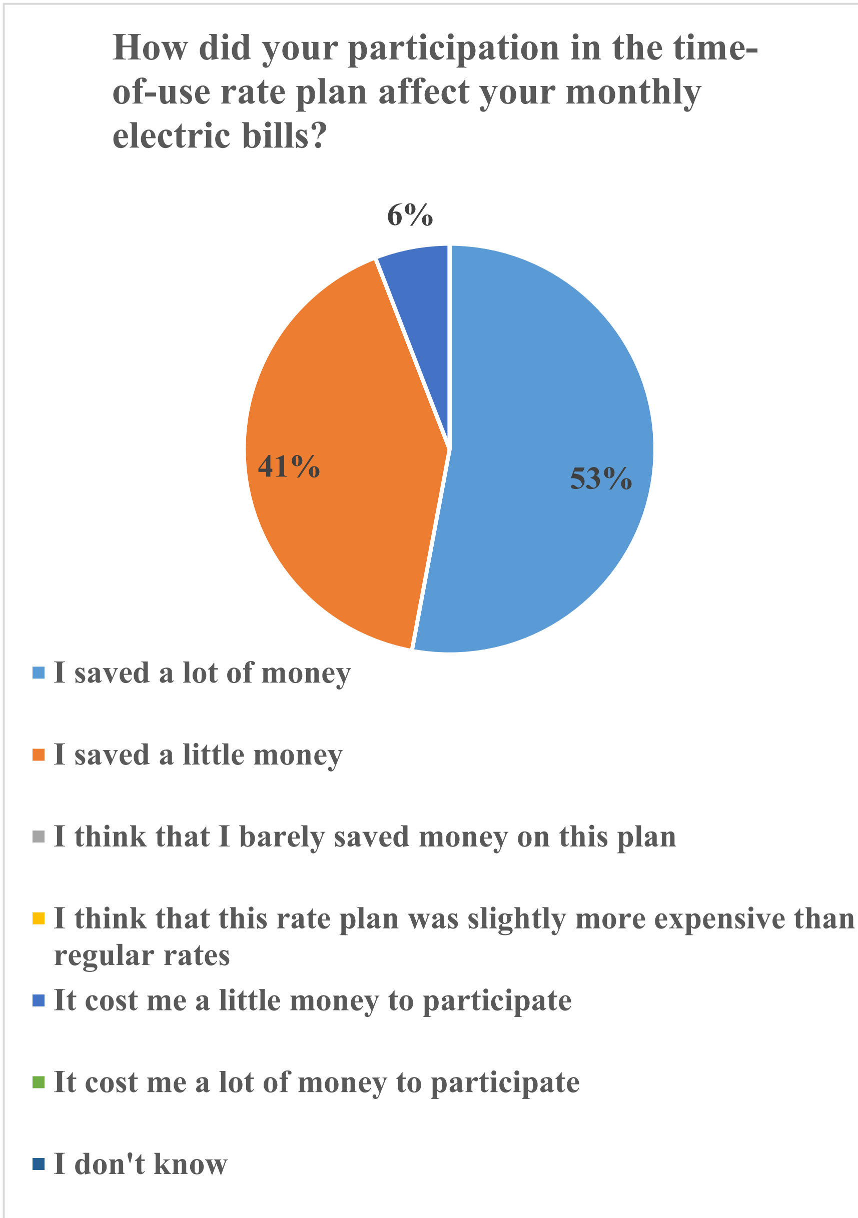
Figure 8. Program Referrals



Most (82 percent) survey respondents recommended the program to someone they knew. However, most (86 percent) who answered "Yes" were unaware whether the individual they referred ultimately enrolled in the program or not.

The survey asked participants about their perceptions of how much the program saved or cost them. Figure 9 shows the responses for this question.

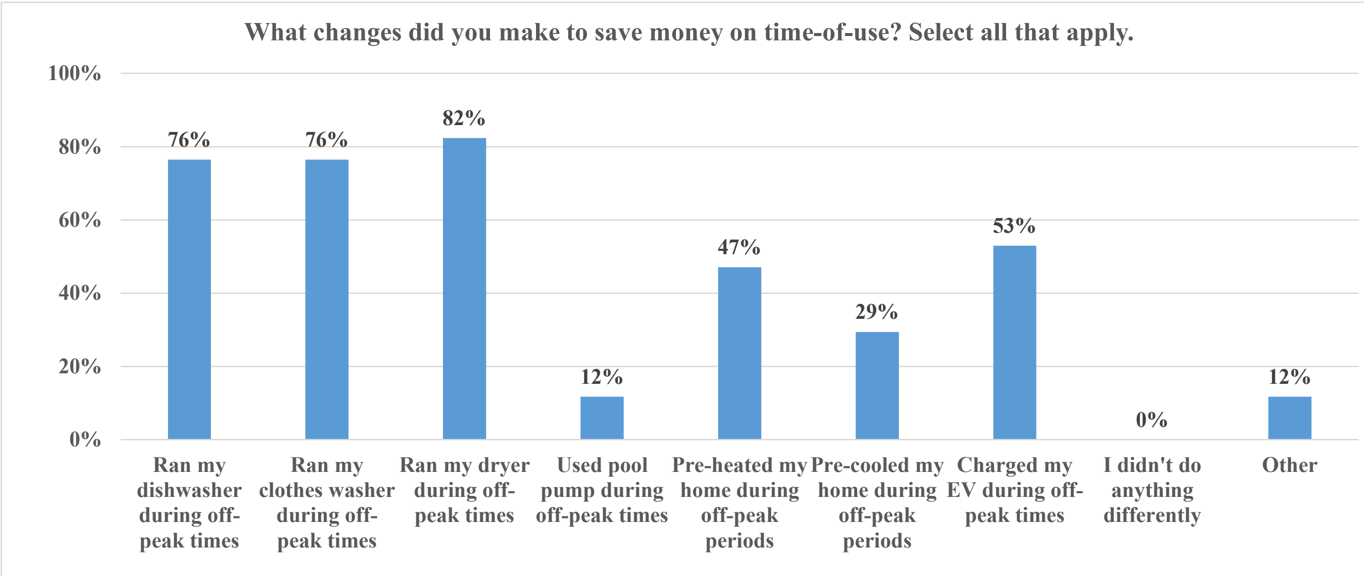
Figure 9. Bill Savings/Cost Perception



Almost all respondents indicated that they saved money. Only one respondent indicated losing money on the program.

Participants were asked what actions they took to save money on the program. Figure 10 shows their responses to this question.

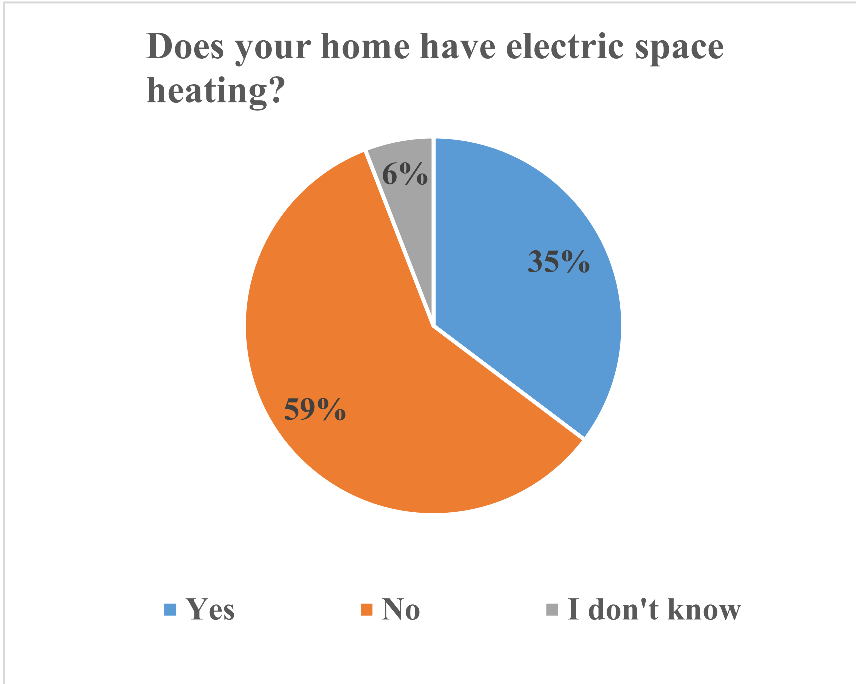
Figure 10. Actions Taken for Time-of-Use Program

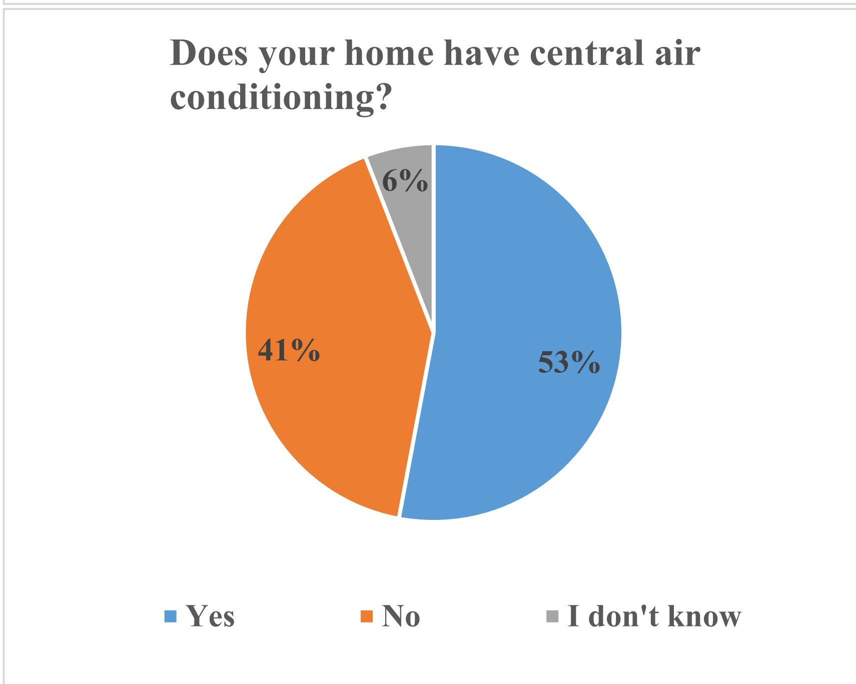


Most respondents indicated that they ran their dishwasher, clothes washer, and dryer during off-peak times. About half of respondents indicated that they pre-heated their homes or charged their electric vehicle during off-peak times. Notably, no respondent indicated that they did not do anything differently.

The survey asked participants about their heating and cooling equipment. Figure 11 shows their responses.

Figure 11. Heating and Cooling Equipment Respondents

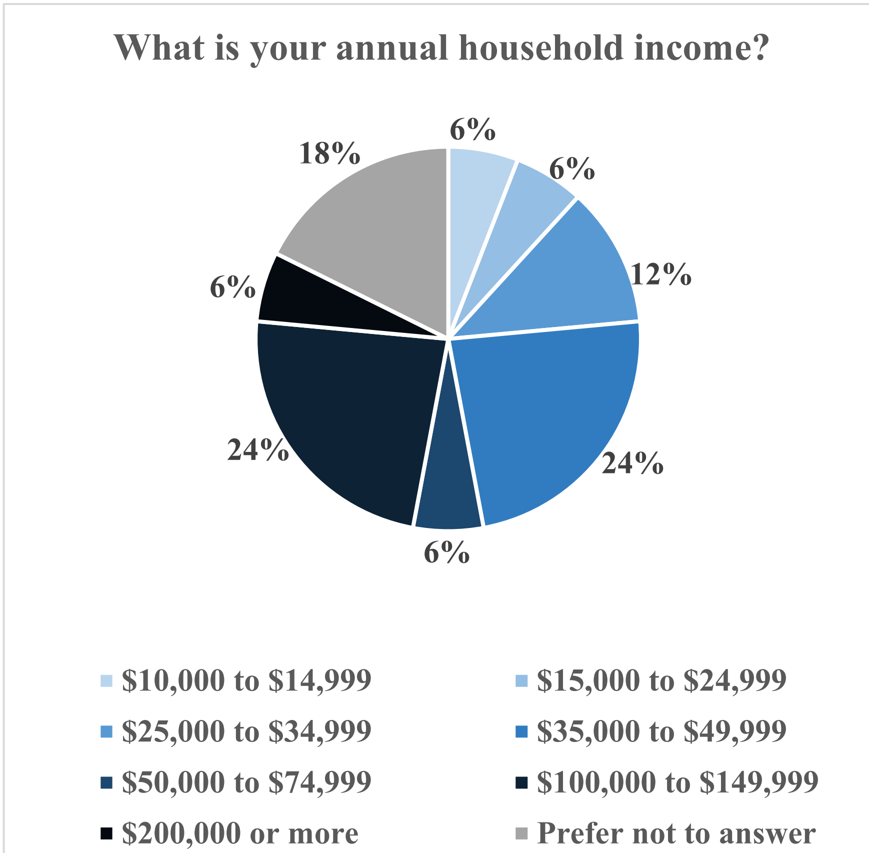


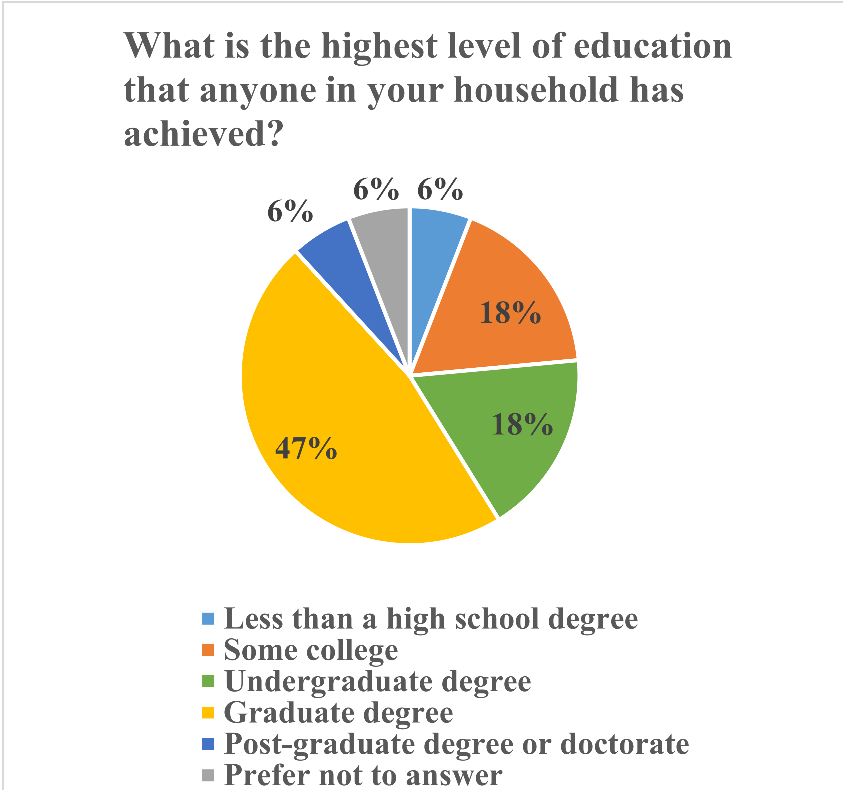


Only about a third of respondents indicated that they have electric space heating and about half indicated that they have central air conditioning.

Finally participants were asked demographic questions about their household income and the highest level of education attained in their household. Figure 12 shows their responses to these questions.

Figure 12. Demographic Information of Respondents





A fairly diverse range of incomes were indicated from survey responses with low-, moderate- and high-income all being represented. While differing levels of education were indicated from respondents, the sample of individuals who responded seemed to skew towards a higher level of educational attainment with nearly half indicating that someone in their household had a graduate degree.

IV. Usage Characteristics of Program Participants

On average, Schedule 6 time-of-use participants use more energy than standard residential Schedule 4 customers. Table 4 shows the comparison of average usage.

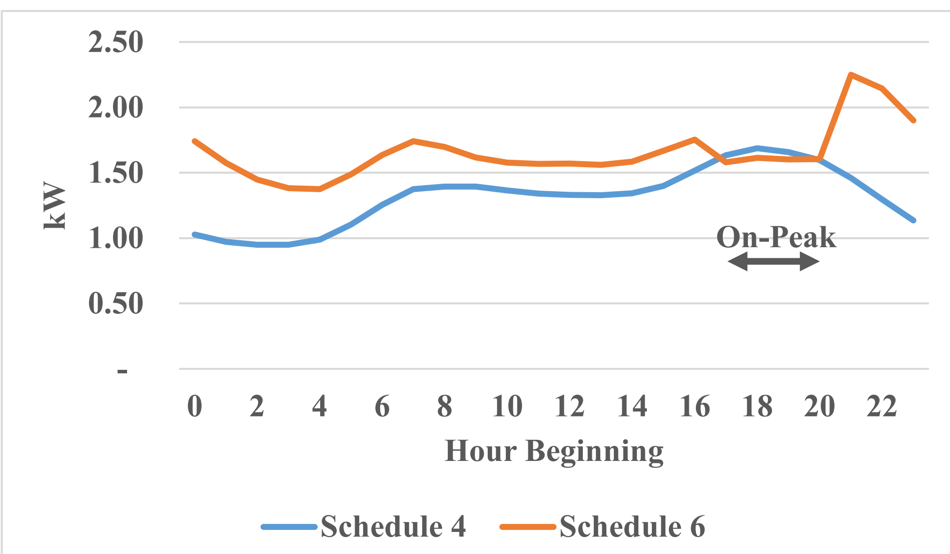
Table 4. Average Energy Usage of Schedule 6 Time-of-Use Participants Compared to Standard Schedule 4 Customers

	Schedule 4 Standard Residential	Schedule 6 Residential Time of Use	Difference	Difference (%)
kWh	958	1,207	248	25.9%

There are a number of reasons why participants may use more energy. A customer with a larger bill may be more motivated to enroll in a program like time-of-use. Also customers who have electric vehicles that they charge at home use more energy and may have greater opportunities to save by shifting the time-of charging and/or may be required to enroll in time-of-use as a condition of receiving a charger incentive.

The average hourly usage profile for Schedule 6 participants is higher than for customers on standard residential Schedule 4, but noticeably has a dip in usage during the on-peak period from 5p.m.-9p.m. Figure 13 shows the average hourly profile for Schedule 6 compared to Schedule 4.

Figure 13. Hourly Profile of Schedule 6 Time-of-Use Participants Compared to Standard Residential Schedule 4 Customers



To illustrate how the shape of Schedule 6 participants' hourly load profile compares to that of Schedule 4 customers, the hourly profile of Schedule 4 can be scaled up such that its overall usage level is the same as Schedule 6. Figure 14 shows the same information as Figure 13, but with the hourly profile of Schedule 4 scaled to the same energy level as Schedule 6.

Figure 14. Hourly Profile of Schedule 6 Time-of-Use Participants Compared to Scaled Up Standard Residential Schedule 4 Customers

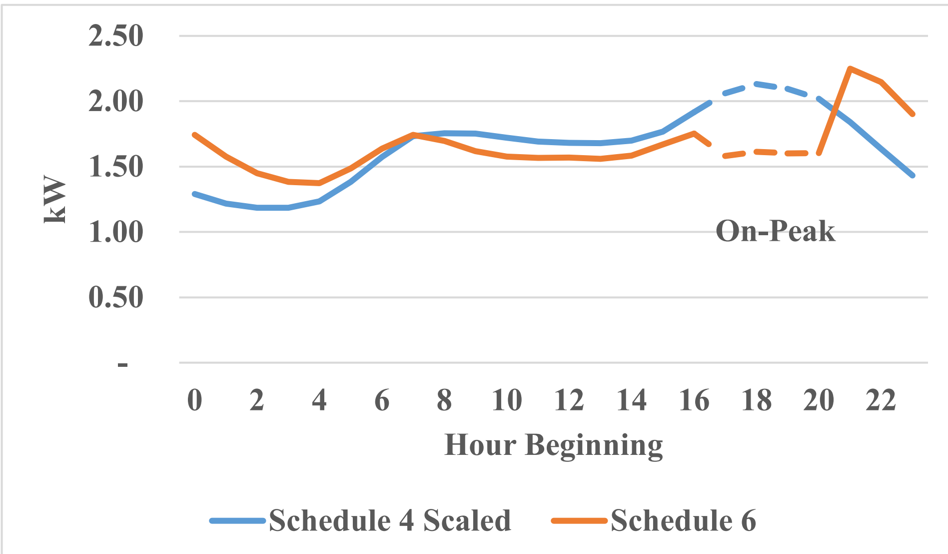


Figure 14 indicates that on average, Schedule 6 participants trim their load by about one half of a kilowatt during the on-peak period of 5p.m.-9p.m.. Usage after 9p.m. until 6am is a little higher.

V. Program Benefits

The potential benefits of the Schedule 6 time-of-use program include reduced energy costs from the shifted timing of usage, reduced generation capacity costs from lower demand during times that are significant from a capacity planning perspective, and reduced transmission cost by reducing the 12 coincident peak allocation of FERC transmission costs to PacifiCorp network customers. To examine these benefits the incremental profile of Schedule 6 time-of-use participants was compared to the profile of standard residential Schedule 4 scaled up to the same monthly usage level as Schedule 6 (net Schedule 6 profile).

The value of shifted energy was estimated by taking the net Schedule 6 profile and multiplying each hour by the average price from the Western Energy Imbalance Market (WEIM) by hour and month using the PAC-W, PAC-E, and Malin nodes for the 36 months ended June 2023. This value was then scaled by a factor of 1.61 to bring the value considered up from using historic WEIM prices to the marginal energy cost forecast for 2025 in the Company's most recently filed 2024 general rate case. Using this approach, the value of shifted energy was estimated to be an annual $26.93 per participant. Figure 15 summarizes this calculation by month and hour.

Figure 15 Estimated Value of Shifted Energy per Schedule 6 Time-of-Use Participant Using Average WEIM Prices for the 36 Months Ended June 2023 Period

	Hour Beginning																								
Month	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**Total**
7	0.6	0.4	0.3	0.3	0.2	0.2	0.1	0.0	(0.0)	(0.1)	(0.1)	(0.1)	(0.2)	(0.2)	(0.2)	(0.2)	(0.3)	(1.0)	(1.3)	(1.4)	(0.9)	0.4	0.6	0.6	(2.5)
8	0.7	0.5	0.4	0.4	0.3	0.2	0.1	0.0	(0.0)	(0.1)	(0.1)	(0.2)	(0.2)	(0.3)	(0.4)	(0.3)	(0.5)	(1.5)	(2.2)	(1.7)	(0.9)	0.7	0.8	0.7	(3.5)
9	0.6	0.5	0.4	0.3	0.2	0.2	0.1	0.0	(0.0)	(0.1)	(0.1)	(0.1)	(0.2)	(0.3)	(0.3)	(0.4)	(0.6)	(1.7)	(2.3)	(1.9)	(0.9)	0.8	0.8	0.7	(4.2)
10	0.6	0.5	0.3	0.3	0.2	0.2	0.1	(0.1)	(0.2)	(0.3)	(0.2)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.3)	(1.0)	(1.2)	(0.9)	(0.6)	0.6	0.8	0.6	(1.2)
11	0.6	0.4	0.2	0.1	0.0	0.1	0.1	(0.0)	(0.1)	(0.3)	(0.2)	(0.1)	(0.1)	(0.0)	(0.0)	(0.0)	(0.1)	(1.0)	(0.9)	(0.9)	(0.8)	0.7	0.9	0.7	(0.7)
12	1.1	0.7	0.4	0.2	0.1	0.1	0.1	(0.0)	(0.3)	(0.5)	(0.5)	(0.4)	(0.1)	(0.2)	(0.1)	(0.1)	(0.2)	(1.9)	(1.9)	(1.8)	(1.3)	1.8	1.9	1.4	(1.4)
1	0.7	0.6	0.3	0.3	0.1	0.1	0.1	0.0	(0.1)	(0.3)	(0.3)	(0.2)	(0.2)	(0.1)	(0.0)	0.2	(0.1)	(1.1)	(1.2)	(1.2)	(1.0)	0.8	1.0	0.8	(0.7)
2	0.5	0.4	0.2	0.1	0.0	0.0	(0.0)	0.1	(0.0)	(0.2)	(0.2)	(0.1)	(0.0)	(0.0)	0.0	0.0	(0.1)	(0.8)	(1.1)	(1.1)	(0.8)	0.7	0.8	0.6	(0.9)
3	0.6	0.3	0.2	0.1	(0.1)	(0.1)	(0.1)	0.0	(0.0)	(0.2)	(0.2)	(0.1)	(0.0)	(0.0)	(0.0)	0.0	(0.1)	(0.5)	(0.7)	(0.7)	(0.6)	0.6	0.7	0.6	(0.2)
4	0.7	0.5	0.4	0.3	0.3	0.3	0.4	0.0	(0.0)	(0.1)	(0.2)	(0.2)	(0.2)	(0.2)	(0.1)	(0.2)	(0.2)	(0.6)	(1.0)	(1.2)	(1.0)	0.8	0.7	0.6	(0.1)
5	0.4	0.4	0.3	0.2	0.2	0.2	0.1	0.0	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.2)	(0.2)	(0.2)	(0.2)	(0.5)	(0.7)	(0.7)	(0.6)	0.5	0.6	0.5	(0.4)
6	0.4	0.3	0.2	0.1	0.1	0.1	0.0	(0.0)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.2)	(0.2)	(0.2)	(0.3)	(0.6)	(0.5)	(0.5)	(0.4)	0.5	0.6	0.4	(0.9)
Total	7.4	5.5	3.7	2.7	1.8	1.6	1.1	0.1	(1.0)	(2.3)	(2.3)	(1.8)	(1.5)	(1.7)	(1.7)	(1.5)	(3.0)	(12.2)	(15.0)	(14.0)	(9.9)	8.8	10.2	8.1	

Estimated Value of Shifted Energy (Historic WEIM Pricing)

($16.69)

Average Historic WEIM Price

$51.42

1 Year Marginal Energy Cost (Uses Flat MidC Forecast)

$82.95

Scaling Factor

1.61

Estimated Value of Shifted Energy (Marginal Energy Cost)

($26.93)

Figure 15 shows that there were shifted energy benefits in every month, but they were strongest during the peak third quarter months of July, August, and September. The annual benefit of shifted load away from 5p.m.-9p.m. (displayed as hours beginning 17-20) was estimated to be about $82, but this amount is offset by higher load in the hours between 9p.m. and 7a.m.

Generation capacity benefit was estimated by comparing the net Schedule 6 profile against loss of load probability in 2024 from the preferred portfolio in PacifiCorp's 2021 Integrated Resource Plan. This calculation indicated that the reduction in load for each Schedule 6 participant contributed to about a 0.38 kW reduction to capacity need. In PacifiCorp's 2024 General Rate Case, its marginal cost of service study indicated that the marginal cost of generation capacity based upon the resource costs of a utility-scale 4-hour lithium ion battery is $156.28 per kW-year. Multiplying this cost by the 0.38 kW per participant estimate of capacity reduction yields an estimated benefit of $59.10. Table 5 shows this calculation.

Table 5. Calculation of Estimated Schedule 6 Generation Capacity Benefit

Marginal Generation Capacity Cost	$156.28
kW Avoided	(0.38)
Estimated Generation Capacity Benefit	**-$59.10**

PacifiCorp's FERC transmission costs are allocated to PacifiCorp and other transmission customers on the basis of PacifiCorp's 12 monthly system coincident peaks. Inasmuch as PacifiCorp's customers can reduce their loads during the 12 coincident peaks, those costs can be shifted onto other PacifiCorp transmission customers. On average, the net Schedule 6 profile is a 0.19 kW reduction, during the 12 coincident peaks hours for the 12 month period ended June 2023. Using the network service rate of $37,098 per MW-year from the 2023 Transmission Formula Rate Annual Update yields a $7.14 per participant benefit. Table 6 summarizes the calculation of this estimated benefit.

Table 6. Calculation of Estimated Schedule 6 Transmission Capacity Benefit

Month	Month	Day	Hour	Schedule 6 Net Profile (kW)
1/1/2023	1	30	8	(0.41)
2/1/2023	2	2	7	(0.01)
3/1/2023	3	6	7	0.12
4/1/2023	4	3	7	(0.13)
5/1/2023	5	19	15	(0.37)
6/1/2023	6	30	16	(0.41)
7/1/2022	7	27	15	(0.19)
8/1/2022	8	31	15	(0.05)
9/1/2022	9	6	15	(0.31)
10/1/2022	10	6	15	(0.18)
11/1/2022	11	29	17	(0.57)
12/1/2022	12	22	16	0.19
	12 Coincident Peak Reduction (kW)			(0.19)
	Network service rate ($/MW-year)			$37,098
	Avoided Transmission Cost Benefit			**-$7.14**

In total, the estimated quantifiable per participant benefit is $93.17. Table 7 summarizes the estimated benefits of the Schedule 6 program.

Table 7. Estimated Quantifiable Benefits of the Schedule 6 Program

Shifted Energy Value	-$26.93
Generation Capacity	-$59.10
Transmission Capacity	-$7.14
Total Per Participant Benefit	**-$93.17**

VI. Comparison to Legacy Time-of-Use Option

Schedule 6 was introduced as a pilot time-of-use option in 2021. However, legacy Schedule 210 time-of-use has been an option for the Company's Oregon customers since 2002. There are several key differences between pilot option Schedule 6 and legacy Schedule 210. Notably, Schedule 6 has a very simple time-of-use period of 5p.m.-9p.m. being on-peak and all other hours being off-peak. For Schedule 210, between the winter months of November through March, on-peak periods are Monday through Friday, excluding holidays, from 6am to 10am and again from 5p.m.-8p.m. Between the summer months of April through October, on-peak periods on Schedule 210 are Monday through Friday, excluding holidays, from 4p.m. to 8p.m. All other hours are considered off-peak.

Schedule 6 also has a more significant difference between on- and off-peak price compared to legacy Schedule 210. On Schedule 6, the on-peak price is 27.980¢ per kWh and the off-peak price is 9.920¢ per kWh—roughly a 2.8 to 1 differential. On Schedule 210, the on-peak price is 19.834¢ per kWh during summer months and 17.026¢ per kWh during winter months with the off-peak price being 12.585¢ per kWh—roughly a 1.6 to 1 differential in the summer and a 1.4 to 1 differential in the summer. As a result of the more tepid differential, Schedule 210 participants save on average $0.98 per month. This compares to the $11.86 per month average bill savings experienced by Schedule 6 participants discussed earlier in this report.

As shown on Figure 1 earlier in the report, adoption for Schedule 6 has been robust. Every month, new customers have steadily enrolled in the program. After being in existence about three years, the program now has over 600 participants. In contrast, legacy Schedule 210 adoption has stalled out with only about 900 participants after about 21 years. In recent years, enrollment in Schedule 210 has declined. Figure 16 shows enrollment for pilot Schedule 6 compared to legacy Schedule 210 from 2021 through 2023.

Figure 16. Comparison of Enrollment in Schedule 6 to Schedule 210 Over Time

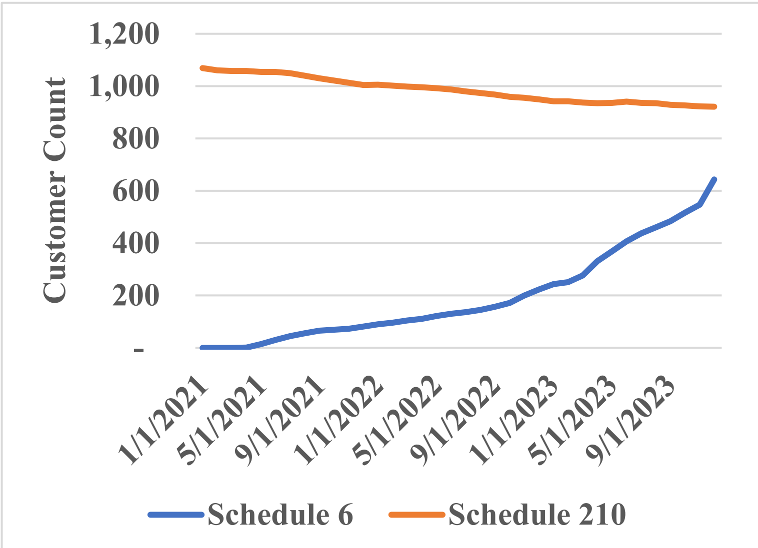


Table 8 provides a comparison of the pilot time-of-use Schedule 6 program to the legacy time-of-use Schedule 210 program.

Table 8. Comparison of Pilot Schedule 6 to Legacy Schedule 210

	Schedule 6	**Schedule 210**
Time of Use Periods	On-Peak - 5pm-9pm, all days Off-Peak - All other times	On-Peak - Nov-Mar - 6am-10am & 5pm-8pm, Mon-Fri, excluding holidays Apr-Oct - 4pm-8pm, Mon-Fri, excluding holidays Off-Peak - All other times
On- to Off-Peak Price Differential	2.8:1	Nov-Mar - 1.6:1 Apr-Oct - 1.4:1
Average Participant Bill Savings	$11.86 per month	$0.98 per month

VII. Conclusion/Recommendation

Schedule 6 has been a successful residential time-of-use program. Participants indicate a high level of satisfaction with the program, most participants save a meaningful amount of money each month, and system benefits have been demonstrated from shifted load. While the sample size of survey respondents is relatively small, the survey results indicate that customers from a wide range of incomes have participated in the program. It is recommended that the Schedule 6 program end its pilot phase and become an ongoing option for residential customers. While the system benefits of the program are less than the bill savings participants receive, participation is still relatively small. If a more significant level of participation is achieved in the future, Residential Time-of-Use Schedule 6 could be put on its own cost of service class to ensure subsidization is minimized. To reduce customer confusion, it is recommended that Schedule 210 be discontinued, since it is more difficult for customers to understand and provides minimal benefits for participants.

Docket No. UE 433
Exhibit PAC/1915
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Non-Residential Schedule 29 Time-of-Use Pilot Program Evaluation

February 2024

Rocky Mountain Power | Pacific Power

STATE OF OREGON SCHEDULE 29 - NON-RESIDENTIAL TIME OF USE PILOT

Program Evaluation

February 2024

I. Introduction

In PacifiCorp's general rate case filed in 2020, Docket No. UE 374, the Commission approved Schedule 29, a new time of use rate option pilot designed to help medium-sized non-residential customers who have very low load factors such as electric vehicle fast-charging equipment. Instead of charging traditional demand charges on a per kW basis, participants have energy charges that decline as their load factor increases with an added incentive to shift usage to off peak times through an off peak energy credit. Table 1 below shows how the current prices as of January 10, 2024 compare between optional Schedule 29 and standard non-residential Schedule 28 and Schedule 30:

Table 1. Comparison of Prices on Optional Schedule 29 and Schedule 28 and 30

Charge	Schedule 29 (Optional)	Schedule 28 (31-200 kW)	Schedule 30 (201-999 kW)
Energy Charge	**On Peak** - 28.324¢ per First Block kWh, 8.855¢ Additional kWh **Off Peak** - 27.585¢ per First Block kWh, 8.116¢ Additional kWh	8.786¢ per kWh	6.486¢ per kWh
Basic Charge	$36/Month	$18, $34, or $81 per Month (Depends on Load Size)	$126 or $334 per Month (Depends on Load Size)
Demand Charge	None	$6/kW	$11.98/kW
Load Size Charge	None	$1.15, $0.90, or $0.55 per kW (Depends on Load Size)	$1.55 or $0.75 per kW (Depends on Load Size)

Adoption for Schedule 29 has been slow. Only one customer has enrolled. This customer is a public DC fast charging station located in a remote location. The customer began taking service in May 2023 and has a very low load factor of about 0.5%. Because there is very little data on this pilot (one customer with a partial year of participation), the analysis in this report will be fairly limited.

II. Comparison to Alternative Rate Schedules

While Schedule 29 is not limited to a specific end use, one of its main purposes was to provide an new option that alleviated the very high average energy cost for electrification customers with low utilization. PacifiCorp also has a transition rate specific to electric vehicle chargers, Schedule 45, that was intended to ease the costs to these very low load factor customers until utilization increased. However, Schedule 45 is currently nearing the 8th year of the 10 year transition period to standard rates and low utilization of some charging stations still remains a barrier to electrification.

To better understand how Schedule 29 could provide savings for low load factor customers relative to standard general service rate schedules and to the current Schedule 45, a comparison of average price under different schedules for DC fast chargers was prepared. Bill estimates were calculated at 1%, 3%, and 5% load factors. Calculations were done assuming three common DC Fast Charger load size denominations of 150 kW, 250 kW, and 750 kW. Table 2 shows this average price comparison of Schedule 29 to other rate schedules alternatives.

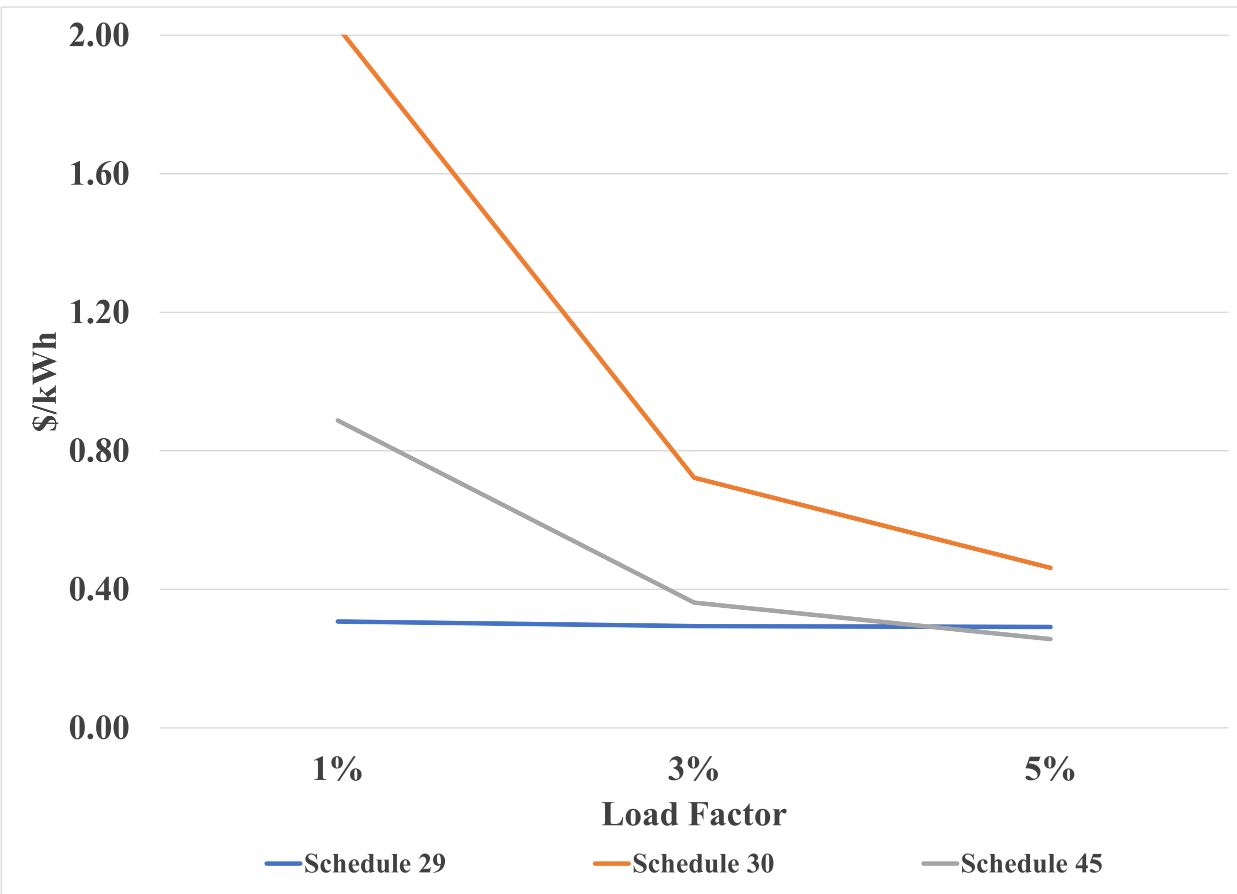
Table 2. Comparison of Average Price Across Different Load Sizes and Load Factors

Schedule 29			
Load Size	**1% Load Factor ($/kWh)**	**3% Load Factor ($/kWh)**	**5% Load Factor ($/kWh)**
150 kW	0.32	0.30	0.29
250 kW	0.31	0.29	0.29
750 kW	0.29	0.29	0.29
Schedule 28			
Load Size	**1% Load Factor ($/kWh)**	**3% Load Factor ($/kWh)**	**5% Load Factor ($/kWh)**
150 kW	1.08	0.42	0.29
250 kW			
750 kW			
Schedule 30			
Load Size	**1% Load Factor ($/kWh)**	**3% Load Factor ($/kWh)**	**5% Load Factor ($/kWh)**
150 kW			
250 kW	2.02	0.72	0.46
750 kW	1.90	0.68	0.44
Schedule 45			
Load Size	**1% Load Factor ($/kWh)**	**3% Load Factor ($/kWh)**	**5% Load Factor ($/kWh)**
150 kW	0.92	0.37	0.26
250 kW	0.89	0.36	0.26
750 kW	0.84	0.34	0.25

Table 2 shows that Schedule 29 has significantly lower average rates than other schedules at load factors below 5% and is comparable to the current Schedule 45 rates at a 5% load factor. Load factors for DC Fast Chargers are often less than 3%, with PacificCorp's only adopter of Oregon Schedule 29 having a load factor of 0.5%. For this customer, Schedule 29 allows for a 33 cent per kWh rate as opposed to a rate that is upwards of a dollar per kWh on other rate schedules.

The lack of a demand charge means rates are relatively unaffected by very low load factors when compared to schedules that have a demand charge built in. Figure 1 below shows how significant this effect is at low load factors. These rate differences indicate that Schedule 29 operates as it was initially intended by helping to alleviate demand charges due to low load factor and keeping prices down for medium-sized non-residential customers, which can help support Oregon policy of supporting transportation electrification.

Figure 1. Comparison of Prices Across Load Factors for a 250 kW DC Fast Charger



III. Conclusion/Recommendation

Schedule 29 holds promise for helping to support transportation electrification, particularly for charging stations that experience low levels of utilization. Customer interest in program has been low, however electric vehicle fast charger customers may show greater interest in Schedule 29 as Schedule 45 nears its full transition to standard rates in May 2026. More promotion to key customers would raise awareness of this option for customers who could potentially benefit. A stronger time of use differential could also make Schedule 29 more attractive for customers who have greater control of the timing of their usage. It is recommended that Schedule 29 be converted from a pilot to an ongoing program.

Docket No. UE 433
Exhibit PAC/1916
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Calculation of Proposed Time-of-Use On-Peak Surcharges and Off-Peak Credits

February 2024

PacifiCorp
State of Oregon
12 Months Ended June 2023
Calculation of Proposed Time-of-Use On-Peak Surcharges and Off-Peak Credits

Schedule 23 Time-of-Use Option

Description	kWh	Price (¢/kWh)	Revenue
On-Peak	194,744,141	12.578	$24,494,495
Off-Peak	967,388,094	(2.532)	-$24,494,495
Total	1,162,132,235		$0

Schedule 29 Time-of-Use Option (Usages from Schedule 28 and 30 Proxies)

Description	kWh	Price (¢/kWh)	Revenue
On-Peak	552,952,067	13.014	$71,961,090
Off-Peak	2,842,038,720	(2.532)	-$71,961,090
Total	3,394,990,788		$0

Schedule 41 Time-of-Use Option

Description	kWh	Price (¢/kWh)	Revenue
On-Peak - Option A	11,109,862	12.030	$1,336,519
On-Peak - Option B	11,082,022	12.030	$1,333,170
Off-Peak	99,032,240	(2.696)	-$2,669,689
Total	121,224,125		$0

Western Energy Imbalance Market
36 Months Ended June 2023
Average of ELAP_PACE-APND, ELAP_PACW-APND, and MALIN_5_N101 Nodes

	Hour Ending PT																							
Month	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
7	35.16	30.13	28.17	27.18	27.62	30.38	27.18	27.17	26.93	29.32	31.93	35.23	36.51	39.97	44.29	47.40	52.89	57.09	68.21	80.47	59.64	48.28	41.37	35.24
8	45.71	42.03	39.88	39.16	39.95	43.32	43.01	38.59	35.67	37.19	39.35	42.67	45.29	53.73	59.23	66.56	67.40	79.82	110.53	99.29	63.66	54.03	51.04	45.81
9	45.68	43.98	42.03	41.48	42.85	46.84	48.90	45.64	40.86	41.08	41.15	43.70	45.16	51.66	56.50	66.79	78.68	106.55	137.74	124.72	75.75	60.61	54.35	47.52
10	43.81	42.10	40.64	40.51	42.99	47.20	50.20	51.66	47.54	45.34	44.40	43.39	45.86	43.78	44.88	46.97	49.23	68.06	74.99	58.01	53.02	50.50	49.41	44.56
11	46.05	45.24	45.32	45.88	49.19	53.63	55.91	52.65	49.17	45.05	44.25	42.62	40.94	40.24	42.30	53.39	66.20	75.48	62.29	61.04	57.63	53.87	53.14	47.81
12	90.47	87.30	86.53	86.96	94.43	104.32	109.29	108.94	103.03	96.82	93.01	90.18	84.77	81.22	87.06	102.37	126.83	136.37	124.53	120.33	117.25	111.13	103.44	92.50
1	61.13	59.25	59.31	60.42	63.67	69.69	75.92	78.21	65.19	61.38	56.91	53.10	49.75	47.87	50.45	62.36	77.58	82.47	80.64	77.01	73.32	67.92	66.30	61.05
2	48.20	46.83	46.88	47.67	52.80	60.90	65.65	56.88	42.83	38.34	35.88	32.38	29.98	26.61	28.43	35.88	53.11	73.91	83.30	74.05	64.84	59.71	55.17	49.52
3	43.60	42.03	41.29	42.47	46.16	53.36	58.37	54.55	44.89	41.56	37.47	33.70	28.93	25.99	25.46	30.27	35.39	45.94	55.07	61.37	57.46	54.01	51.28	45.37
4	48.71	44.65	43.39	43.36	48.75	55.84	57.70	49.80	44.19	41.41	37.62	35.10	34.50	31.37	31.71	33.31	36.90	46.35	60.27	76.39	73.88	64.22	58.68	50.66
5	26.21	24.70	23.64	22.22	24.75	30.24	27.15	22.56	20.13	20.25	19.94	19.38	24.15	24.09	22.53	24.45	25.84	29.79	40.04	44.61	42.47	36.04	35.95	29.49
6	23.65	20.50	18.98	18.93	19.06	22.96	19.10	19.02	19.72	21.50	22.94	23.86	26.71	27.43	28.30	30.17	32.59	35.59	39.21	45.66	44.77	33.38	33.11	26.98

Schedule 23/ Schedule 29 Time of Use

On-Peak	72.52
Off-Peak	47.20
Difference	$\boxed{(25.32)}$

Western Energy Imbalance Market
36 Months Ended June 2023
Average of ELAP_PACE-APND, ELAP_PACW-APND, and MALIN_5_N101 Nodes

	Hour Ending PT																							
Month	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
7	35.16	30.13	28.17	27.18	27.62	30.38	27.18	27.17	26.93	29.32	31.93	35.23	36.51	39.97	44.29	47.40	52.89	57.09	68.21	80.47	59.64	48.28	41.37	35.24
8	45.71	42.03	39.88	39.16	39.95	43.32	43.01	38.59	35.67	37.19	39.35	42.67	45.29	53.73	59.23	66.56	67.40	79.82	110.53	99.29	63.66	54.03	51.04	45.81
9	45.68	43.98	42.03	41.48	42.85	46.84	48.90	45.64	40.86	41.08	41.15	43.70	45.16	51.66	56.50	66.79	78.68	106.55	137.74	124.72	75.75	60.61	54.35	47.52
10	43.81	42.10	40.64	40.51	42.99	47.20	50.20	51.66	47.54	45.34	44.40	43.39	45.86	43.78	44.88	46.97	49.23	68.06	74.99	58.01	53.02	50.50	49.41	44.56
11	46.05	45.24	45.32	45.88	49.19	53.63	55.91	52.65	49.17	45.05	44.25	42.62	40.94	40.24	42.30	53.39	66.20	75.48	62.29	61.04	57.63	53.87	53.14	47.81
12	90.47	87.30	86.53	86.96	94.43	104.32	109.29	108.94	103.03	96.82	93.01	90.18	84.77	81.22	87.06	102.37	126.83	136.37	124.53	120.33	117.25	111.13	103.44	92.50
1	61.13	59.25	59.31	60.42	63.67	69.69	75.92	78.21	65.19	61.38	56.91	53.10	49.75	47.87	50.45	62.36	77.58	82.47	80.64	77.01	73.32	67.92	66.30	61.05
2	48.20	46.83	46.88	47.67	52.80	60.90	65.65	56.88	42.83	38.34	35.88	32.38	29.98	26.61	28.43	35.88	53.11	73.91	83.30	74.05	64.84	59.71	55.17	49.52
3	43.60	42.03	41.29	42.47	46.16	53.36	58.37	54.55	44.89	41.56	37.47	33.70	28.93	25.99	25.46	30.27	35.39	45.94	55.07	61.37	57.46	54.01	51.28	45.37
4	48.71	44.65	43.39	43.36	48.75	55.84	57.70	49.80	44.19	41.41	37.62	35.10	34.50	31.37	31.71	33.31	36.90	46.35	60.27	76.39	73.88	64.22	58.68	50.66
5	26.21	24.70	23.64	22.22	24.75	30.24	27.15	22.56	20.13	20.25	19.94	19.38	24.15	24.09	22.53	24.45	25.84	29.79	40.04	44.61	42.47	36.04	35.95	29.49
6	23.65	20.50	18.98	18.93	19.06	22.96	19.10	19.02	19.72	21.50	22.94	23.86	26.71	27.43	28.30	30.17	32.59	35.59	39.21	45.66	44.77	33.38	33.11	26.98

Irrigation Time of Use

On-Peak - Option A	65.27
On-Peak - Option B	81.91
Option A/B Average	73.59
Off-Peak	46.63
Difference	(26.96)

Docket No. UE 433
Exhibit PAC/1917
Witness: Robert M. Meredith

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Robert M. Meredith

Cost of Eliminating Payment Fees

February 2024

PacifiCorp
State of Oregon
Cost of Eliminating Payment Fees
12 Months Ending June 2023

Description	Fee Count	Fee	Total Annual Cost
Pay Station	69,133	$1.65	$114,069
Residential Card Payment	1,319,531	$1.99	$2,625,867
Non-Residential Card Payment	258,901	$7.99	$2,068,619
Total	1,647,565		**$4,808,555**