PACIFIC POWER.
A DIVISION OF PACIFICORP

825 NE Multnomah Street, Suite 2000
Portland, Oregon 97232

May 15, 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. 24-008/UE 439—PacifiCorp's 2023 Power Cost Adjustment Mechanism

In compliance with ORS 757.205, OAR 860-022-0025, and OAR 860-022-0030, PacifiCorp d/b/a Pacific Power (PacifiCorp or Company) submits for filing the following proposed tariff pages associated with Tariff P.U.C. OR No. 36, which sets forth all rates, tolls, charges, rules, and regulations applicable to electric service in Oregon. PacifiCorp requests an effective date of October 1, 2024.

A. Description of Filing

In Order No. 12-493, the Public Utility Commission of Oregon (Commission) approved a Power Cost Adjustment Mechanism (PCAM) to allow PacifiCorp to recover the difference between actual net power costs (NPC) incurred to serve customers and the base NPC established in PacifiCorp's annual transition adjustment mechanism (TAM) filing. The amount recovered from or refunded to customers for a given year is subject to the following parameters:

- Asymmetrical Deadband. Any variance between negative $15 million and positive $30 million will be absorbed by the Company.
- Sharing Band. Any variance above or below the deadband will be shared 90 percent by customers and 10 percent by the Company.
- Earnings Test. If PacifiCorp's earned return on equity (ROE) is within plus or minus 100 basis points of the allowed ROE, there will be no recovery from or refund to customers.
- Amortization Cap. The amortization of deferred amounts are capped at six percent of the revenue for the preceding calendar year.

On an Oregon-allocated basis, actual 2023 PCAM costs were approximately $154.1 million more than base PCAM costs established in the 2023 TAM (docket UE 400). The application of the deadband, sharing band, and earnings test results in a recovery of $121.9 million through the 2023 PCAM. Therefore, PacifiCorp is requesting a rate change. PacifiCorp is proposing to amortize this amount over two years. Consistent with ORS 757.220, PacifiCorp has identified a June 15, 2024 rate effective date in the tariff that has been filed in this proceeding. However, PacifiCorp expects this filing will be suspended and set for adjudication, which has occurred in most recent PCAM filings. As a result, PacifiCorp would recommend a schedule that sets rates for October 1, 2024.

In compliance with Order No. 17-524, PacifiCorp includes supporting direct testimony and exhibits from the following witnesses:

- **Jack Painter, Net Power Cost Specialist:** Provides discussion of how the PCAM balance was calculated for the Deferral Period; the main differences between adjusted actual net power costs and net power costs in rates; and PacifiCorp's participation in the energy imbalance market (EIM) with the California Independent System Operator and the benefits from EIM that are passed through to customers.
- **Judith M. Ridenour, Specialist Pricing and Cost of Service:** Provides discussion of proposed rate spread, rates, and revised tariff pages for the 2023 PCAM; and summary of the impact of the proposed rate change on customers' bills.

A differential worksheet indicating actual minus base power costs for each separate cost category in the PCAM on a gross cost and per megawatt-hour unit basis is included in the confidential workpapers accompanying this filing.

Confidential material supporting this filing is provided subject to the general protective order in this proceeding, Order No. 23-132. The information contained in the workpapers contains market sensitive pricing information that could harm PacifiCorp and its customers if released publicly.

B. Tariff Sheets

The following proposed tariff sheet is provided in Ms. Ridenour's Exhibit PAC/202.

Sheet	Schedule	Title
First Revision Sheet No. 206-2	Schedule 206	Power Cost Adjustment Mechanism – Adjustment

C. Requirements of OAR 860-022-0025 and OAR 860-022-0030

To support the proposed rates and meet the requirements of OAR 860-022-0025 and OAR 860-022-0030, PacifiCorp provides the description and support indicated in Section A above. Please refer to the exhibits of Ms. Ridenour for the calculation of the proposed rate changes and impacts of proposed price changes by rate schedule.

This proposed change will affect approximately 627,000 customers and would result in an overall annual rate increase of approximately $64.3 million, or 3.5 percent. Residential customers using 950 kilowatt-hours per month would see an average monthly bill increase of $4.34 per month as a result of this change.

D. Correspondence

PacifiCorp respectfully requests that all communications related to this filing be addressed to:

Oregon Dockets	Ajay Kumar
PacifiCorp	Assistant General Counsel
825 NE Multnomah Street, Suite 2000	825 NE Multnomah Street, Suite 2000
Portland, OR 97232	Portland, OR 97232
oregondockets@pacificorp.com	ajay.kumar@pacificorp.com

Additionally, PacifiCorp requests that all formal information 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

Informal inquiries may be directed to Cathie Allen, Regulatory Affairs Manager, at (503) 813-5934.

Sincerely,

Matthew McVee
Vice President, Regulatory Policy and Operations

Cc: Service List UE 434
Service List UE 421

CERTIFICATE OF SERVICE

I certify that I delivered a true and correct copy of **PacifiCorp's 2023 Power Cost Adjustment Mechanism Advice No. 24-008/UE 439** on the parties listed below via electronic mail in compliance with OAR 860-001-0180.

Service List
UE 421

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Dated this 15th day of May, 2024.

Carrie Meyer
Advisor, Regulatory Operations

CERTIFICATE OF SERVICE

I certify that I delivered a true and correct copy of **PacifiCorp's 2023 Power Cost Adjustment Mechanism Advice No. 24-008/UE 439** on the parties listed below via electronic mail in compliance with OAR 860-001-0180.

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Dated this 15th day of May, 2024.

Carrie Meyer

Carrie Meyer
Advisor, Regulatory Operations

REDACTED
Docket No. UE 439
Exhibit PAC/100
Witness: Jack Painter

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Direct Testimony of Jack Painter

May 2024

TABLE OF CONTENTS

ATTACHED EXHIBIT

I. INTRODUCTION AND QUALIFICATIONS

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

A. My name is Jack Painter and my business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My title is Net Power Cost Specialist.

Q. Briefly describe your education and professional experience.

A. I received a Bachelor of Arts degree in Business Administration with a Finance major from Washington State University in 2007. I have been employed by PacifiCorp since 2008 and have held positions in the regulation and jurisdictional loads departments. I joined the regulatory net power costs group in 2019 and assumed my current role as a Net Power Cost Specialist in 2020.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have previously provided testimony to the public utility commissions in Oregon, California, Idaho, Utah, Washington, and Wyoming.

II. PURPOSE OF TESTIMONY

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

A. My testimony presents and supports PacifiCorp's calculation of the Power Cost Adjustment Mechanism (PCAM) costs for the 12-month period of January 1 through December 31, 2023 (Deferral Period). More specifically, I provide the following:

- Background on the PCAM and an accounting of how the PCAM balance was calculated for the Deferral Period;
- Discussion of the main differences between adjusted actual net power costs (Actual NPC) and net power costs in rates (Base NPC); and

- Discussion about PacifiCorp's participation in the Western Energy Imbalance Market (WEIM) with the California Independent System Operator (CAISO) and the benefits from WEIM that are passed through to customers.

Q. Are additional witnesses presenting testimony specifically for the PCAM and Rate Schedule 206 in this case?

A. Yes. Company witness Judith M. Ridenour, Pricing and Cost of Service Specialist, provides testimony on the proposed Schedule 206 rates.

III. SUMMARY OF THE PCAM DEFERRAL CALCULATION

Q. Please briefly describe PacifiCorp's PCAM authorized by the Public Utility Commission of Oregon (Commission).

A. Commission Order No. 12-493 approved a PCAM to allow PacifiCorp to recover the difference between actual PCAM costs incurred to serve customers and the base PCAM costs established in PacifiCorp's annual transition adjustment mechanism (TAM) filing.[1] PCAM costs include NPC and Production Tax Credits (PTC).

Q. Please summarize the calculation of the PCAM deferral included in this filing.

A. For the Deferral Period, on an Oregon-allocated basis, actual PCAM costs are $154.1 million more than base PCAM costs established in docket UE 400 (2023 TAM). The application of the deadband, sharing band, and earnings test results in a recovery of $121.9 million through the 2023 PCAM.

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[1] *In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Case*, Docket No. UE 246, Order No. 12-493 (Dec. 20, 2012).

Q. Have you provided detailed support for the calculation of the PCAM balance with your testimony?

A. Yes. Exhibit PAC/101 is a summary of the calculation of PacifiCorp's 2023 PCAM deferral on a monthly basis. Detailed workpapers supporting Exhibit PAC/101 are provided separately.[2]

IV. PCAM DEFERRAL CALCULATION

Q. Please describe the calculation of the PCAM deferral included in this filing.

A. The PCAM deferral is calculated on a monthly basis by comparing actual PCAM costs to base PCAM rates on a per-unit basis. The amount recovered from or refunded to customers for a given year is subject to the following parameters:

- Asymmetrical Deadband: Any PCAM difference between negative $15 million and positive $30 million will be absorbed by the Company.
- Sharing Band: Any PCAM difference above or below the deadband will be shared 90 percent by customers and 10 percent by PacifiCorp.
- Earnings Test: If PacifiCorp's earned return on equity (ROE) is within plus or minus 100 basis points of the authorized ROE, there will be no recovery from or refund to customers.
- Amortization Cap: The amortization of deferred amounts is capped at six percent of the revenue for the preceding calendar year.

For the Deferral Period the earned ROE was 0.82 percent which was more than 100 basis points lower than the 9.5 percent authorized ROE. Because the deferral balance exceeded the deadband, and after applying the sharing band, PacifiCorp is

[2] Confidential workpapers are provided pursuant to the Notice of Use of General Protective Order No. 23-132 filed in this proceeding.

allowed to request a rate change to Schedule 206. A summary of the deferral calculation is shown in Table 1.

Table 1
Summary of PCAM Account Balance

Calendar Year 2023 PCAM Deferral	
Actual PCAM Costs ($/MWh)	$ 39.97
Base PCAM Costs ($/MWh)	29.00
PCAM Cost Differential ($/MWh)	10.97
Oregon Retail Load (MWh)	13,949,228
PCAM Differential*	$ 153,102,187
Situs Resource True-Up*	965,609
Total PCAM Differential*	154,067,797
Total Deferrable ABOVE Deadband	124,067,797
Total Deferrable BELOW Deadband	-
Oregon Deferral at 90% Sharing	111,661,017
Interest Accrued through December 31, 2023	3,938,857
Oregon Deferral at 90% Sharing after Earning Test	115,599,874
Interest Accrued January 1, 2024 through September 30, 2024	6,311,588
Requested PCAM Recovery	**$ 121,911,462**

* *Calculated monthly*

Q. How is PacifiCorp proposing to amortize the balance?

A. PacifiCorp is proposing to amortize the balance over two years, beginning October 1, 2024, consistent with the amortization cap as identified above. This results in an annual rate increase of $64.3 million including interest during amortization.

Q. How is the monthly PCAM differential calculated?

A. As previously noted, on a monthly basis, actual PCAM costs are compared to base PCAM costs on a per-unit basis. PCAM costs are established in the Oregon TAM and include NPC and PTCs. WEIM benefits are embedded in NPC. Any differences in the system per-unit cost are multiplied by the actual megawatt-hours (MWh) of Oregon retail sales in that month to determine Oregon's share of any differential. The calculation uses the following formula:

$$(PCAMC_a \div Load_a) - (PCAMC_b \div Load_b) = \text{System PCAM Unit Cost Differential}$$

$$\text{System PCAM Unit Cost Differential} \times Load_o + (SR_a - SR_b) = \text{PCAM Differential}$$

Where:

$PCAMC_a$	= Total-company Adjusted Actual NPC (Excluding Situs Resources) plus other costs/benefits reflected in Oregon TAM
$Load_a$	= Actual System Retail Load
$PCAMC_b$	= Total-company Base NPC (Excluding Situs Resources) adjusted for Direct Access plus other costs/benefits reflected in Oregon TAM
$Load_b$	= Base System Retail Load
$Load_o$	= Actual Oregon Retail Load
SR_a	= Actual Situs Resource Value
SR_b	= Forecast Situs Resource Value

The cumulative PCAM differential (under- or over-recovery) is first compared against the asymmetrical deadband. Cumulative PCAM differential amounts in excess of the asymmetrical deadband are then subject to the sharing band (90 percent customers, 10 percent Company). Monthly balances accrue interest at PacifiCorp's authorized rate of return in Oregon for 2023. The final step is to apply, if necessary, the earnings test to determine if any amount is eligible for recovery from or refund to customers. To the extent earnings are within plus or minus 100 basis points of the authorized ROE, no recovery or refund is allowed under the approved PCAM design.

Q. What were total-Company adjusted Actual NPC for the Deferral Period and how were they determined?

A. The total-company adjusted Actual NPC in the Deferral Period were approximately $2.499 billion. This amount captures all components of NPC as modeled by PacifiCorp's Aurora model in the Company's annual TAM filings. Specifically, it includes amounts booked to the following Federal Energy Regulatory Commission (FERC) accounts:

Account 447 – Sales for resale, excluding on-system wholesale sales and other revenues that are not modeled in Aurora

Account 501 – Fuel, steam generation; excluding fuel handling, start-up fuel (gas and diesel fuel, residual disposal) and other costs that are not modeled in Aurora

Account 503 – Steam from other sources

Account 547 – Fuel, other generation

Account 555 – Purchased power, excluding the Bonneville Power Administration residential exchange credit pass-through if applicable

Account 565 – Transmission of electricity by others.

Q. Does the Company have any updates to the potential FERC accounting change that was noted in your testimony in the 2022 PCAM proceeding?

A. Yes. On June 29, 2023, the FERC issued Order No. 898 (Docket No. RM21-11-000), Accounting and Reporting Treatment of Certain Renewable Energy Assets, to change the accounting required for certain types of costs that have been previously booked to

FERC Account 555 to be booked to FERC account 509.[3]

Q. Does FERC Order No. 898 impact the current PCAM?

A. No. The change from FERC account 555 to FERC account 509 for these costs becomes effective January 1, 2025.

Q. What costs will be affected by FERC's Order No. 898 beginning January 1, 2025?

A. The change in accounting affects the costs associated with greenhouse gas (GHG) allowances that have been booked to FERC account 555 and historically included in the PCAM in the Company's general ledger (GL) accounts. GL account 546516 includes GHG costs for wholesale sales into California which have historically been included in the PCAM.

Q. What adjustments are made to Actual NPC and why are they needed?

A. PacifiCorp adjusts Actual NPC to reflect the ratemaking treatment of several items, including:

- out of period accounting entries booked in the Deferral Period that relate to operations before implementation of the PCAM on January 1, 2013;
- buy-through of economic curtailment by interruptible industrial customers;
- revenue from a contract related to the Leaning Juniper wind resource;
- costs for situs-assigned resources/programs in Oregon, California, and Utah;
- avian curtailment at specific wind farms;
- the exclusion of Rolling Hills wind farm from Oregon rates (consistent with docket UE 200);
- coal inventory adjustments to reflect coal costs in the correct period;

[3] *File Rule*, 183 FERC ¶ 61,205, Docket No. RM21-11-000 (Jun. 29, 2023) *available at* https://www.ferc.gov/media/order-no-898

- reductions to coal costs for management overtime, 50 percent of management incentive compensation, and legal fees related to fines and citations;
- adjustments related to liquidated damages that occurred outside the Deferral Period (all liquidated damage fees are booked in accordance with generally accepted accounting principles); and
- situs assignment of Reasonable Energy Price adjustments to qualifying facilities as described in the 2020 Inter-Jurisdictional Allocation Protocol (2020 Protocol).

Q. Please summarize the Direct Access (DA) load included in the PCAM.

A. Each year Base NPC is set in the TAM. After Base NPC is determined, certain customers have the option to move to DA and purchase energy from an Electricity Service Provider. In the PCAM, Base NPC is adjusted for the lost DA load.

Q. Please summarize the PTCs included in the PCAM.

A. PTCs forecast in the TAM are also included in the PCAM. In the 2023 TAM, PTC benefits were calculated using PacifiCorp's combined federal and state income tax rate that was effective in 2018. On a total-company basis, actual PTCs were $46 million lower than PTCs in the 2023 TAM due to generation variances.

Q. Please describe the true-up of certain Oregon-situs resources included in the PCAM.

A. The PCAM includes a true-up of the value of energy from solar facilities procured to satisfy the solar capacity standard in ORS 757.370. Consistent with the Commission-approved 2020 Protocol, these resources are situs-assigned to Oregon. Base NPC established in the TAM includes a situs credit for the market value of the solar energy.

In the PCAM, the actual market value of the solar energy is compared to the prior forecast, and the difference is included in the balancing account.

Additionally, the PCAM includes a true-up for the situs assignment of certain reasonable energy price qualifying facilities. The actual reasonable energy price costs are compared to the forecast in the TAM and any difference is included in the balancing account.

Q. Are costs related to Western Power Pool's (WPP) Western Resource Adequacy Program (WRAP) and the CAISO WEIM Body of State Regulators (BOSR) included in the PCAM?

A. No. Both costs were included in the 2023 General Rate Case in docket UE 399 for rates effective on January 1, 2023.[4] Because this PCAM filing covers the 2023 deferral period, these costs are no longer included in the PCAM.

Q. What are situs-assigned resources?

A. Situs-assigned resources are renewable resources that the Company acquired on behalf of either individual states or customers in order to serve part or all of their energy needs by a renewable resource. Both the costs and benefits for these resources are situs-assigned to the state of origin. Non-participating states should not bear higher costs for these resources.

Q. Which resources or programs are considered situs-assigned?

A. There are currently ten resources or programs that are situs-assigned with four in Oregon, one in California, and five in Utah. The Oregon situs-assigned resources or programs are Black Cap Solar, Old Mill Solar, Oregon Community Solar, and the

[4] *In the Matter of the Application of PacifiCorp d/b/a Pacific Power for a General Rate Revision*, Docket No. UE 399, PAC/400, Wilding/26-28 (Mar. 1, 2022).

Oregon Solar Incentive Plan. The California situs-assigned resource or program is California Electric Service Schedule No. NB-136 Net Billing Service. The Utah situs-assigned resources or programs are Pavant III Solar for the Utah Subscriber Solar Program, Utah Electric Service Schedule No. 136 Transition Program for Customer Generators, Utah Electric Service Schedule No. 137 Net Billing Service for Customer Generators, Amor IX/Soda Lake Geothermal under Utah Electric Service Schedule No. 32, and Cove Mountain Solar 2, Graphite Solar, Appaloosa Solar 1A and 1B, and Rocket Solar under Utah Electric Service Schedule No. 34.

Q. How does the company treat situs-assigned resources in the PCAM?

A. The Company uses either the actual cost or the mark-to-market calculation, whichever is lower for NPC allocation purposes. This treatment will ensure that non-participating states will not pay costs higher than actual costs and only the costs that are above market will be situs-assigned to state of origin.

Q. Are there any exceptions to the changes the Company has made?

A. Yes. Black Cap Solar in Oregon is a Company leased resource that has continued the sole use of the mark-to-market calculation because there is no associated Power Purchase Agreement (PPA) cost for this resource in NPC. Additionally, because the Utah Subscriber Solar Program and both Utah Schedule 32 and Schedule 34 resources are paid entirely by the respective customers, the lower of actual cost or market results in zero PPA costs.

Q. Is PacifiCorp requesting a rate change with this filing?

A. Yes. As described earlier, the earned ROE was more than 100 basis points lower than the authorized ROE and after applying the $30 million asymmetrical positive deadband, the 90 percent customer and 10 percent Company sharing band and interest, the requested PCAM recovery is $121.9 million, therefore, the 2023 PCAM qualifies for recovery. As noted above, PacifiCorp is requesting amortization of this deferral amount over two years beginning October 1, 2024.

V. SUMMARY OF THE NPC DIFFERENCES

Q. Please describe the Base NPC PacifiCorp used to calculate the NPC component of the PCAM deferral.

A. The Base NPC of $1.977 billion for the 2023 PCAM was set in Order No. 22-389 in docket UE 400. Base rates became effective January 1, 2023.

Q. Please describe Table 2 and the line items making up the difference between Actual NPC and Base NPC.

A. Table 2 displays the Base NPC approved by the Commission for the Deferral Period. The remainder of Table 2 is a breakout of the difference between Actual NPC and Base NPC, by cost category, on a total-company basis. The differences by category in Table 2 result from comparing Actual NPC to the Base NPC effective during the Deferral Period. Actual NPC were higher than Base NPC due to a $39 million increase in purchased power expense, a $127 million increase in natural gas expense, a $27 million increase in wheeling and other expenses, and a $389 million decrease in wholesale sales revenue (which increases NPC), which were partially offset by a $78 million decrease in coal fuel expense.

Table 2
Net Power Cost Reconciliation ($millions)

Base NPC	$	1,977
Increase/(Decrease) to NPC:		
Wholesale Sales Revenue		389
Purchased Power Expense		39
Coal Fuel Expense		(78)
Natural Gas Expense		127
Wheeling, Hydro and Other Expense		27
Settlement Adjustment		19
Total Increase/(Decrease)		522
Adjusted Actual NPC	$	2,499

Q. What are the main drivers of increased NPC in 2023?

A. For 2023, the two main drivers for increased NPC compared to Base NPC were coal fuel supply constraints and inaccurate modeling of wholesale sales leading to an overall increase in natural gas generation, purchased power, and a reduction in wholesale sales. Coal supply constraints which began at the end of calendar year 2022, continued through 2023 and still impact the Company today, having an overarching influence on all components of actual system operations. These constraints cause the coal generation in Base NPC to be replaced by natural gas generation and market purchases, and at the same time also limit the Company's ability to make profitable wholesale sales transactions.

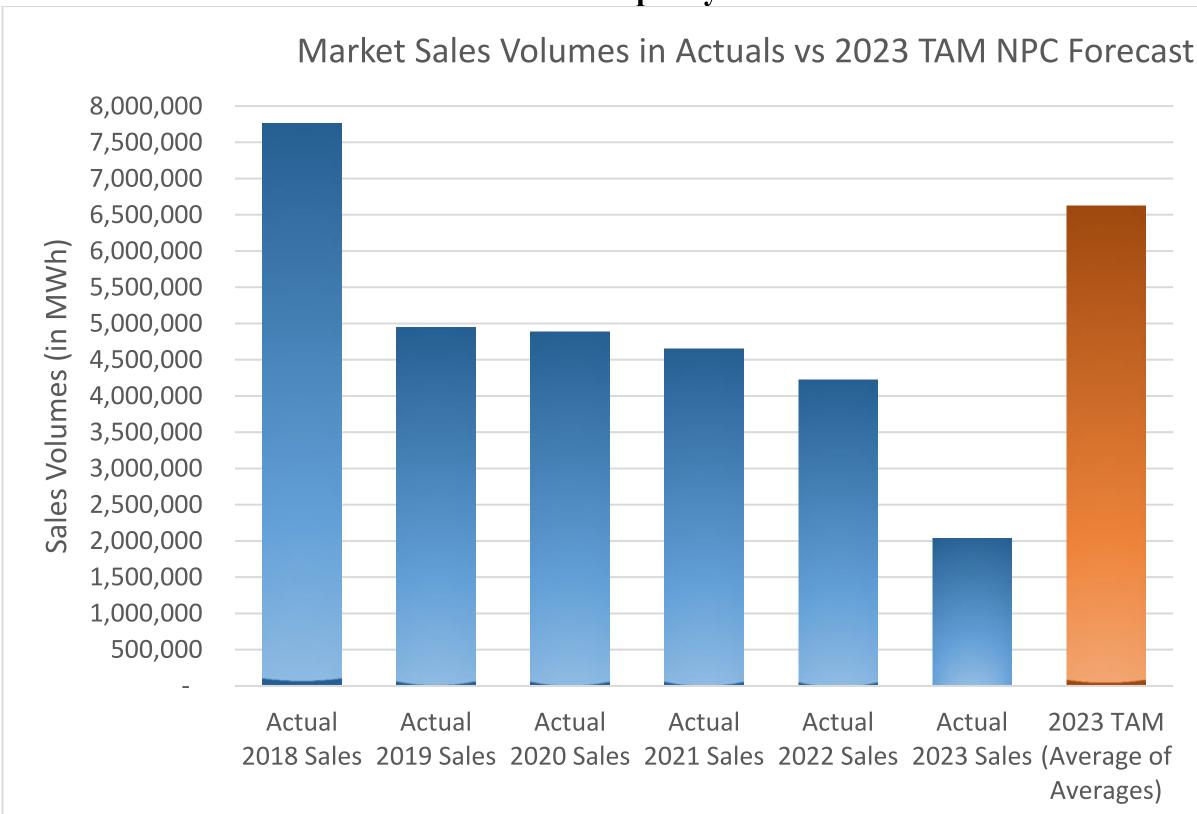
Q. Please explain the changes in wholesale sales revenue.

A. Wholesale sales volumes declined relative to Base NPC due to coal supply constraints and the overstatement of wholesale volumes in the TAM forecast modeling. When actual market conditions differ from normalized forecast conditions in the power cost production model, the opportunities for the Company to sell excess generation to the market are limited. Overall, the above market and system dynamics decreased wholesale sales revenue by $389 million compared to Base NPC. While the average price of actual wholesale market transactions, represented in the power cost production model as short-term firm and system balancing sales, was $81.97/MWh, or slightly lower than the average price in Base NPC, actual wholesale market transaction volumes were 4,935 gigawatt-hours (GWh), or 74 percent, lower than Base NPC.

As stated above, variances between Actual and Base NPC for wholesale sales are also partially attributable to the TAM forecast modeling of market depth which overstates actual wholesale sales volumes.[5] As shown in Figure 1 below, the 2023 TAM over-forecast wholesale sales using a 50th percentile market depth methodology based on historical monthly sales across four-years, which does not match the trend in decreasing wholesale sales volumes.

[5] The TAM refers to market depth as market capacity limits.

Figure 1
Market Capacity



Q. Please explain the changes in purchased power expense.

A. Overall, actual purchased power expense increased $39 million over Base NPC because actual market purchase volumes, represented in the power cost production model as short-term firm and system balancing purchases, increased, which were primarily a result of decreased coal generation volumes. Actual market purchase volumes increased by 1,203 GWh, or 18 percent compared to Base NPC.

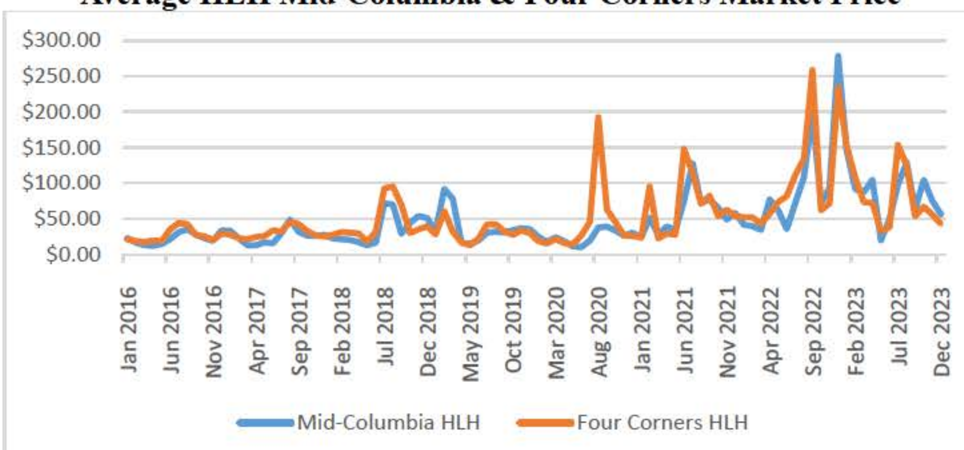
It is also important to note contextually that the average monthly price of market transactions at the Mid-Columbia and Four Corners market hubs has risen significantly since 2021. Between 2016 and 2020, the average monthly Heavy Load Hour (HLH) market price at the Mid-Columbia market hub was $29.27/MWh and

$35.11/MWh at the Four Corners market hub while the average monthly HLH market price in 2023 was $85.51/MWh and $81.12/MWh respectively. Table 3 and Figure 2 illustrate these significant market price increases impacting 2023 NPC.

Table 3
Average HLH Mid-Columbia & Four Corners Market Price

Year	Mid-C HLH Average	Four-C HLH Average
2016-2020	$29.27	$35.11
2021	$58.36	$65.42
2022	$92.75	$102.59
2023	$85.51	$81.12

Figure 2
Average HLH Mid-Columbia & Four Corners Market Price



Q. **Please explain the changes in coal fuel expense.**

A. As discussed in my testimony above, coal supply shortages, primarily at the Hunter and Huntington plants, that began in the fourth quarter of 2022 and extended through 2023, had a significant impact on the Company's coal generating resources and total system operations. In addition to coal supply constraints in Utah, the Jim Bridger plants also had coal supply constraints in early 2023. Due to overall lower coal fuel availability, the Company had to adjust its overall system operations through increased natural gas resource output, increased purchased power, and reduced wholesale sales. Total coal fuel expense decreased because coal generation volume was 7,043 GWh, or 24 percent lower than Base NPC as presented in Table 4.

Table 4
Coal Generation

Year	Base GWh	Actual GWh	Variance	Percent
2021	31,492	31,590	98	0%
2022	31,513	28,391	(3,122)	-10%
2023	28,994	21,951	(7,043)	-24%

The coal supply shortages also increased the average cost of coal generation from $21.91/MWh in Base NPC to $25.38/MWh in the Deferral Period. Overall, the lower generation volume results in a decrease of $78 million in coal fuel expense, but the coal supply limitations impacted all other aspects of the Company's system operations and net power costs in 2023 as previously explained.

Q. Please describe the changes in natural gas fuel expense.

A. With a reduction in coal generating resource output in 2023, the Company increased output at its natural gas generating resources when compared to previous years. Overall, the total natural gas fuel expense in Actual NPC increased by $127 million compared to Base NPC due to an increase in natural gas generating volumes in the Deferral period of 3,208 GWh, or 30 percent higher than Base NPC, but was slightly offset by a decrease in the average cost of natural gas generation from $39.65/MWh in Base NPC to $39.61/MWh. Table 5 below shows how gas generation volumes have increased since 2020.

Table 5
Gas Generation

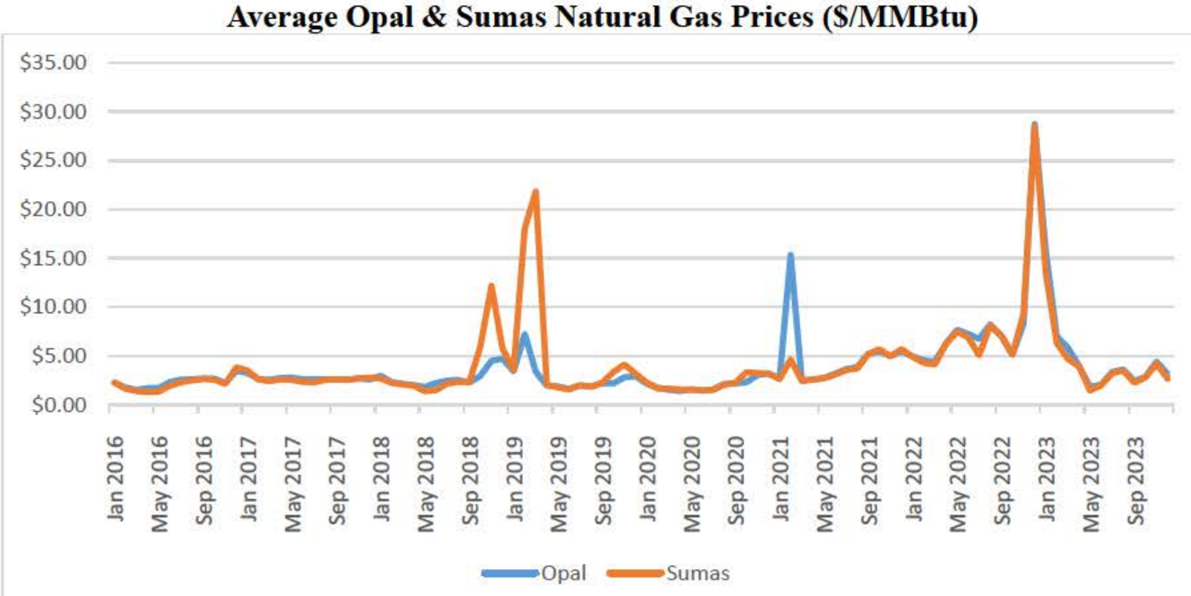
Year	Actual GWh
2020	12,042
2021	13,312
2022	13,686
2023	14,050

Like the significant increase in the average price of market power purchases discussed above, average natural gas prices have also seen a significant increase as compared to 2016 through 2020. Table 6 and Figure 3 below illustrate these increases impacting 2023 NPC.

Table 6
Average Opal & Sumas Natural Gas Prices ($/MMBtu)

Year	Opal Average	Sumas Average
2016-2020	$2.51	$3.19
2021	$4.80	$3.91
2022	$8.27	$8.09
2023	$4.70	$4.22

Figure 3
Average Opal & Sumas Natural Gas Prices ($/MMBtu)



Q. Please describe how extreme weather events have impacted NPC.

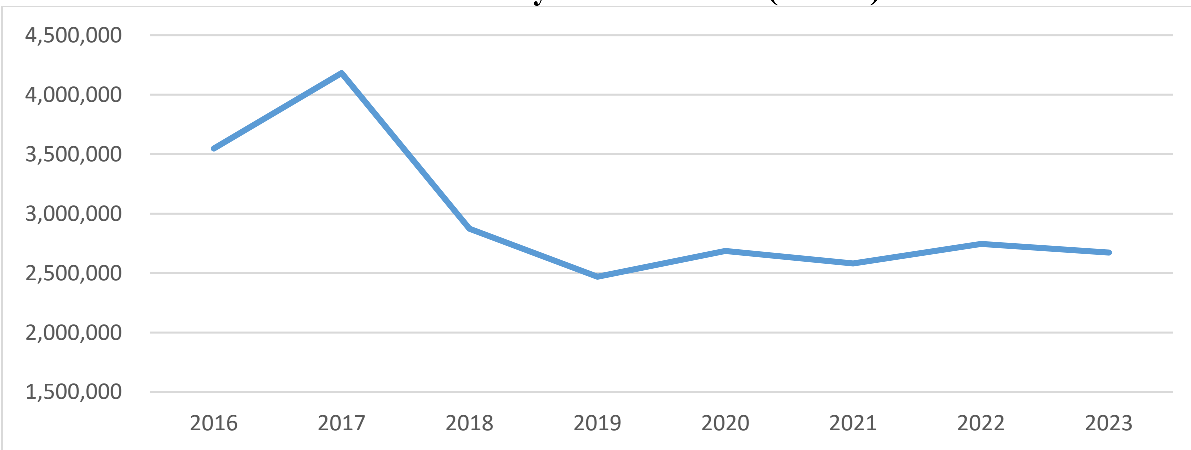
A. Ongoing drought in the West, which began in the summer of 2020, has continued to impact Actual NPC because it reduced the availability of the Company's hydro resources. In 2023, actual generation from the Company's hydro resources was 528 GWh (15 percent) lower than forecasted generation in Base NPC as shown in Table 7 below and needed to be replaced to meet customer demand.

Table 7
Hydro Generation

Year	Base GWh	Actual GWh	Variance	Percent
2020	4,650	3,037	(1,613)	-35%
2021	4,484	2,789	(1,695)	-38%
2022	3,365	2,936	(429)	-13%
2023	3,528	3,000	(528)	-15%

The estimated impact on total-Company NPC in 2023 due to decreased hydro MWhs caused by drought is $51 million. In the four years preceding the drought (2016-2019), average west hydro resource generation was 3.3 million MWhs while the average west hydro resource generation during the drought (2020-2023) was 2.7 million MWhs, a difference of 600 thousand MWhs, on average. Figure 4 below shows the decline over time.

Figure 4
Annual West Hydro Generation (MWhs)



Additionally, in December 2022, a historic winter cyclone event occurred across the majority of the United States, which impacted both market prices and natural gas prices, along with an increase in demand. The impacts of this event on both natural gas prices across the Company's delivery points and market power purchase prices were not only significant and elevated, but also carried over into January 2023. Table 8 and Table 9 below show the large variance between average January prices and the remaining average for the year prices between February and December at the Opal and Sumas natural gas hubs and Mid-Columbia and Four Corners market purchase power hubs.

Table 8
Opal and Sumas Average Monthly Price ($/MMBtu)

Month	Opal	Sumas
Jan	$15.85	$13.58
Feb - Dec	$3.68	$3.37

Table 9
Mid-Columbia and Four Corners Average Monthly Price ($/MWh)

Month	Mid-C HLH	Four-C HLH
Jan	$146.06	$152.35
Feb - Dec	$80.01	$74.64

VI. COAL SUPPLY CONSTRAINTS

Q. Please describe the many challenges the Company faced fueling its coal generating resources in 2023.

A. All of Utah's operating mines and some Wyoming mines experienced significant production difficulties and challenges in 2023 due to geological, logistical, and financial challenges. The most significant challenge was the mine fire that occurred at American Consolidated Natural Resources' (ACNR) Lila Canyon mine. The mine had produced more than 25 percent of Utah's coal production in recent years and stopped production in September 2022. ACNR announced the permanent closure of the Lila Canyon mine in November 2023 after determining that it was not possible to safely remediate and operate the mine.

In 2023, all of PacifiCorp's Utah coal suppliers and a major Wyoming coal supplier operated under *force majeure* declarations that resulted in significant delivery shortfalls of PacifiCorp's contracted coal supply. Consequently, the Utah coal mines experienced a 35 percent decrease in coal production from 10.7 million tons in 2022 to 6.9 million tons. Table 10 below highlights recent Utah coal market production data.

Table 10

Utah Coal Production by Supplier (source MSHA)

	TONS			**Change**	
	2021	**2022**	**2023**	**2022 v. 2023**	**%**
Bronco Utah Operations, LLC	1,170,988	1,062,707	798,023	(264,684)	-25%
Wolverine Fuels, LLC	6,845,083	6,425,241	5,477,050	(948,191)	-15%
ACNR Holdings, Inc.	3,470,644	2,281,289	159,240	(2,122,049)	-93%
Gentry Mountain Mining, LLC	512,951	599,770	419,592	(180,178)	-30%
Alton Coal Development, LLC	434,165	354,265	66,659	(287,606)	-81%
	12,433,831	10,723,272	6,920,564	(3,802,708)	-35%

Additionally, challenges in the U.S. coal market in 2022 due to historically low coal inventories and soaring natural gas prices led many utilities to increase coal purchases for generation and to restock depleted coal inventories. In many coal basins, coal pricing more than doubled in 2022 and remained high into 2023. This effect on coal pricing was exacerbated by the war in Ukraine, when many U.S. mines, including mines in Utah and Colorado, rushed to take advantage of high coal prices by exporting coal to Europe.

Q. What did the Company do to acquire additional coal supply in 2023?

A. The Company explored economic coal from possible sources. PacifiCorp contracted with a new supplier in 2023, Gentry Mountain Mining (Gentry), for additional coal supply for the Hunter plant. The Gentry coal supply agreements were designed to purchase all known economically-available Utah coal for use at the Utah plants. PacifiCorp continued to cooperate with the Hunter plant's co-owners to deliver coal from one of the plant co-owner's mine in Colorado. PacifiCorp even excavated a small amount of coal from the buried coal pile at the Gadsby plant, a converted natural gas plant in Salt Lake City, and delivered the coal to the Hunter plant. PacifiCorp also continued to transport coal from the Rock Garden safety pile to the

Huntington plant. This activity continued through September 2023 when the Rock Garden inventory was completely depleted.

PacifiCorp also procured coal from the North Antelope Rochelle Mine (ARM) in Wyoming's Powder River Basin for the first time for the Jim Bridger plant. Historically, Jim Bridger's coal has been supplied by the captive Bridger Coal Company mine and Lighthouse Resources' local Black Butte mine (Black Butte). PacifiCorp's deliveries from Black Butte were 0.88 million tons or [redacted] less than contracted in 2023. The shortfall occurred due to Black Butte's [redacted]. Black Butte declared *force majeure* in October 2023 [redacted]. Early in 2023, once the Black Butte delivery shortfall became apparent, PacifiCorp took steps to mitigate the shortfall. First, dispatch of the Jim Bridger plant was adjusted to account for the shortfall. Second, PacifiCorp contracted for the delivery of NARM coal which also required PacifiCorp to lease railcars. PacifiCorp received 0.33 million tons from NARM in 2023 to partially offset the reduction in Black Butte mine deliveries.

Q. How did the Company ensure existing coal suppliers in Utah did not suspend operations during 2023?

A. Bronco Utah Operations, LLC (Bronco) operates the Emery mine in Utah. PacifiCorp signed a coal supply agreement with Bronco in 2020 which allowed the Company to purchase [redacted] tons per year for calendar years 2021-2024 for coal to the Hunter Plant. Bronco notified PacifiCorp in late 2022 that it was unable to supply coal to the Hunter Plant at the current contract price and needed a commitment longer than the remaining two years of the contract for it to make the necessary capital investment for a reliable supply of coal to the Hunter plant. PacifiCorp evaluated the economic effects of this request and determined to adjust the Bronco contract terms to allow Bronco to obtain the necessary financing.

To avoid the unfavorable cost impacts to PacifiCorp's customers resulting from the unexpected loss of Bronco's coal supply, PacifiCorp amended its contract with Bronco in March 2023 to maintain Bronco as a coal supplier to serve Hunter through December 31, 2025. The contract amendment reduced Bronco's deliveries to the Hunter Plant as follows: (2023) [redacted] tons, (2024) [redacted] tons, and (2025) [redacted] tons. Despite PacifiCorp's best efforts to maintain the Emery mine as a reliable coal supplier, Bronco continued to struggle with production and ultimately delivered only 0.51 million tons in 2023, a shortfall of [redacted] tons from the contractual tons.

Q. How have the coal supply limitations impacted the Company's dispatch of its coal generating resources?

A. As a result of the *force majeure* declarations and resulting coal delivery shortfalls in Utah, the dispatch price of the Hunter and Huntington plants was adjusted to match the coal deliveries and assure system reliability throughout 2023. In other words, the dispatch of these coal resources was adjusted to ensure the Company had sufficient coal to serve load during high-demand periods. Additionally, the dispatch price of the Jim Bridger plant was adjusted for three months in early 2023 due to delivery shortfalls at the Black Butte mine which eventually resulted in a *force majeure* declaration. Ultimately due to these issues, the Company had to reduce its overall coal generating resource output in 2023 as illustrated in Table 5 above.

Q. How has the Company amended its coal contracts for future supply?

A. In February 2024, PacifiCorp amended the Hunter and Huntington coal supply agreements with Wolverine. The amended coal supply agreement with Wolverine for the Hunter plant's fuel supply [redacted] for the Hunter plant. Beginning in [redacted], the amendment facilitates additional coal production through renewed operations at the Fossil Rock mine in Emery County, Utah. Deliveries from the Fossil Rock mine will begin in [redacted]. When fully operational, the Fossil Rock mine will provide [redacted] tons per year to the Hunter plant. The contract amendment allows the Company to direct this coal to the Huntington plant as needed. This issue is addressed more thoroughly in the Company's 2025 Transition Adjustment Mechanism proceeding (docket UE 434).

Q. In the settlement of the 2024 TAM proceeding, PacifiCorp agreed to provide certain information reporting on the operation of the Company's coal facilities.[6] Has that information been provided in this proceeding?

A. Yes, that information has been included in the workpapers provided with this filing.

VII. COMPLIANCE COSTS

Q. Please generally describe the Ozone Transport Rule (OTR).

A. The OTR is the Environmental Protection Agency's (EPA) finalized federal plan for interstate transport of the 2015 ozone National Ambient Air Quality Standards, and had an effective date of August 4, 2023. The plan applied to 23 states, including Utah,

[6] *In the Matter of PacifiCorp, d/b/a Pacific Power, 2024 Transition Adjustment Mechanism*, Docket UE 420, Order No. 23-404, Appendix A at 6 (Oct. 27, 2023).

and includes requirements to eliminate significant contributions of ozone or ozone precursors (specifically, nitrogen oxides (NOx)) to nonattainment or maintenance areas in neighboring states. With respect to fossil fuel-fired electric generating units, the final rule sought to implement an allowance-based trading program where each unit was allocated a portion of the state's NOx budget during the ozone season (identified in the rule as May 1 – September 30).

Q. What is the current status of the OTR?

A. On July 27, 2023, the U.S. Tenth Circuit Court of Appeals granted the petitioners', including PacifiCorp's, motion to stay the EPA's final disapproval of Utah's OTR state implementation plan (SIP); and the EPA proposed approval of Wyoming's OTR SIP on August 14, 2023. While timelines cannot be predicted precisely, the OTR stay for the state of Utah is still under litigation with the U.S. Tenth Circuit Court of Appeals and is expected to remain in place at least through the 2024 ozone season. For Wyoming, the EPA published its final approval of Wyoming's interstate ozone transport plan in the Federal Register on December 19, 2023. The final approval of Wyoming's plan removes cross-state ozone transport requirements from electric generating units in the state, including PacifiCorp's generating units. As a result, Wyoming is not subject to the OTR federal implementation plan.

Q. Did the OTR impact NPC in 2023?

A. The stay was not granted until a week before the OTR was set to become effective, and the Company had to plan as if the OTR was going to be implemented for the Utah thermal generating units. Therefore, the Company needed to plan to alter its dispatch through market power purchases and its thermal generating resources as necessary to ensure there were sufficient NOx allowances to cover the generation. In 2023, the Company incurred $17 million in additional NPC to comply with the prospective OTR requirements.

Q. Are other environmental compliance costs included in Oregon customer rates?

A. Yes. All the Company's generation resources incur various types of environmental compliance costs and generation taxes, many of which are imposed by the state where the resource is located. These include costs like the Wyoming wind tax, and upgrades at generation facilities that are necessary to comply with environmental requirements like fish passage at hydroelectric plants or avian curtailments at wind facilities. These direct impacts to generation are consistently system allocated. Oregon customers pay these environmental compliance and generation tax costs incurred by resources that are used to serve Oregon customers.

VIII. IMPACT OF PARTICIPATING IN THE WEIM

Q. What is the CAISO WEIM?

A. The CAISO WEIM is an advanced real-time energy market that automatically finds low-cost energy to serve real-time consumer demand across the west by allowing participants to buy and sell power close to the time electricity is consumed. Since its launch in 2014, the WEIM has enhanced grid reliability, improved the integration of renewable resources, lowered carbon emissions, and generated significant cost savings for its participants.

Q. Are the actual benefits from participating in the WEIM included in the PCAM deferral?

A. Yes. Participation in the WEIM provides significant benefits to customers in the form of reduced Actual NPC. The benefits are embedded in Actual NPC through lower fuel costs and lower purchased power costs.

Q. What are the actual WEIM benefits included in the PCAM deferral?

A. CAISO's WEIM benefits report indicates that PacifiCorp received $154 million in benefits in 2023. Since inception of the WEIM, PacifiCorp has received $746 million in total benefits.

IX. CONCLUSION

Q. Please summarize your testimony.

A. The PCAM deferral of $121.9 million, including interest for the calendar year 2023 Deferral Period was accurately calculated in compliance with the PCAM tariff and previous Commission orders. The increase is primarily driven by coal supply limitations, inaccurate modeling of wholesale sales volumes, and extreme weather events impacting actual system operations.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 439
Exhibit PAC/101
Witness: Jack Painter

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Jack Painter

2023 PCAM Calculation

May 2024

Oregon Power Cost Adjustment Mechanism
January 1, 2023 - December 31, 2023
Exhibit/PAC 101 - Power Cost Adjustment Mechanism Calculation

Line No.		Reference	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Total
	Actual:														
1	Total Company Adjusted Actual NPC	(2.1)	$ 200,129,758	$ 210,331,667	$ 205,278,899	$ 162,978,343	$ 158,084,737	$ 173,837,481	$ 295,987,976	$ 296,222,879	$ 229,295,029	$ 171,168,583	$ 199,125,364	$ 196,770,410	$ 2,499,211,127
2	Actual Allocated PTC	(4.1)	(25,755,628)	(26,295,051)	(23,237,854)	(22,211,911)	(15,109,633)	(13,998,389)	(12,973,190)	(14,943,754)	(14,554,835)	(15,115,525)	(24,942,050)	(24,040,083)	(233,177,903)
3	Total PCAM Adjusted Actual Costs	Sum Lines 1 - 2	174,374,130	184,036,616	182,041,045	140,766,432	142,975,104	159,839,092	283,014,785	281,279,125	214,740,194	156,053,058	174,183,314	172,730,327	2,266,033,224
4	Actual System Retail Load	(8.1)	5,023,905	4,557,641	4,712,060	4,221,807	4,404,575	4,421,401	5,717,856	5,225,752	4,402,256	4,417,949	4,621,233	4,969,863	56,696,299
5	Actual PCAM Costs $/MWH	Line 3 / Line 4	$ 34.71	$ 40.38	$ 38.63	$ 33.34	$ 32.46	$ 36.15	$ 49.50	$ 53.83	$ 48.78	$ 35.32	$ 37.69	$ 34.76	$ 39.97
	Base:														
6	Total Company Base NPC	(3.1)	$ 126,108,015	$ 122,000,808	$ 139,672,155	$ 126,167,896	$ 132,884,449	$ 135,663,550	$ 268,600,965	$ 267,107,490	$ 169,684,084	$ 148,472,766	$ 147,582,134	$ 193,510,278	$ 1,977,454,591
7	Adjustment for Direct Access	(3.2)	(1,942,079)	(1,813,216)	(1,226,922)	(1,063,536)	(1,044,831)	(1,072,528)	(5,604,886)	(6,556,863)	(4,060,569)	(2,161,139)	(2,467,492)	(3,352,175)	(32,366,236)
8	Base Allocated PTC	(4.1)	(23,266,883)	(23,266,883)	(23,266,883)	(23,266,883)	(23,266,883)	(23,266,883)	(23,266,883)	(23,266,883)	(23,266,883)	(23,266,883)	(23,266,883)	(23,266,883)	(279,202,594)
9	Total PCAM Base Costs	Sum Lines 6 - 8	100,899,052	96,920,709	115,178,351	101,837,477	108,572,735	111,324,140	239,729,196	237,283,744	142,356,632	123,044,744	121,847,759	166,891,220	1,665,885,761
10	Base System Retail Load	(8.1)	5,003,518	4,410,236	4,602,746	4,337,537	4,506,819	4,835,400	5,487,364	5,340,747	4,639,991	4,514,528	4,629,222	5,131,261	57,439,369
11	Base PCAM Costs $/MWh	Line 9 / Line 10	$ 20.17	$ 21.98	$ 25.02	$ 23.48	$ 24.09	$ 23.02	$ 43.69	$ 44.43	$ 30.68	$ 27.26	$ 26.32	$ 32.52	$ 29.00
12	System PCAM Unit Cost Differential $/MWh	Line 5 - Line 11	$ 14.54	$ 18.40	$ 13.61	$ 9.86	$ 8.37	$ 13.13	$ 5.81	$ 9.40	$ 18.10	$ 8.07	$ 11.37	$ 2.23	$ 10.97 #
13	Oregon Retail Load	(8.1)	1,299,046	1,179,566	1,243,098	1,065,840	1,037,300	1,067,777	1,277,847	1,256,215	1,005,032	1,082,072	1,180,497	1,254,938	13,949,228
	Deferral:														
14	Monthly PCAM Differential - Above or (Below) Base	Line 12 * Line 13	$ 18,892,367	$ 21,708,117	$ 16,917,541	$ 10,513,996	$ 8,682,014	$ 14,018,310	$ 7,423,218	$ 11,804,192	$ 18,190,295	$ 8,729,322	$ 13,422,870	$ 2,799,945	$ 153,102,187
15	Oregon Situs Resource True-Up	(7.1)	55,226	56,476	29,184	35,772	151,403	97,654	199,496	242,270	182,125	(49,294)	(21,015)	(13,687)	965,609
16	Total Monthly PCAM Differential - Above or (Below) Base	Line 14 + Line 15	18,947,593	21,764,592	16,946,725	10,549,768	8,833,417	14,115,964	7,622,715	12,046,462	18,372,419	8,680,029	13,401,855	2,786,258	154,067,797
17	Cumulative PCAM Differential - Above or (Below) base		18,947,593	40,712,185	57,658,910	68,208,678	77,042,095	91,158,059	98,780,774	110,827,236	129,199,655	137,879,684	151,281,539	154,067,797	
18	Positive Deadband - ABOVE Base	Order. 12-493	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000
19	Negative Deadband - BELOW Base	Order. 12-493	(15,000,000)	(15,000,000)	(15,000,000)	(15,000,000)	(15,000,000)	(15,000,000)	(15,000,000)	(15,000,000)	(15,000,000)	(15,000,000)	(15,000,000)	(15,000,000)	(15,000,000)
20	Amount Deferrable - ABOVE Deadband		-	10,712,185	16,946,725	10,549,768	8,833,417	14,115,964	7,622,715	12,046,462	18,372,419	8,680,029	13,401,855	2,786,258	124,067,797
21	Amount Deferrable - BELOW Deadband		-	-	-	-	-	-	-	-	-	-	-	-	-
22	Total Incremental Deferrable	Line 20 + Line 21	-	10,712,185	16,946,725	10,549,768	8,833,417	14,115,964	7,622,715	12,046,462	18,372,419	8,680,029	13,401,855	2,786,258	124,067,797
23	Total Incremental Deferral After 90%/10% Sharing Band	Line 22 * 90%	$ -	$ 9,640,967	$ 15,252,052	$ 9,494,791	$ 7,950,076	$ 12,704,368	$ 6,860,443	$ 10,841,816	$ 16,535,177	$ 7,812,026	$ 12,061,670	$ 2,507,632	$ 111,661,017
	Energy Balancing Account:														
24	Monthly Interest Rate	Note 1	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	0.59%	
25	Beginning Balance	Prior Month Line 28	$ -	$ -	$ 9,669,524	$ 25,024,038	$ 34,695,200	$ 42,874,365	$ 55,870,359	$ 63,082,108	$ 74,329,747	$ 91,354,245	$ 99,730,608	$ 112,418,826	$ -
26	Incremental Deferral	Line 23	-	9,640,967	15,252,052	9,494,791	7,950,076	12,704,368	6,860,443	10,841,816	16,535,177	7,812,026	12,061,670	2,507,632	111,661,017
27	Interest	Line 24 * (Line 25 + 50% x Line 26)	-	28,557	102,462	176,371	229,089	291,626	351,307	405,823	489,320	564,338	626,548	673,416	3,938,857
28	Ending Balance	∑ Lines 25:27	$ -	$ 9,669,524	$ 25,024,038	$ 34,695,200	$ 42,874,365	$ 55,870,359	$ 63,082,108	$ 74,329,747	$ 91,354,245	$ 99,730,608	$ 112,418,826	$ 115,599,874	$ 115,599,874
	Earnings Test:														
29	Earned Return on Equity	(9.1)													0.82%
30	Allowed Return on Equity	UE-399													9.50%
31	100bp ROE Revenue Requirement														$ 27,731,436
32	Allowed Deferral After Earning Test														212,995,370
33	Total Deferred														$ 115,599,874
34	Interest Accrued January 1, 2024 through September 30, 2024	Line 33 * (1 + 1.07109% / 12) ^ 9 - Line 33"													$ 6,311,588
35	**Requested PCAM Recovery**	Line 33 + Line 34													**$ 121,911,462**

Notes:

Note 1: 7.109% annual interest rate based on Oregon approved rate of return/weighted average cost of capital in docket UE 399 in effect beginning January 1, 2023.

Docket No. UE 439
Exhibit PAC/200
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Judith M. Ridenour

May 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 Judith M. Ridenour. My business address is 825 NE Multnomah Street, Suite 2000, Portland, Oregon 97232. My current position is Specialist, Pricing and Cost of Service, in the regulation department.

Q. Briefly describe your education and professional experience.

A. I have a Bachelor of Arts degree in Mathematics from Reed College. I joined the Company in the regulation department in October 2000. I assumed my present responsibilities in May 2001. In my current position, I am responsible for the preparation of rate design used in retail price filings and related analyses. Since 2001, with levels of increasing responsibility, I have analyzed and implemented rate design proposals throughout the Company's six-state service territory.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. I present PacifiCorp's proposed rate spread, rates, and revised tariff page for the 2023 Power Cost Adjustment Mechanism (PCAM) to recover the eligible costs identified by Company witness Jack Painter. I also present the impact of the proposed rate change on customers' bills.

III. PROPOSED RATE SPREAD AND RATES

Q. How does the Company propose to collect the 2023 PCAM eligible costs identified by Mr. Painter from customers?

A. As indicated by Mr. Painter, PacifiCorp proposes to collect the 2023 PCAM eligible costs from customers over a two-year period beginning October 1, 2024. Accounting for interest during amortization, the annual increase from the proposed rate change is $64.3 million.

Q. What rate spread has the Company used to set 2023 PCAM rates?

A. The Company used a generation rate spread to set the proposed PCAM rates, where rates are delineated by delivery voltage. This best reflects the types of costs recovered through the PCAM.

Q. Did you prepare an exhibit showing the proposed PCAM rate spread, rates and revenues?

A. Yes. Exhibit PAC/201 shows the proposed 2023 PCAM rate spread, rates and revenues.

Q. Please describe the Company's tariff rate schedule that collects the PCAM.

A. PacifiCorp has in place Schedule 206, Power Cost Adjustment Mechanism – Adjustment, designed to collect PCAM costs from customers. Schedule 206 currently contains rates which are collecting the 2021 PCAM amounts over a four-year period which began April 1, 2023 and rates which are collecting the 2022 PCAM amounts over a two-year period which began January 1, 2024.

Q. What is the rate effective date proposed by PacifiCorp?

A. Consistent with ORS 757.220, PacifiCorp has identified a June 15, 2024 rate effective date in the tariffs that have been filed in this proceeding. However, PacifiCorp expects this filing will be suspended and set for adjudication. As a result, PacifiCorp would recommend a schedule that sets rates for October 1, 2024. A rate effective date of October 1, 2024 will help ensure that this proceeding does not overlap with other rate increases that may occur during the winter heating season.

Q. Please describe Exhibit PAC/202.

A. Exhibit PAC/202 contains the proposed revised Schedule 206 tariff. As described in the applicability section of the tariff, PCAM rates do not apply to customers who took service under direct access during the accrual year for each PCAM. In order to properly apply rates to the correct customers for both the ongoing 2021 PCAM and 2022 PCAM collections and the proposed 2023 PCAM collections, the Company proposes to keep these rates separate in the tariff.

IV. COMPARISON OF PRESENT AND PROPOSED CUSTOMER RATES

Q. What are the overall rate effects of the changes proposed in this filing?

A. The overall proposed effect is a rate increase of $64.3 million or 3.5 percent, on a net basis. The rate change varies by customer type. Page one of Exhibit PAC/203 shows the estimated effect of PacifiCorp's proposed prices by delivery service schedule both excluding (base) and including (net) applicable adjustment schedules. The net rates in Columns 7 and 10 exclude effects of the Low Income Bill Payment Assistance Fund (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).

Q. Did you prepare an exhibit that shows the impact on customer bills as a result of the proposed PCAM rate change?

A. Yes. Exhibit PAC/203, beginning on page two, contains monthly billing comparisons for customers at different usage levels served on each of the major delivery service schedules. Each bill impact is shown in both dollars and percentages. These bill comparisons include the effects of all adjustment schedules including Schedule 91, Schedule 92, Schedule 98, Schedule 290, and Schedule 291.

Q. What is the estimated monthly impact to an average residential customer?

A. The estimated monthly impact to the average residential customer using 950 kilowatt-hours per month is a bill increase of $4.34.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 439
Exhibit PAC/201
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Judith M. Ridenour

Proposed 2023 PCAM Rate Spread and Rates

May 2024

PACIFIC POWER
State of Oregon
2023 Power Cost Adjutment Mechanism (PCAM) - Adjustment, Proposed for Schedule 206

FORECAST 12 MONTHS ENDED DECEMBER 31, 2025

Line No.	Sch No.	Description		MWh[1]	Generation Rate Spread	Proposed 2023 PCAM in Sch 206 Rates (¢/kWh)	Proposed 2023 PCAM in Sch 206 Revenues ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	4	Residential		5,787,620	40.563%	0.450	$26,044
2	23	Gen. Svc. < 31 kW	Secondary	1,160,255	7.661%	0.424	$4,919
3			Primary	1,877	0.011%	0.384	$7
4	28	Gen. Svc. 31 - 200 kW	Secondary	2,043,261	13.321%	0.418	$8,541
5			Primary	21,451	0.137%	0.409	$88
6	30	Gen. Svc. 201 - 999 kW	Secondary	1,252,474	8.008%	0.410	$5,135
7			Primary	77,805	0.496%	0.409	$318
8	41	Agricultural Pumping Service	Secondary	234,910	1.480%	0.404	$949
9			Primary	0	0.000%	0.366	0
10	48	Large General Service >= 1,000 kW	Secondary	570,908	3.622%	0.407	$2,324
11			Primary	2,171,323	13.283%	0.392	$8,512
12			Transmission	1,934,880	11.319%	0.375	$7,256
13	47	Partial Req. Svc. >= 1,000 kW	Primary	36,803		*0.392*	$144
14			Transmission	6,576		*0.375*	$25
15	15	Outdoor Area Lighting Service		2,128	0.019%	0.559	$12
16	51	Street Lighting Service Comp. Owned		7,898	0.059%	0.476	$38
17	53	Street Lighting Service Cust. Owned		8,821	0.019%	0.140	$12
18	54	Recreational Field Lighting		1,374	0.003%	0.140	$2
19		**Subtotal**		15,320,363	100.000%		$64,326
20		Employee Discount		*13,364*		*(0.113)*	($15)
21		**Total**		15,320,363			$64,311

[1] Includes tariff based lighting MWh.

Docket No. UE 439
Exhibit PAC/202
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Judith M. Ridenour

Proposed Tariff Schedule 206

May 2024

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 206

Monthly Billing (continued)

Calendar Year 2022 Accrual Period

Delivery Service Schedule	**Secondary**	**Primary**	**Transmission**
Schedule 4, per kWh	0.442¢		
Schedule 5, per kWh	0.442¢		
Schedule 15, per kWh	0.548¢		
Schedule 23, 723, per kWh	0.416¢	0.377¢	
Schedule 28, 728, per kWh	0.411¢	0.401¢	
Schedule 30, 730, per kWh	0.403¢	0.401¢	
Schedule 41, 741, per kWh	0.397¢	0.391¢	
Schedule 47, 747, per kWh	0.400¢	0.385¢	0.369¢
Schedule 48, 748, per kWh	0.400¢	0.385¢	0.369¢
Schedule 51, 751, per kWh	0.469¢		
Schedule 53, 753, per kWh	0.138¢		
Schedule 54, 754, per kWh	0.138¢		

(N)

Calendar Year 2023 Accrual Period

Delivery Service Schedule	**Secondary**	**Primary**	**Transmission**
Schedule 4, per kWh	0.450¢		
Schedule 5, per kWh	0.450¢		
Schedule 15, per kWh	0.559¢		
Schedule 23, 723, per kWh	0.424¢	0.384¢	
Schedule 28, 728, per kWh	0.418¢	0.409¢	
Schedule 30, 730, per kWh	0.410¢	0.409¢	
Schedule 41, 741, per kWh	0.404¢	0.366¢	
Schedule 47, 747, per kWh	0.407¢	0.392¢	0.375¢
Schedule 48, 748, per kWh	0.407¢	0.392¢	0.375¢
Schedule 51, 751, per kWh	0.476¢		
Schedule 53, 753, per kWh	0.140¢		
Schedule 54, 754, per kWh	0.140¢		

(N)

Docket No. UE 439
Exhibit PAC/203
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Judith M. Ridenour

Estimated Effect of Proposed Price Change and Monthly Billing Comparisons

May 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	$71,535	$857,610	$786,075	$97,579	$883,655	$0	0.0%	$26,044	3.0%	1
2	**Total Residential**		513,581	5,787,620	$786,075	$71,535	$857,610	$786,075	$97,579	$883,655	$0	0.0%	$26,044	3.0%	2
	Commercial & Industrial														
3	Gen. Svc. < 31 kW	23	86,033	1,162,132	$159,887	$15,211	$175,098	$159,887	$20,138	$180,025	$0	0.0%	$4,927	2.8%	3
4	Gen. Svc. 31 - 200 kW	28	10,658	2,064,712	$211,334	$34,045	$245,379	$211,334	$42,673	$254,008	$0	0.0%	$8,629	3.5%	4
5	Gen. Svc. 201 - 999 kW	30	847	1,330,279	$118,973	$20,033	$139,006	$118,973	$25,487	$144,459	$0	0.0%	$5,453	3.9%	5
6	Large General Service >= 1,000 kW	48	177	4,677,111	$357,556	$36,825	$394,381	$357,556	$54,916	$412,471	$0	0.0%	$18,091	4.6%	6
7	Partial Req. Svc. >= 1,000 kW	47	6	43,379	$5,048	$343	$5,391	$5,048	$512	$5,560	$0	0.0%	$169	4.6%	7
8	Dist. Only Lg Gen Svc >= 1,000 kW	848	1	0	$1,517	$574	$2,091	$1,517	$574	$2,091	$0	0.0%	$0	0.0%	8
9	Agricultural Pumping Service	41	7,884	234,910	$32,687	($277)	$32,410	$32,687	$672	$33,359	$0	0.0%	$949	2.9%	9
10	**Total Commercial & Industrial**		105,606	9,512,522	$887,002	$106,754	$993,756	$887,002	$144,971	$1,031,974	$0	0.0%	$38,218	3.8%	10
	Lighting														
11	Outdoor Area Lighting Service	15	5,833	8,157	$839	$327	$1,166	$839	$339	$1,178	$0	0.0%	$12	1.0%	11
12	Street Lighting Service Comp. Owned	51	1,210	20,858	$2,903	$1,268	$4,170	$2,903	$1,305	$4,208	$0	0.0%	$38	0.9%	12
13	Street Lighting Service Cust. Owned	53	296	8,821	$487	$307	$794	$487	$319	$806	$0	0.0%	$12	1.6%	13
14	Recreational Field Lighting	54	98	1,374	$91	$60	$150	$91	$62	$152	$0	0.0%	$2	1.3%	14
15	**Total Public Street Lighting**		7,437	39,210	$4,319	$1,962	$6,281	$4,319	$2,026	$6,345	$0	0.0%	$64	1.0%	15
16	**Subtotal**		626,624	15,339,352	$1,677,397	$180,251	$1,857,647	$1,677,397	$244,576	$1,921,973	$0	0.0%	$64,326	3.5%	16
17	Employee Discount		*867*	*13,364*	($445)	($41)	($486)	($445)	($56)	($501)	$0		($15)		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	$180,209	$1,861,146	$1,680,937	$244,520	$1,925,457	$0	0.0%	$64,311	3.5%	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
Monthly Billing Comparison
Delivery Service Schedule 4 + Cost-Based Supply Service
Residential Service - Single Family

	Monthly Billing*			Percent
kWh	Present Price	Proposed Price	Difference	Difference
100	$28.51	$28.96	$0.45	1.58%
200	$42.53	$43.44	$0.91	2.14%
300	$56.54	$57.91	$1.37	2.42%
400	$70.56	$72.39	$1.83	2.59%
500	$84.57	$86.85	$2.28	2.70%
600	$98.58	$101.32	$2.74	2.78%
700	$112.60	$115.80	$3.20	2.84%
800	$126.61	$130.27	$3.66	2.89%
900	$140.63	$144.75	$4.12	2.93%
950	**$147.64**	**$151.98**	**$4.34**	**2.94%**
1,000	$154.65	$159.21	$4.56	2.95%
1,100	$168.66	$173.68	$5.02	2.98%
1,200	$182.68	$188.16	$5.48	3.00%
1,300	$196.69	$202.63	$5.94	3.02%
1,400	$210.71	$217.10	$6.39	3.03%
1,500	$224.72	$231.57	$6.85	3.05%
1,600	$238.73	$246.04	$7.31	3.06%
2,000	$294.80	$303.93	$9.13	3.10%
3,000	$443.71	$457.41	$13.70	3.09%
4,000	$592.62	$610.89	$18.27	3.08%
5,000	$741.53	$764.37	$22.84	3.08%

* 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

kWh	Monthly Billing* Present Price	Proposed Price	Difference	Percent Difference
100	$25.46	$25.92	$0.46	1.81%
200	$39.48	$40.40	$0.92	2.33%
300	$53.49	$54.86	$1.37	2.56%
400	$67.51	$69.34	$1.83	2.71%
500	$81.53	$83.81	$2.28	2.80%
600	$95.54	$98.28	$2.74	2.87%
700	$109.56	$112.75	$3.19	2.91%
800	$123.57	$127.22	$3.65	2.95%
900	$137.59	$141.70	$4.11	2.99%
950	$144.60	$148.93	$4.33	2.99%
1,000	$151.60	$156.17	$4.57	3.01%
1,100	$165.61	$170.64	$5.03	3.04%
1,200	$179.63	$185.11	$5.48	3.05%
1,300	$193.64	$199.58	$5.94	3.07%
1,400	$207.66	$214.06	$6.40	3.08%
1,500	$221.68	$228.53	$6.85	3.09%
1,600	$235.69	$243.00	$7.31	3.10%
2,000	$291.75	$300.89	$9.14	3.13%
3,000	$440.66	$454.36	$13.70	3.11%
4,000	$589.57	$607.84	$18.27	3.10%
5,000	$738.48	$761.32	$22.84	3.09%

* 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	
kW		Present Price		Proposed Price			
Load Size	kWh	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase
5	500	$92	$100	$94	$103	2.34%	2.14%
	750	$129	$138	$132	$141	2.50%	2.35%
	1,000	$166	$175	$170	$179	2.60%	2.46%
	1,500	$240	$249	$247	$255	2.69%	2.60%
10	1,000	$166	$175	$170	$179	2.60%	2.46%
	2,000	$314	$323	$323	$332	2.74%	2.67%
	3,000	$463	$471	$476	$484	2.79%	2.74%
	4,000	$593	$601	$610	$619	2.91%	2.86%
20	4,000	$629	$637	$646	$654	2.74%	2.70%
	6,000	$888	$897	$914	$923	2.91%	2.88%
	8,000	$1,148	$1,157	$1,183	$1,192	3.00%	2.98%
	10,000	$1,408	$1,417	$1,451	$1,460	3.06%	3.04%
30	9,000	$1,350	$1,359	$1,389	$1,397	2.87%	2.85%
	12,000	$1,740	$1,749	$1,792	$1,800	2.97%	2.95%
	15,000	$2,130	$2,139	$2,194	$2,203	3.03%	3.02%
	18,000	$2,520	$2,528	$2,597	$2,606	3.07%	3.06%

* 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

		Monthly Billing*				Percent	
kW		Present Price		Proposed Price		Difference	
Load Size	kWh	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase
5	500	$90	$99	$92	$101	2.16%	1.97%
	750	$127	$135	$130	$138	2.31%	2.17%
	1,000	$163	$172	$167	$176	2.39%	2.27%
	1,500	$236	$244	$242	$250	2.48%	2.39%
10	1,000	$163	$172	$167	$176	2.39%	2.27%
	2,000	$308	$317	$316	$325	2.53%	2.46%
	3,000	$454	$462	$465	$474	2.58%	2.53%
	4,000	$581	$590	$597	$605	2.68%	2.64%
20	4,000	$617	$625	$632	$641	2.53%	2.50%
	6,000	$871	$880	$895	$903	2.68%	2.66%
	8,000	$1,126	$1,135	$1,157	$1,166	2.77%	2.75%
	10,000	$1,381	$1,390	$1,420	$1,429	2.82%	2.80%
30	9,000	$1,325	$1,333	$1,360	$1,368	2.65%	2.63%
	12,000	$1,707	$1,715	$1,754	$1,762	2.74%	2.73%
	15,000	$2,089	$2,098	$2,148	$2,156	2.80%	2.79%
	18,000	$2,471	$2,480	$2,541	$2,550	2.84%	2.83%

* 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	Proposed Price	Percent Difference
15	3,000	$428	$441	2.97%
	4,500	$579	$598	3.30%
	7,500	$880	$912	3.62%
31	6,200	$866	$892	3.04%
	9,300	$1,177	$1,216	3.35%
	15,500	$1,799	$1,865	3.66%
40	8,000	$1,112	$1,146	3.05%
	12,000	$1,513	$1,564	3.36%
	20,000	$2,316	$2,401	3.66%
60	12,000	$1,659	$1,710	3.07%
	18,000	$2,262	$2,338	3.38%
	30,000	$3,466	$3,593	3.67%
80	16,000	$2,201	$2,269	3.08%
	24,000	$3,004	$3,106	3.39%
	40,000	$4,610	$4,780	3.68%
100	20,000	$2,743	$2,827	3.09%
	30,000	$3,746	$3,874	3.40%
	50,000	$5,754	$5,966	3.69%
200	40,000	$5,427	$5,597	3.13%
	60,000	$7,435	$7,689	3.42%
	100,000	$11,450	$11,874	3.71%

* 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	$540	$559	3.46%
	6,000	$683	$707	3.65%
	7,500	$825	$856	3.77%
31	9,300	$1,096	$1,135	3.52%
	12,400	$1,391	$1,443	3.70%
	15,500	$1,686	$1,750	3.82%
40	12,000	$1,409	$1,459	3.54%
	16,000	$1,790	$1,856	3.71%
	20,000	$2,170	$2,253	3.83%
60	18,000	$2,106	$2,180	3.55%
	24,000	$2,676	$2,776	3.72%
	30,000	$3,247	$3,371	3.84%
80	24,000	$2,797	$2,897	3.56%
	32,000	$3,558	$3,691	3.73%
	40,000	$4,319	$4,485	3.85%
100	30,000	$3,489	$3,613	3.57%
	40,000	$4,440	$4,606	3.74%
	50,000	$5,391	$5,598	3.85%
200	60,000	$6,925	$7,174	3.60%
	80,000	$8,827	$9,159	3.76%
	100,000	$10,729	$11,145	3.87%

* 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	$3,182	$3,265	2.62%
	30,000	$3,944	$4,069	3.17%
	50,000	$5,467	$5,675	3.81%
200	40,000	$5,921	$6,088	2.81%
	60,000	$7,445	$7,695	3.35%
	100,000	$10,492	$10,908	3.97%
300	60,000	$8,818	$9,068	2.83%
	90,000	$11,103	$11,478	3.37%
	150,000	$15,674	$16,298	3.98%
400	80,000	$11,601	$11,934	2.87%
	120,000	$14,648	$15,148	3.41%
	200,000	$20,742	$21,575	4.01%
500	100,000	$14,417	$14,833	2.89%
	150,000	$18,226	$18,850	3.43%
	250,000	$25,843	$26,883	4.03%
600	120,000	$17,233	$17,732	2.90%
	180,000	$21,803	$22,552	3.44%
	300,000	$30,944	$32,192	4.03%
800	160,000	$22,864	$23,530	2.91%
	240,000	$28,958	$29,956	3.45%
	400,000	$41,146	$42,810	4.05%
1000	200,000	$28,495	$29,327	2.92%
	300,000	$36,112	$37,361	3.46%
	500,000	$51,347	$53,428	4.05%

* 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	$3,897	$4,021	3.20%
	40,000	$4,654	$4,820	3.57%
	50,000	$5,411	$5,618	3.84%
200	60,000	$7,378	$7,627	3.38%
	80,000	$8,892	$9,224	3.73%
	100,000	$10,407	$10,822	3.99%
300	90,000	$11,001	$11,375	3.40%
	120,000	$13,273	$13,771	3.75%
	150,000	$15,545	$16,167	4.01%
400	120,000	$14,552	$15,050	3.42%
	160,000	$17,581	$18,245	3.78%
	200,000	$20,609	$21,440	4.03%
500	150,000	$18,104	$18,727	3.44%
	200,000	$21,890	$22,721	3.79%
	250,000	$25,676	$26,714	4.04%
600	180,000	$21,657	$22,404	3.45%
	240,000	$26,200	$27,196	3.80%
	300,000	$30,743	$31,988	4.05%
800	240,000	$28,762	$29,758	3.46%
	320,000	$34,819	$36,148	3.82%
	400,000	$40,877	$42,537	4.06%
1000	300,000	$35,867	$37,112	3.47%
	400,000	$43,438	$45,099	3.82%
	500,000	$51,010	$53,086	4.07%

* 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	$253	$174	$261	$174	3.25%	0.00%
	3,000	$379	$174	$391	$174	3.25%	0.00%
	5,000	$632	$174	$652	$174	3.25%	0.00%
Three Phase							
20	4,000	$505	$347	$522	$347	3.25%	0.00%
	6,000	$758	$347	$783	$347	3.25%	0.00%
	10,000	$1,263	$347	$1,304	$347	3.25%	0.00%
100	20,000	$2,527	$1,604	$2,609	$1,604	3.25%	0.00%
	30,000	$3,790	$1,604	$3,913	$1,604	3.25%	0.00%
	50,000	$6,317	$1,604	$6,522	$1,604	3.25%	0.00%
300	60,000	$7,581	$3,979	$7,827	$3,979	3.25%	0.00%
	90,000	$11,371	$3,979	$11,740	$3,979	3.25%	0.00%
	150,000	$18,952	$3,979	$19,567	$3,979	3.25%	0.00%

* 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	$373	$172	$384	$172	2.99%	0.00%
	4,000	$497	$172	$512	$172	2.99%	0.00%
	5,000	$622	$172	$640	$172	2.99%	0.00%
Three Phase							
20	6,000	$746	$343	$768	$343	2.99%	0.00%
	8,000	$995	$343	$1,024	$343	2.99%	0.00%
	10,000	$1,243	$343	$1,281	$343	2.99%	0.00%
100	30,000	$3,730	$1,573	$3,842	$1,573	2.99%	0.00%
	40,000	$4,974	$1,573	$5,122	$1,573	2.99%	0.00%
	50,000	$6,217	$1,573	$6,403	$1,573	2.99%	0.00%
300	90,000	$11,191	$3,908	$11,525	$3,908	2.99%	0.00%
	120,000	$14,922	$3,908	$15,367	$3,908	2.99%	0.00%
	150,000	$18,652	$3,908	$19,209	$3,908	2.99%	0.00%

* 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	$35,281	$36,520	3.51%
	500,000	$51,249	$53,315	4.03%
	700,000	$67,218	$70,110	4.30%
2,000	600,000	$69,973	$72,451	3.54%
	1,000,000	$98,300	$102,524	4.30%
	1,400,000	$128,394	$134,308	4.61%
6,000	1,800,000	$192,261	$199,864	3.95%
	3,000,000	$282,545	$295,217	4.48%
	4,200,000	$372,829	$390,570	4.76%
12,000	3,600,000	$382,361	$397,567	3.98%
	6,000,000	$560,149	$585,493	4.52%
	8,400,000	$734,046	$769,528	4.83%

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	$33,529	$34,722	3.56%
	500,000	$49,169	$51,158	4.05%
	700,000	$64,808	$67,594	4.30%
2,000	600,000	$66,479	$68,866	3.59%
	1,000,000	$94,055	$98,123	4.33%
	1,400,000	$123,477	$129,172	4.61%
6,000	1,800,000	$188,082	$195,405	3.89%
	3,000,000	$276,348	$288,553	4.42%
	4,200,000	$364,615	$381,702	4.69%
12,000	3,600,000	$374,034	$388,680	3.92%
	6,000,000	$547,787	$572,197	4.46%
	8,400,000	$717,648	$751,822	4.76%

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	$47,010	$48,913	4.05%
	700,000	$62,104	$64,768	4.29%
2,000	1,000,000	$89,496	$93,388	4.35%
	1,400,000	$117,800	$123,249	4.63%
6,000	3,000,000	$265,920	$277,595	4.39%
	4,200,000	$350,833	$367,179	4.66%
12,000	6,000,000	$526,671	$550,022	4.43%
	8,400,000	$689,825	$722,516	4.74%

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.