ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

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April 1, 2024

VIA ELECTRONIC DELIVERY

Commission Secretary
Idaho Public Utilities Commission
11331 W. Chinden Blvd
Building 8 Suite 201A
Boise, ID 83714

RE: CASE NO. PAC-E-24-05
IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER REQUESTING APPROVAL OF $62.4 MILLION ECAM DEFERRAL

Attention: Commission Secretary

Please find Rocky Mountain Power's Application in the above referenced matter, along with the direct testimony and exhibits of Company witnesses Mr. Jack Painter and Mr. Robert M. Meredith. Mr. Painter's direct testimony and workpapers are confidential and are being sent via an encrypted file. You will receive a separate email to access these files.

Informal inquiries may be directed to Mark Alder, Idaho Regulatory Manager at (801) 220-2313.

Very truly yours,

Joelle Steward
Senior Vice President, Regulation and Customer & Community Solutions

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Attorney for Rocky Mountain Power

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER REQUESTING APPROVAL OF $62.4 MILLION ECAM DEFERRAL	))))	**CASE NO. PAC-E-24-05** **APPLICATION OF ROCKY MOUNTAIN POWER**

Rocky Mountain Power, a division of PacifiCorp ("Company" or "Rocky Mountain Power"), in accordance with Idaho Code §61-502, §61-503, and RP 052*,* hereby respectfully submits this application ("Application") to the Idaho Public Utilities Commission ("Commission") pursuant to the Company's approved energy cost adjustment mechanism ("ECAM"). The Company is requesting approval of approximately $62.4 million of deferred costs from the deferral period beginning January 1, 2023, through December 31, 2023, ("Deferral Period") with a 10.5 percent overall increase to Electric Service Schedule No. 94, Energy Cost Adjustment ("Schedule 94"). In support of its Application, Rocky Mountain Power states as follows:

1. Rocky Mountain Power is a division of PacifiCorp, an Oregon corporation, which provides electric service to retail customers through its Rocky Mountain Power division in the states of Idaho, Wyoming, and Utah. Rocky Mountain Power is a public utility in the state of Idaho and is subject to the Commission's jurisdiction with respect to its prices and terms of electric service to retail customers in Idaho pursuant to Idaho Code §61-129. Rocky Mountain Power is authorized to do business in the state of Idaho providing retail electric service to approximately 88,780 customers in the state.

BACKGROUND

2. The ECAM became effective July 1, 2009, pursuant to an agreement among parties.[1] The ECAM allows the Company to collect or credit the difference between the actual net power costs ("Actual NPC") incurred to serve customers in Idaho and the NPC collected from Idaho customers through rates set in general rate cases ("Base NPC").

3. Included in the ECAM are NPC as defined in the Company's general rate cases and modeled by the Company's Generation and Regulation Initiative Decision ("GRID") production dispatch model.[2] Specifically, NPC includes amounts booked to the following FERC accounts:

- Account 447 (sales for resale, excluding on-system wholesale sales and other revenues not modeled in GRID),
- Account 501 (fuel, steam generation, excluding fuel handling, start-up fuel/gas, diesel fuel, residual disposal and other costs not modeled in GRID),
- Account 503 (steam from other sources),
- Account 547 (fuel, other generation),
- Account 555 (purchased power, excluding BPA residential exchange credit pass-through if applicable), and
- Account 565 (transmission of electricity by others).

4. On a monthly basis, the Company compares the Actual NPC to the Base NPC and defers the difference into the ECAM balancing account. This comparison is on a system-wide, dollar per megawatt-hour basis.[3]

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[1] *In the Matter of the Application of Rocky Mountain Power for Approval of an Energy Cost Adjustment Mechanism (ECAM)*, Case No. PAC-E-08-08, Order No. 30904 (September 29, 2009) ("ECAM Order").
[2] *Id.* at 2-3.
[3] *Id.* at 3.

5. In addition to the difference between Actual NPC and Base NPC, the ECAM includes the following additional components: the Load Change Adjustment Revenues ("LCAR"),[4] coal stripping costs under Emerging Issues Task Force ("EITF") 04-6,[5] Renewable Energy Credit ("REC") revenues,[6] Production Tax Credits ("PTC"),[7] the reasonable energy price ("REP"), as defined in the 2020 Protocol, qualified facility ("QF") costs,[8] and wind availability liquidated damages.[9] These components are described in more detail below.

6. The ECAM includes a symmetrical sharing band of 90 percent (customers) / 10 percent (Company) that shares the differential between Actual NPC and Base NPC, LCAR, and the EITF 04-06 coal stripping costs. The components of the ECAM subject to the sharing band are described in more detail below.

7. PTCs are tracked in the ECAM without applying the sharing band.[10] Under the Internal Revenue Code ("IRC"), a wind facility generates a PTC equal to an inflation-adjusted 1.5 cents per kilowatt hour of electricity produced and sold to a third-party.[11] The PTC is in place for a period of 10 years beginning on the date the facility is placed in-service for income tax purposes.[12] As published in Internal Revenue Service ("IRS") Notice 2023-51, the 2023 PTC rate for electricity generated from qualifying wind facilities placed in service prior to January 1, 2022,

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[4] *Id.* at 4.
[5] *See In the Matter of the Application of PacifiCorp DBA Rocky Mountain Power for Approval of an Accounting Order Authorizing the Deferral of Costs Associated with Coal Mine Stripping Activities,* Case No. PAC-E-09-08, Order No. 30987 (January 22, 2010).
[6] *In the Matter of the Application of PacifiCorp DBA Rocky Mountain Power for Approval of Changes to its Electric Service Schedules,* Case No. PAC-E-10-07, Order No. 32196 at 17 (February 28, 2011).
[7] *In the Matter of PacifiCorp DBA Rocky Mountain Power's Application to Modify the Energy Cost Adjustment Mechanism and Increase Rates*, Case No. PAC-E-15-09, Order No. 33440 at 5 (December 23, 2015) (2015 ECAM Order).
[8] *In the Matter of the Application for Approval of the 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol*, Case No. PAC-E-19-20, Order No. 34640 (April 22, 2020).
[9] *In the Matter of Application of Rocky Mountain Power for Binding Ratemaking Treatment for Wind Reporting,* Case No. PAC-E-17-06, Order No. 33954 at 5 (December 28, 2017).
[10] 2015 ECAM Order at 5.
[11] IRC section 45(a).
[12] IRC section 45(a).

is 2.8 cents per kilowatt hour.[13] The 2023 PTC rate for electricity generated from qualifying wind facilities placed in service after December 31, 2021 is 2.75 cents per kilowatt hour.[14] Additionally, facilities placed in service after December 31, 2022, may also qualify for a 10% bonus credit if the facility is located in a qualified 'energy community.'[15] PTCs are reflected as a reduction to current income tax expense on the financial statements and for ratemaking purposes. A forecasted level of PTCs at the then-current IRC value was included in base rates benefiting customers; however, the quantity and value of PTCs received is dependent on the inflation-adjusted rate effective when they are produced and the amount of generation at eligible facilities. Generation from these facilities is highly dependent on weather, varying from year to year as weather patterns fluctuate. To the extent that actual generation from these facilities varies from the level in base rates, the value of the energy is reflected in Actual NPC and a corresponding adjustment is made to the PTC that customers receive through the ECAM. Facilities that meet IRC qualifications are eligible for PTCs for the first ten years after becoming commercially operational. While many of the Company's wind facilities have reached their ten-year anniversary and would no longer be eligible for PTCs, the repowering program undertaken by the Company has extended this benefit for an additional ten years.

[13] This rate is applicable to all of the Company's credit-eligible wind projects in service as of December 31, 2023, other than Foote Creek II-IV.

[14] Also as published in IRS Notice 2023-51, the 2023 PTC rate for electricity generated from qualifying wind facilities placed in service after December 31, 2021, is .55 cents per kilowatt hour. If the facility (i) has a maximum output of less than 1 megawatt, (ii) began construction prior to January 29, 2023, or (iii) satisfies the prevailing wage and apprenticeship requirements, then the credit amount is multiplied by 5, or 2.75 cents per kilowatt hour. Foote Creek II-IV was placed in service after December 31, 2021, and began construction prior to January 29, 2023, making the applicable 2023 credit rate for this project 2.75 cents per kilowatt hour.

[15] Foote Creek II-IV was placed in service during 2023 and is located in Census Tract Number FIPS Code 56007968100, which is a qualified energy community pursuant to IRS Notice 2023-29, Appendix C. Therefore, the Foote Creek II-IV project qualifies for a 10% bonus credit. The bonus credit is calculated by multiplying standard credit by 10% (e.g., kilowatt hours produced and sold x applicable PTC Rate = Standard Credit).

PROPOSED ECAM RATE

8. In support of this Application, Rocky Mountain Power has filed the testimony and exhibits of Company witnesses Jack Painter and Robert M. Meredith. Mr. Painter's testimony describes the Actual NPC incurred by the Company to serve retail load for the Deferral Period and explains the differences between Actual NPC and Base NPC. Mr. Meredith's testimony describes how the Company's proposed rates were set to recover the 2023 ECAM deferral balances through Electric Service Schedule No. 94 -Energy Cost Adjustment, ("Schedule 94").

9. Exhibit No. 1 to Mr. Painter's testimony illustrates the detailed calculation of the ECAM deferral. The deferral is calculated monthly by comparing Idaho-allocated Actual NPC to the Base NPC collected in rates that was established in the Company's most recent rate case, ("2021 Rate Case").[16] For the Deferral Period the NPC differential was approximately $65.9 million before the 90/10 percent sharing band. Mr. Painter's testimony explains the main drivers for the net power cost deferral, which include increased power market prices, coal supply constraints, and decreased hydro generation from the amounts forecasted from the 2021 Rate Case.

10. Mr. Painter's testimony specifically addresses the LCAR, EITF 04-6 treatment of coal stripping costs, a true-up of 100 percent of the incremental REC revenues, PTCs, the REP QF charge, and wind availability liquated damages.

11. The LCAR is a symmetrical adjustment to offset over- or under-collection of the Company's energy-related production revenue requirement, excluding NPC, due to variances in Idaho load. The LCAR increased the deferral balance by approximately $268,994 before applying the sharing band due to higher usage during the Deferral Period.

[16] *In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Rates and Charges in Idaho and Approval of Proposed Electric Service Schedules and Regulations*. Case No. PAC-E-21-07. The test period for this case was based on a historical twelve-month period ending December 31, 2020, with adjustments made for known and measurable changes through December 31, 2021.

12. The difference between including coal stripping costs recorded on the Company's books under the guidance of the accounting pronouncement EITF 04-6, and expensing coal stripping costs when the coal was excavated increased the ECAM deferral by $60,594 before applying the sharing band.

13. The total NPC deferral adjusted for LCAR and EITF 04-6 was approximately $66.2 million for which customers are responsible 90 percent, and the Company is responsible for the remaining 10 percent. After accounting for the sharing band, the NPC deferral is approximately $59.6 million.

14. During the Deferral Period the PTC differential, as described in paragraph 7, increased the deferral approximately $900 thousand.

15. The ECAM also tracks the difference between actual REC revenues during the Deferral Period and the amount of REC revenues credited to customers in base rates. The REC revenue true-up included in the ECAM is symmetrical, but no sharing band is applied. During the Deferral Period actual REC revenue was $357,308 higher than the amount credited to customers in base rates on an Idaho-allocated basis.

16. In accordance with Order No. 33954, wind availability liquidated damages were credited to customers in the amount of $310,085.

17. Interest is accrued on the uncollected balance at the Commission-approved interest rate for customer deposits. During the Deferral Period the interest rate was 2.0 percent. Interest of $1.2 million was added to the ECAM balance.

18. The ECAM balance at the end of the Deferral Period was $75.4 million, including $62.4 million from the 2023 ECAM deferral (inclusive of interest), plus $13.0 million remaining balance from prior ECAM filing. The Company estimates the ECAM balance will be reduced by

$10.5 million from Schedule 94 revenue collections accrued from January 1 through May 31, 2024, resulting in an estimated ECAM balance of $64.9 to be collected.

19. Mr. Meredith's testimony describes how Schedule 94 rates were designed to recover the May 31, 2024, estimated ECAM balance of $64.9. Based on this rate design, the Company proposes Schedule 94 rates of 1.878, 1.844, 1.782, and 1.798 cents per kWh for secondary, primary, transmission delivery service voltages and Schedule 400, respectively.

COMMUNICATIONS

Communications regarding this filing should be addressed to:

Mark Alder
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Senior Attorney
Rocky Mountain Power
825 NE Multnomah, Suite 2000
Portland, OR 97232
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In addition, Rocky Mountain Power requests that all data requests regarding this Application be sent in Microsoft Word to the following:

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

Informal questions may be directed to Mark Alder, Idaho Regulatory Affairs Manager at (801) 220-2313.

Included with this Application is a copy of the press release, which will be issued on April 1, 2024. Additionally, this Application includes a copy of the customer notice, which will be included with customers' bills beginning April 3, 2024, and will run for a full billing cycle.

REQUEST FOR RELIEF

The ECAM allows the Company to collect or credit the difference between the Actual NPC incurred to serve customers in Idaho and the Base NPC collected through base rates assuring customers pay the actual NPC after sharing. To the best of the Company's knowledge the ECAM deferral has been accurately calculated incorporating all associated Commission Orders in this Application.

WHEREFORE, Rocky Mountain Power respectfully requests that the Commission issue an order: (1) authorizing that this matter be processed by Modified Procedure; (2) approving approximately $62.4 million ECAM deferral; and (3) approving a 10.5 percent increase to Electric Service Schedule No. 94, Energy Cost Adjustment effective June 1, 2024.

DATED this 1st day of April 2024.

Respectfully submitted,

ROCKY MOUNTAIN POWER

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Attorney for Rocky Mountain Power

CUSTOMER NOTICES

Annual energy cost adjustment

Proposed net price increase

Rocky Mountain Power requests recovery of power costs

On April 1, 2024, Rocky Mountain Power asked the Idaho Public Utilities Commission to approve the incremental energy related costs for 2023 of $64.9 million, a net increase of $32.6 million from the revenues currently collected through the energy cost adjustment mechanism. The energy cost adjustment mechanism is designed to track the difference between the company's actual expenses for fuel and electricity purchased from the wholesale market, against the amount being collected from customers through current rates.

Pending commission approval, the increase would take effect June 1, 2024. All customer classes will see a net increase to their rates due to the increased costs for fuel and wholesale electricity. Extreme weather conditions in 2023 increased the costs of fuel and purchased power on the wholesale market — two of the main components of the company's annual power cost adjustment. Additionally, coal supply restrictions that began in late 2022 continued into 2023 – due to several factors, including a fire at a major coal mine and higher exports of U.S. coal to Europe – while natural gas prices soared. These factors caused significant price increases for the resources Rocky Mountain Power must purchase for power generation to meet demand and balance its system.

Increases in wholesale power prices account for nearly half of the total cost adjustment requested. The proposed adjustment will allow Rocky Mountain Power to continue to deliver safe, reliable, low-cost power now and for years to come while navigating a time of volatile energy markets.

A typical residential customer using 783 kilowatt-hours per month would see an increase of approximately $7.39 a month on their electricity bill. The following is a summary of the percentage impacts by customer class:

- **Residential Schedule 1** – 7.6% increase
- **Residential Schedule 36** –8.7% increase
- **General Service Schedule 6** –10.7% increase
- **General Service Schedule 9** –13.1% increase
- **Irrigation Service Schedule 10** –9.5% increase
- **General Service Schedule 23** –9.0% increase
- **General Service Schedule 35** –10.3% increase
- **Public Street Lighting** –5.2% increase
- **Tariff Contract 400** –13.5% increase

We understand the impact that price increases have on our customers and that a price increase is never welcome news. We will work to mitigate that impact as much as possible. Customers can visit RockyMountainPower.net/Wattsmart for energy and money-saving tips and information.

The public will have an opportunity to comment on the proposal during the coming months as the commission studies the company's request. The commission must approve the proposed changes before they can take effect.

A copy of the company's application is available for public review on the commission's website at **www.puc.idaho.gov under Case No. PAC-E-24-05**.

Customers may file written comments regarding the application with the commission or subscribe to the commission's RSS feed to receive periodic updates via email about the case. Copies of the proposal are also available for review at the company's offices in Rexburg, Preston, Shelley, and Montpelier, although the company encourages customers to visit our website at RockyMountainPower.net/Rates.

Idaho Public Utilities Commission
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For more information about your rates and rate schedule, go to **RockyMountainPower.net/Rates**.

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Annual energy cost adjustment

Higher fuel costs and severe weather prompt price increase request for Idaho customers of Rocky Mountain Power

BOISE, Idaho (April 1, 2024) — Rocky Mountain Power's costs for fuel and wholesale electricity increased in 2023 because of coal supply disruptions and severe weather, which made purchased power to serve its customers more expensive. As part of an annual review of these costs, the company requested an average 10.5% price increase for Idaho customers. A typical residential customer using 783 kilowatt-hours per month would see a 7.6% increase, or $7.39 per month on their electricity bill. The increase will take effect June 1, 2024, subject to review by the Idaho Public Utilities Commission.

"We recognize that in difficult economic conditions, a price increase is not good news," said David Eskelsen, spokesman for Rocky Mountain Power. "Despite these difficulties, we remain committed to bringing the best value to our customers for their hard-earned dollars. We've worked diligently to control the costs we can control. We are strict with our budgets and continue our work to steadily improve our system to enhance reliability for our 89,163 customers in southeastern Idaho. We know how important reliable service is for businesses and homes alike.

"The company is working hard to maintain our position as a low-cost energy provider," Eskelsen added. "The annual adjustment process makes sure Rocky Mountain Power customers always pay a fair price for the energy they need."

The most significant driver in this year's energy cost adjustment involves coal supply and inventory restrictions that began in late 2022 and continued into 2023. Historically low coal inventories and soaring natural gas prices prompted many utilities, including Rocky Mountain Power, to increase coal purchases for generation and to restock depleted coal inventories. In many coal basins nationally, coal pricing more than doubled in 2022 and remained high into 2023. This effect on coal pricing was made worse 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.

"Due to overall lower coal resource output, the company had to adjust its overall system operations through increased natural gas power plant output, reduced market sales and increased market purchases," said Jack Painter, net power cost specialist for the utility. "In 2023, all of PacifiCorp's Utah coal suppliers and one major Wyoming coal supplier made emergency contract declarations that resulted in significant delivery shortfalls of PacifiCorp's contracted coal supply. Consequently, the Utah coal mines experienced a 35% decrease in coal production."

These challenges included a coal mine fire that occurred at American Consolidated Natural Resources' Lila Canyon mine in central Utah. The mine had produced more than 25% of Utah's coal production in recent years. The mine first stopped production in September 2022 and the owners 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 response, the company explored the purchase of reasonably priced coal from a variety of other sources, as well as using surplus coal reserves held by the company.

The annual energy cost adjustment mechanism is designed to track the difference between the company's actual expenses for fuel and electricity purchased from the wholesale market, against the amount being collected from customers through current rates. Pending commission approval, the changes would take effect June 1, 2024, with the following impact on each rate schedule:

Residential Schedule 1 – 7.6% increase
Residential Schedule 36 – 8.7% increase
General Service Schedule 6 – 10.7% increase
General Service Schedule 9 – 13.1% increase
Irrigation Service Schedule 10 – 9.5% increase
General Service Schedule 23 – 9.0% increase
General Service Schedule 35 – 10.3% increase
Public Street Lighting – 5.2% increase
Tariff Contract 400 – 13.5% increase

The public will have an opportunity to comment on the proposal as the commission studies the company's request. The commission must approve the proposed changes before they can take effect. A copy of the company's application is available for public review on the commission's website, www.puc.idaho.gov, under Case No. PAC-E-24-05. Customers may also subscribe to the commission's RSS feed to receive periodic updates via email. The request is required to be available at the company's offices in Rexburg, Preston, Shelley and Montpelier, although the company urges customers to visit our website at rockymountainpower.net/rates.

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Montpelier – 24852 U.S. Hwy 89

# # #

About Rocky Mountain Power
Rocky Mountain Power provides safe and reliable electric service to more than 1.2 million customers in Utah, Wyoming and Idaho. The company supplies customers with electricity from a diverse portfolio of generating plants including hydroelectric, thermal, wind, geothermal and solar resources. Rocky Mountain Power is part of PacifiCorp, one of the lowest-cost electricity providers in the United States, with 2 million customers in six western states. For more information, visit: www.rockymountainpower.net

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER REQUESTING APPROVAL OF $62.4 MILLION ECAM DEFERRAL	)))))	**CASE NO. PAC-E-24-05** **DIRECT TESTIMONY OF JACK PAINTER REDACTED**

ROCKY MOUNTAIN POWER

CASE NO. PAC-E-24-05

April 2024

Q. Please state your name, business address, and present position with PacifiCorp d/b/a Rocky Mountain Power ("Rocky Mountain Power" or the "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.

QUALIFICATIONS

Q. Please 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 Idaho, Utah, Wyoming, Oregon, Washington, and California.

PURPOSE OF TESTIMONY

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

A. My testimony presents and supports the Company's calculation of the Energy Cost Adjustment Mechanism ("ECAM") balancing account for the 12-month period of January 1, 2023 through December 31, 2023 ("Deferral Period"). More specifically, I provide the following:

- A summary of the ECAM calculation, including changes made to comply with Idaho Public Utility Commission ("Commission") orders;
- Details supporting the addition of approximately $62.4 million to the deferral

balance, including $59.6 million customers' share of ECAM costs, a $900 thousand decrease in renewable energy production tax credits ("PTCs"), $1.5 million in reasonable energy price ("REP") qualified facility ("QF") costs, a credit of $310 thousand for wind availability liquidated damages, a $357 thousand renewable energy credit ("REC") revenue differential, and $1.2 million interest accrued;

- Discussion of the main differences between adjusted actual net power costs ("Actual NPC") and net power costs in rates ("Base NPC"); and
- Discussion about the Company's participation in the Western Energy Imbalance Market ("WEIM") with the California Independent System Operator ("CAISO") and the benefits from the WEIM that are passed through to customers.

Q. What other witnesses present testimony for the ECAM and Tariff Schedule 94 in this case?

A. Mr. Robert M. Meredith, Director, Pricing & Tariff Policy, provides testimony on the proposed rates in Electric Service Schedule No. 94, Energy Cost Adjustment ("Schedule 94").

SUMMARY OF THE ECAM DEFERRAL CALCULATION

Q. Please briefly describe the Company's ECAM authorized by the Commission.

A. The ECAM tracks deviations between Actual NPC and Base NPC. When there is a difference between these two amounts, 90 percent of the difference is deferred for later recovery or return to customers.[1] In addition to tracking the difference between Actual

[1] *See* Order No. 30904 in Case No. PAC-E-08-08 and Order No. 33440 in Case No. PAC-E-15-09.

and Base NPC, the ECAM also tracks other items including PTCs, the Reasonable Energy Price QF adjustment, wind availability liquidated damages, and revenues from the sale of RECs.[2] The purpose for tracking these items is to true-up base rates to actuals. The balance that accumulates over a deferral period is then passed on to customers as a rate surcharge or credit. Schedule 94, described in Mr. Meredith's testimony, appears as a separate line item on customers' bills and either collects from or credits to customers the balance of deferred costs. Schedule 94 is adjusted as needed in the Company's annual ECAM filings.

The Company is required to file an application with the Commission annually by April 1st to request approval of the deferral amount and the new Schedule 94 rates to become effective June 1.

Q. Are there any changes to the ECAM calculation?

A. No. The rates for Base NPC, PTCs, RECs, and the Load Change Adjustment Revenue ("LCAR") were established in the Company's last general rate case ("GRC") Case No. PAC-E-21-07, which became effective January 1, 2022 and are the same rates used in the previous ECAM Case No. PAC-E-23-09.[3] Changes in the previous ECAM included the removal of wind integration costs for third party wind because PacifiCorp's Open Access Transmission Tariff ("OATT") Schedule 3 and 3A rates include intra-hour wind integration costs and offset Base rates in FERC Account 456, liquidated damages for wind availability were included and are passed to customers outside of the sharing

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[2] *See In the Matter of PacifiCorp DBA Rocky Mountain Power's Application to Modify the Energy Cost Adjustment Mechanism and Increase Rates*, Case No. PAC-E-15-09, Order No. 33440 at 5–6 (December 23, 2015).

[3] *In the Matter of Rocky Mountain Power's Application for Authority to Increase its Rates and Charges in Idaho and Approval of Proposed Electric Service Schedules and Regulations,* Case No. PAC-E-21-07, Order No. 35277 (December 30, 2021).

band, and both the Resource Tracking Mechanism ("RTM") and the Lake Side 2 Resource Adder were eliminated as part of the Company's last GRC.

ECAM DEFERRAL CALCULATION

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

A. Table 1 summarizes the total ECAM deferral and provides a breakdown of the individual components of the ECAM. For a detailed monthly calculation of the ECAM deferral, please refer to Exhibit No. 1.

Table 1 – 2023 ECAM Deferral

Calendar Year 2023 ECAM Deferral		
NPC Differential	$	65,874,728
EITF 04-6 Adjustment		60,594
LCAR		268,994
Total Deferral Before Sharing	$	66,204,316
Sharing Band		90%
Customer Reponsibility	$	59,583,884
Production Tax Credits	$	907,177
REP QF Adjustment		1,450,130
Wind Liquidated Damages		(310,085)
REC Deferral		(357,308)
Interest on Deferral		1,157,387
Annual Deferral (Jan - Dec 2023)	$	62,431,185

The first section of Table 1 summarizes the Idaho-allocated share of those items for which Idaho customers and the Company share responsibility, including: NPC differential, Emerging Issues Task Force ("EITF") 04-6 adjustment, and the LCAR costs. The second section calculates the 90 percent customers' share of these items. Finally, the last section adds the following items that are either refunded or collected in full (i.e., 100 percent): PTCs, REP QF costs, wind availability liquidated damages, REC revenues, and interest on the deferral. The total of these items represents the ECAM deferral.

Q. Based on your calculations, what is the balance expected to be in the ECAM deferral account as of June 1, 2024?

A. Table 2 provides a summary of the ECAM balancing account activity starting with the December 31, 2022, ECAM deferral balance of $41.9 million approved in Case No. PAC-E-23-09. By June 1, 2024, the projected balance in the ECAM deferral account will be approximately $64.9 million. During the Deferral Period, approximately $62.4 million is added to the balance from the annual deferral and interest, which is offset by $29.0 million of ECAM revenue collections through the Deferral Period, and an estimated collection of $10.5 million of Schedule 94 revenues, net of interest, between January and May of 2024.

Table 2 - Balancing Account Activity

ECAM Deferral Balance		
Deferral Balance - Dec 31, 2022	$	41,941,478
Annual Deferral (Jan - Dec 2023)		61,273,798
Interest		1,157,387
ECAM Revenue Collection - Schedule 94		(28,953,155)
December 31, 2023 Balance For Collection	$	75,419,507
Schedule 94 Collection - Jan - May 2024	$	(11,971,685)
Interest		1,459,118
Expected Balance as of June 1, 2024	**$**	**64,906,940**

Q. Please describe the ECAM calculations in Exhibit No. 1.

A. The ECAM deferral is calculated monthly by comparing Idaho-allocated Actual NPC to the Base NPC collected in rates, and then deferring the differences into an ECAM balancing account. Exhibit No. 1 includes details of the ECAM calculation. Additionally, I have also provided confidential work papers supporting this exhibit.

Q. How are the Base NPC and Actual NPC calculated?

A. Exhibit No. 1 provides details of the ECAM calculation. The monthly Base NPC collected in rates, as set forth in Exhibit No. 1 line 6, is calculated by taking the dollar-per-megawatt-hour Base NPC rate multiplied by the actual Idaho retail sales. The Actual Idaho NPC, as set forth in Exhibit No. 1 line 11, is calculated by dividing the monthly total Company Actual NPC in the Deferral Period by the actual monthly system megawatt-hours ("MWh") in the Deferral Period. To calculate Actual Idaho NPC, the total Company Actual NPC dollar-per-megawatt-hour basis is then multiplied by Idaho actual monthly MWh.

Q. Please describe how the NPC deferral is calculated.

A. The deferral is calculated monthly by subtracting the Base NPC collected in rates from the Actual Idaho NPC. For the Deferral Period, the NPC differential was $65.9 million before applying the 90/10 percent sharing band.

Q. What costs are included in the NPC differential for deferral?

A. The NPC differential for deferral captures all components of NPC as defined in the Company's general rate case proceedings and modeled by the Company's production dispatch model, the Generation and Regulation Initiative Decision Tool ("GRID"). Specifically, Base NPC and Actual NPC include 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 GRID

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 GRID

Account 503 – Steam from other sources

Account 547 – Fuel, other generation

Account 555 – Purchased power; excluding the Bonneville Power Administration ("BPA") residential exchange credit pass-through if applicable

Account 565 – Transmission of electricity by others

Q. Are adjustments made to the Actual NPC before comparing them to Base NPC?

A. Yes. The Company 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 ECAM on July 1, 2009;
- 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 and Utah;
- coal inventory adjustments to reflect coal costs in the correct period;
- legal fees related to fines and citations included in the cost of coal;
- wind availability liquidated damages; and
- reasonable energy price adjustments to QFs.

Q. Why is the July 1, 2009, cutoff used to determine out of period entries?

A. Since the ECAM took effect, customers' rates have been adjusted to recover essentially all of the Company's actual net power costs, excluding any differences due to the 90/10 percent sharing band. Consequently, any accounting entries made during the current

Deferral Period that relate to any operating period since the ECAM took effect should be reflected in customer rates, whether they increase or decrease Actual NPC. However, accounting entries related to operating periods before the inception of the ECAM should not impact the ECAM deferral.

Q. In addition to comparing Actual NPC to Base NPC, what other components are included in the ECAM?

A. The ECAM calculation includes six additional components: (i) an adjustment for deferred costs associated with coal mine stripping activities recorded under the Financial Accounting Standards Board ("FASB") EITF 04-6; (ii) the LCAR adjustment; (iii) a true-up of PTCs; (iv) Idaho allocated REP QF costs; (v) wind availability liquidated damages; and (vi) a true-up of REC revenues as authorized in Order No. 32196.

Q. How is the adjustment for accounting pronouncement EITF 04-6 included in the ECAM?

A. Line 13 of Exhibit No. 1 calculates coal stripping costs, reflecting Idaho's allocated differences between the coal stripping costs incurred by the Company during excavation, as recorded on the Company's books pursuant to the guidance of the accounting pronouncement EITF 04-6, and the amortization of the coal stripping costs as approved by the Commission in Case No. PAC-E-09-08, Order No. 30987. During the Deferral Period, the total EITF 04-6 coal stripping deferral adjustment results in a $61 thousand increase to the ECAM deferral balance, before the application of the 90/10 percent sharing band.

Q. Please describe the LCAR adjustment.

A. The calculation of the LCAR adjustment is a symmetrical adjustment for over- or under-collection of the energy-related portion of the Company's embedded revenue requirement for production facilities, as specified in Case No. GNR-E-10-03, Order No. 32206. This adjustment accounts for variances in Idaho load that cause the Company to collect more or less of these production-related costs. The LCAR rate of $8.74 per MWh is used for the Deferral Period.

Q. How is the LCAR adjustment calculated and what impact does it have on the Deferral Period?

A. The LCAR adjustment assumes that the actual production-related costs of the LCAR are equivalent to the base amount on Exhibit No. 1 line 14. The actual production-related costs are then compared to the LCAR revenue collection in rates, calculated by multiplying the LCAR rate by the actual Idaho retail sales on Exhibit No. 1 line 17. The LCAR adjustment, which is shown on line 18 of Exhibit No. 1, is the difference between the actual production-related costs and the LCAR revenue. This adjustment results in a $300 thousand increase to the ECAM deferral balance before application of the 90/10 percent sharing band.

Q. Please explain the sharing band ratio between the Company and customers in the ECAM.

A. The ECAM includes a sharing band with a symmetrical sharing ratio in which customers either pay or receive 90 percent of the ECAM deferral balance, and the Company is responsible for the remaining 10 percent. Line 20 of Exhibit No. 1 represents the customers' 90 percent share of the monthly deferral shown on line 19.

For the Deferral Period, the customers' share of the deferred balance is $59.6 million. The remaining balance of $6.6 million associated with the Company's 10 percent share is not included in the deferral balance as it is not recoverable from customers.

Q. What is the amount of the PTC true-up in the current filing?

A. The PTC Deferral, on line 25 of Exhibit No. 1, is calculated by comparing the actual Idaho-allocated PTC to the PTC credit customers receive through base rates. The PTC credit in base rates is calculated by multiplying the approved PTC rate of $4.16/MWh by Idaho retail sales. The difference results in a $900 thousand increase to the ECAM deferral.

Q. Please explain the REP QF Adjustment.

A. As set forth in the 2020 Inter-Jurisdictional Allocation Protocol ("2020 Protocol"): "For the Interim Period, the energy output of New QF PPAs will be dynamically allocated per this agreement using the SG Factor, priced at a forecasted reasonable energy price defined below, and any cost of a New QF PPA above the forecasted reasonable energy price will be situs assigned to and allocated to the State of Origin." [4] The Idaho situs-assigned cost, on line 26 of Exhibit No. 1, is $1.5 million.

Q. Please explain the wind availability liquidated damages credit?

A. Order No. 33954 in Case No. PAC-E-17-06 provides that "the Stipulation requires the Company to pass on to ratepayers all liquidated damages it receives from equipment suppliers in case the repowered equipment does not meet specified availability, performance, or installation schedule requirements." The Company first removes the wind availability liquidated damages from total-Company NPC and then allocates them

[4] *In the Matter of the Application for Approval of the 2020 PacifiCorp-Interjurisdictional Allocation Protocol,* Case No. PAC-E-19-20, Order No. 34640 at § 4.4.2.1, 31 (April 22, 2020).

to customers using the System Generation ("SG") allocation factor outside of the 90/10 percent sharing band. The wind availability liquidated damages credited to customers in the ECAM is $310 thousand, as shown on line 27 of Exhibit No. 1.

Q. What is the amount of REC revenue adjustment in the current filing?

A. The REC revenue adjustment shown on line 32 of Exhibit No. 1 is calculated by comparing the actual Idaho-allocated REC revenue with the REC revenue credit customers receive through base rates. The REC revenue credit in base rates is calculated by multiplying the approved REC revenue rate of $0.07/MWh by Idaho retail sales. The resulting difference is a $357 thousand decrease to the ECAM deferral.

Q. What is the total ECAM deferred balance calculated in Exhibit No. 1?

A. The total ECAM deferred balance as of December 31, 2023, is $61.3 million, shown on line 33 of Exhibit No. 1, plus $1.2 million of interest on line 42, for a total deferral of $62.4 million.

Q. Does the calculation of the ECAM deferral in this application comply with the parameters of the Idaho ECAM as approved by the Commission?

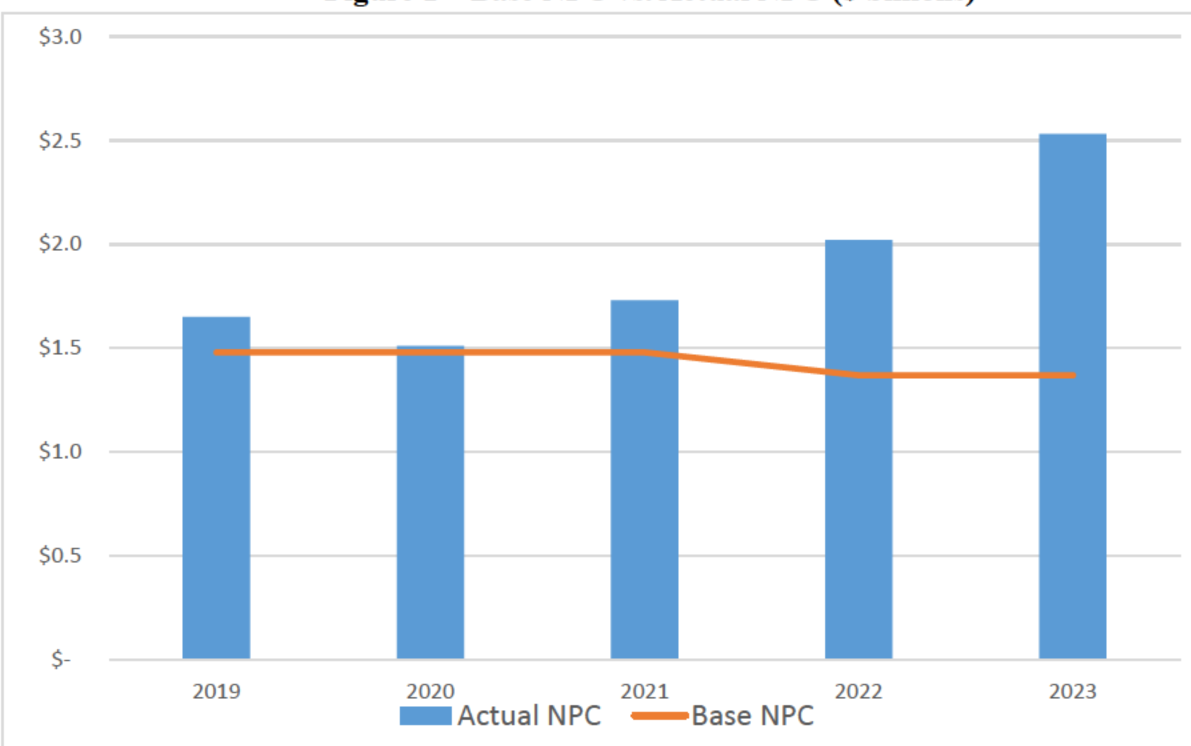
A. Yes, therefore the Company recommends that the Commission approve the ECAM application for recovery of the $62.4 million in prudently incurred ECAM costs.

DIFFERENCES IN NPC

Q. Please describe the Base NPC the Company used to calculate the NPC component of the ECAM deferral.

A. The total-Company Base NPC of $1.368 billion were set in Case No. PAC-E-21-07 ("2021 Rate Case") using a 12-month test period of January 2021 through December 2021 and became effective January 1, 2022. Based upon a normalized forecast and perfect operating conditions, circumstances have changed significantly since the Base NPC were established. Both higher market power and natural gas prices, shifts from base load resources to intermittent renewable energy resources, coal fuel supply constraints, extreme weather events, and drought have all contributed to current system operations that do not represent the forecast. The Company operates its system on a least cost economic dispatch model for its customers and it is important to note that Base NPC are set for ratemaking purposes only, not the management of actual system operations, nor would it be prudent to do so. Figure 1 below illustrates how Base NPC have been fairly static over time, while Actual NPC has increased significantly.

Figure 1 – Base NPC vs. Actual NPC ($ billions)



Q. On a total-Company basis, what was the difference between Actual NPC and Base NPC for the Deferral Period?

A. On a total-Company basis, Actual NPC for the Deferral Period amounted to $2.534 billion, exceeding Base NPC for the Deferral Period by $1.166 billion. Table 3 provides a high-level summary of the difference between Base NPC and Actual NPC by category on a total-Company basis.

Table 3 - Net Power Cost Reconciliation ($ millions)

		TOTAL
Base NPC	$	1,368
Increase/(Decrease) to NPC:		
Wholesale Sales Revenue		290
Purchased Power Expense		577
Coal Fuel Expense		(43)
Natural Gas Expense		328
Wheeling and Other Expense		14
Total Increase/(Decrease)	$	1,166
Adjusted Actual NPC	$	2,534

Q. Please describe the primary differences between Actual NPC and Base NPC.

A. From an accounting perspective, and as shown in Table 3, Actual NPC were higher than Base NPC, established in the 2021 Rate Case, due to a $290 million reduction in wholesale sales, a $577 million increase in purchased power expense, a $328 million increase in natural gas expense, and a $14 million increase in wheeling and other expenses. These items were partially offset by a $43 million reduction in coal fuel expense.

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

A. For 2023, two main drivers increased NPC, coal fuel supply constraints and increased market power and natural gas prices, both of which are discussed with further detail in my testimony below. Coal supply constraints which began at the end of calendar year 2022, continued through 2023 and still impact the Company today. Market power prices and natural gas prices have risen sharply since 2021. These drivers have an overarching influence on all components of the Company's actual system operations through its least cost economic dispatch model. Some of the more significant changes identified in 2023 are reduced wholesale sales volumes, reduced coal generation volumes, and increased gas generation volumes.

Q. Please explain the changes in wholesale sales revenue and volumes.

A. Wholesale sales volumes declined relative to Base NPC due to an increase in total Company load combined with coal supply constraints and decreases in renewable resource output and hydro generation. 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. Additionally, as market power prices and loads increase simultaneously, wholesale sales volumes decrease as the Company serves its load through its own generation. Overall, the above market and system dynamics, decreased wholesale sales revenue by $290 million compared to Base NPC. While the average price of actual market sales transactions was $67.43/MWh, or 56 percent higher than the average price in Base NPC, actual wholesale market volumes were 8,178 gigawatt-hours ("GWh"), or 76 percent, lower than Base NPC. In order to achieve a more accurate level of wholesale sales volumes, the Company will be proposing enhancements to its power cost modeling in the upcoming general rate case.

Q. Please explain the changes in purchased power expense.

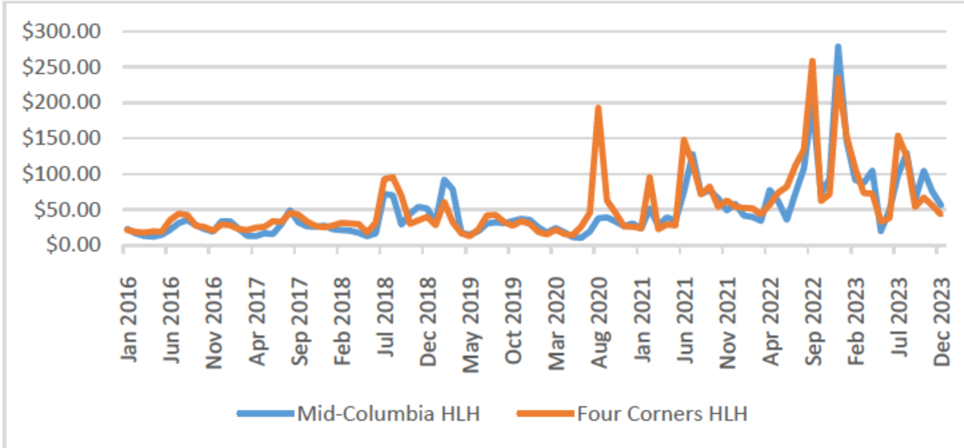
A. Overall, actual purchased power expense increased $577 million over Base NPC because the actual average price from market purchase transactions, represented in the power cost production model as short-term firm and system balancing purchases, significantly increased. On a dollar per megawatt-hour basis, actual market purchase transactions increased from $35.77/MWh in Base NPC to $116.40/MWh, or 225 percent, but were slightly offset by the lower actual market purchase volume of 146 GWh which was two percent lower than Base NPC.

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 4 and Figure 2 illustrate these significant market price increases impacting 2023 NPC.

Table 4 – 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 and volumes.

A. As discussed in my testimony above and as explained in great detail in the Company's 2022 ECAM Confidential Investigative Report submitted to the Commission in Case No. PAC-E-23-09 on December 22, 2023, 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. Due to overall lower coal fuel availability, the Company had to adjust its overall system operations through increased natural gas resource output and reduced wholesale sales. Total coal fuel expense decreased because coal generation volume was 7,924 GWh, or 27 percent lower than Base NPC as presented in Table 5.

Table 5 – Coal Generation

Year	Base GWh	Actual GWh	Variance	Percent
2020 ECAM	39,100	30,635	(8,465)	(22%)
2021 ECAM	39,100	31,590	(7,510)	(19%)
2022 ECAM	29,875	28,391	(1,484)	(5%)
2023 ECAM	29,875	21,951	(7,924)	(27%)

The coal supply shortages also increased the average cost of coal generation from $20.08/MWh in Base NPC to $25.39/MWh in the Deferral Period. Overall the lower generation volume results in a decrease of $43 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 explain 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. While natural gas prices and the average cost of natural gas generation are higher than Base NPC, the price for operating the Company's natural gas generating resources was more economic than market power purchases on average. Overall, the total natural gas fuel expense in Actual NPC increased by $328 million compared to Base NPC. This was due to both an increase in the average cost of natural gas generation from $26.95/MWh in Base NPC to $39.61/MWh in the Deferral period and an increase in gas generation volumes of 5,562 GWh (66 percent) as shown in Table 6 below.

Table 6 – Natural Gas Generation

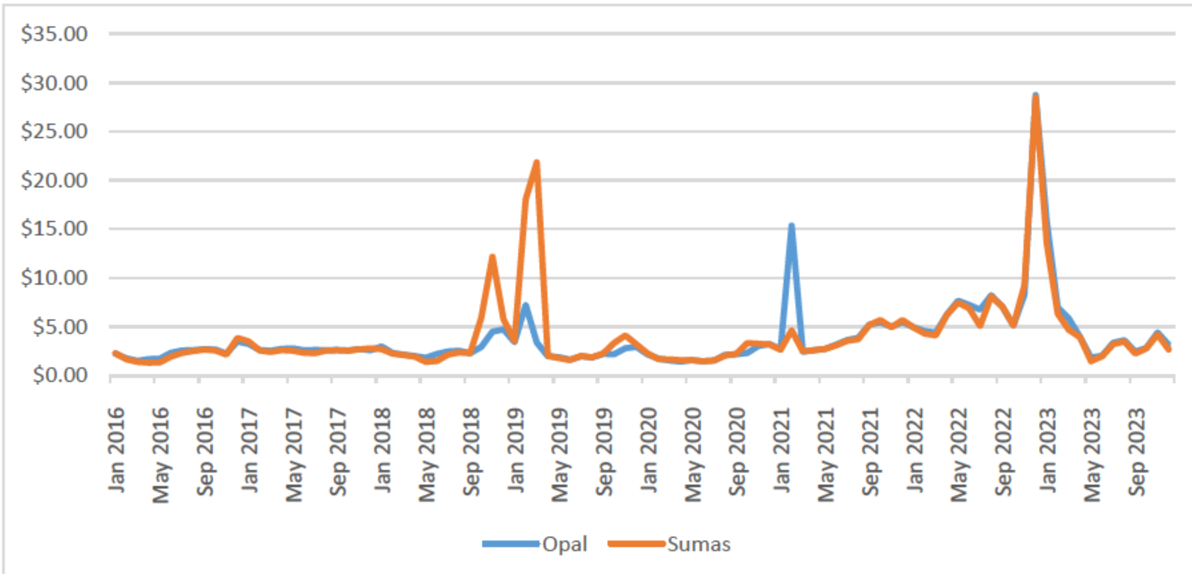
Year	Base GWh	Actual GWh	Variance	Percent
2020 ECAM	12,349	12,042	(307)	(2%)
2021 ECAM	12,349	13,312	963	8%
2022 ECAM	8,488	13,686	5,198	61%
2023 ECAM	8,488	14,050	5,562	66%

Like the significant increase in the average price of market power purchases discussed above, average natural gas prices have also seen a significant increase during the same timeframe. Table 7 and Figure 3 below illustrate these increases impacting 2023 NPC.

Table 7 – 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 1,441 GWh (32 percent) lower than forecasted generation from the 2021 Rate Case as shown in Table 8 below and needed to be replaced to meet customer demand.

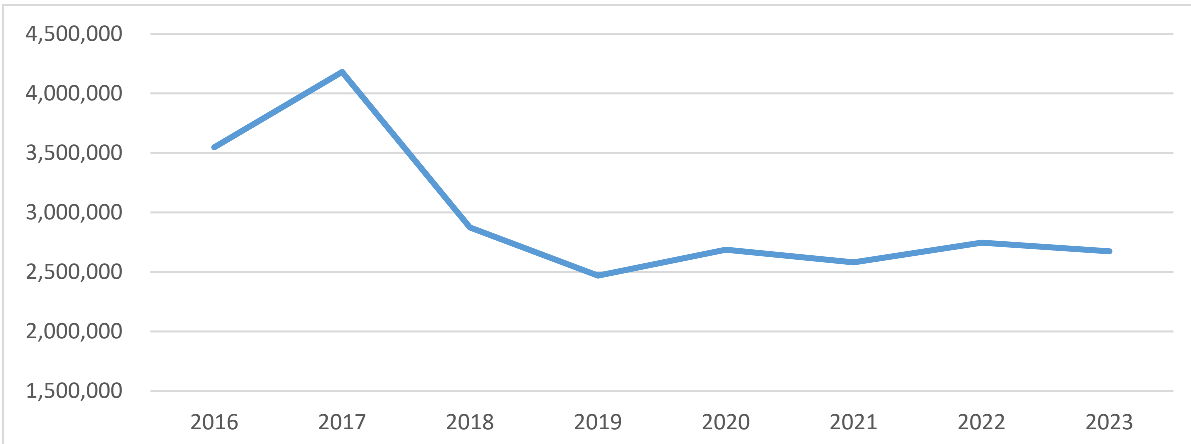
Table 8 – Hydro Generation

Year	Base GWh	Actual GWh	Variance	Percent
2020 ECAM	3,812	3,037	(775)	(20%)
2021 ECAM	3,812	2,789	(1,023)	(27%)
2022 ECAM	4,441	2,936	(1,505)	(34%)
2023 ECAM	4,441	3,000	(1,441)	(32%)

The estimated impact on total-Company NPC in 2023 due to decreased hydro MWhs caused by drought is $123 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 9 and Table 10 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 9 – Opal and Sumas Average Monthly Price ($/MMBtu)

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

Table 10 – 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

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 11 below highlights recent Utah coal market production data.

Table 11

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 ("NARM") 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 mine 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.

COMPLIANCE COSTS

Q. Has there been any additional purchase requirements for NPC in 2023 for the Company to operate its system and resources?

A. Yes. The Company had to acquire allowances for the Washington Climate Commitment Act ("CCA"), which caps and reduces greenhouse gas emissions in Washington. Additionally, the Ozone Transport Rule ("OTR"), which is the federal plan for interstate transport of the 2015 ozone National Ambient Air Quality Standards was planned to become effective on August 4, 2023.

Q. Does the Company have to comply with the Washington CCA to operate its Chehalis natural gas generating plant?

A. Yes. The Washington CCA requires the Company to purchase allowances for output at its Chehalis natural gas generating facility. In 2023, the Company made $42 million in purchases, on a total-company basis, to comply with the Washington CCA. These costs were necessary to comply with applicable law for the continued operation of Chehalis, for the benefit of Idaho customers, and were prudently incurred by the Company.

Q. Do these prudently incurred costs benefit Idaho customers?

A. Yes. Idaho customers received the benefit of the generation from the Chehalis natural gas facility which reduced NPC. NPC would have increased by $23.6 million on a total-Company basis if the generation from Chehalis were removed. Accordingly, as with other taxes and compliance costs imposed on the Company by state and federal governments, customer rates should reflect the full costs for this generation including the costs to comply with Washington CCA.

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, 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 petitioners', including PacifiCorp, motion to stay the EPA's final disapproval of Utah's OTR state implementation plan ("SIP") on July 27, 2023; and (2) 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 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 net power costs to comply with the prospective OTR requirements.

Q. Are other environmental compliance costs included in Idaho 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. Idaho customers pay these environmental compliance and generation tax costs incurred by resources that are used to serve Idaho customers.

IMPACT OF PARTICIPATING IN THE WEIM

Q. Are the actual benefits from participating in the WEIM with CAISO included in the ECAM deferral?

A. Yes. Participation in the WEIM provides benefits to customers in the form of reduced Actual NPC. The WEIM benefits are embedded in Actual NPC through lower fuel and purchased power costs. According to CAISO's WEIM benefits report, PacifiCorp has received $154 million in benefits in 2023 and $746 million since the inception of the WEIM.

CONCLUSION

Q. Please summarize your testimony.

A. The ECAM deferral of $62.4 million, including interest, for the Deferral Period, was accurately calculated in compliance with previous Commission orders. Therefore, I respectfully request that the Commission approve this application as filed with rates effective June 1, 2024.

Q. Does this conclude your direct testimony?

A. Yes.

Case No. PAC-E-24-05
Exhibit No. 1
Witness: Jack Painter

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Jack Painter

April 2024

Idaho Energy Cost Adjustment Mechanism Deferral
January 1, 2023 - December 31, 2023

Line No.			CY 2021
1	ID Base NPC Em	PAC-E-21-07	$ 86,534,565
2	Annual Idaho Bas	PAC-E-21-07	3,526,359
3	NPC Rate Embec	Line 1 / Line 2	$ 24.54

Line No.			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
4	NPC Rate Embec	Line 3	$ 24.54	$ 24.54	$ 24.54	$ 24.54	$ 24.54	$ 24.54	$ 24.54	$ 24.54	$ 24.54	$ 24.54	$ 24.54	$ 24.54	
5	ID Actual Sales @ Meter (MWh)		299,332	266,756	287,605	267,422	266,927	312,992	453,764	332,398	273,090	259,513	256,625	219,155	
6	ID NPC Collected	Line 4 x Line 5	$ 7,345,407	$ 6,546,028	$ 7,057,643	$ 6,562,371	$ 6,550,208	$ 7,680,628	$ 11,135,084	$ 8,156,825	$ 6,701,462	$ 6,368,292	$ 6,297,415	$ 5,377,911	$ 85,779,273
7	Total Company A	Adjusted Actual N	$ 197,232,836	$ 215,132,289	$ 214,137,197	$ 162,052,729	$ 160,452,428	$ 178,795,711	$ 297,171,442	$ 302,134,695	$ 233,832,184	$ 176,643,130	$ 199,091,621	$ 197,106,207	$ 2,533,782,470
8	Total Company Load @ Input (MWI		5,470,924	4,920,330	5,135,244	4,554,467	4,596,442	4,727,056	5,971,190	5,598,864	4,669,059	4,659,078	4,854,047	5,249,636	60,406,339
9	Actual NPC ($/M\	Line 7 / Line 8	$ 36.05	$ 43.72	$ 41.70	$ 35.58	$ 34.91	$ 37.82	$ 49.77	$ 53.96	$ 50.08	$ 37.91	$ 41.02	$ 37.55	$ 41.95
10	ID Actual Load @ Input (MWh)		303,538	284,568	294,802	252,861	273,264	368,186	481,082	318,523	285,199	258,137	221,546	245,710	
11	Actual ID NPC	Line 9 x Line 10	$ 10,942,879	$ 12,442,212	$ 12,293,097	$ 8,997,068	$ 9,539,095	$ 13,926,241	$ 23,942,267	$ 17,188,614	$ 14,283,130	$ 9,786,957	$ 9,086,860	$ 9,225,583	$ 151,654,001
12	NPC Differential	Line 11 - Line 6	**$ 3,597,472**	**$ 5,896,183**	**$ 5,235,454**	**$ 2,434,697**	**$ 2,988,887**	**$ 6,245,613**	**$ 12,807,183**	**$ 9,031,789**	**$ 7,581,668**	**$ 3,418,665**	**$ 2,789,445**	**$ 3,847,671**	**$ 65,874,728**
	EITF 04-6 Adjustment														
13	Idaho Allocated EITF 04-6 Deferral		**$ 57,959**	**$ (40,638)**	**$ (82,041)**	**$ (115,519)**	**$ (110,664)**	**$ 65,081**	**$ 106,954**	**$ 36,135**	**$ 50,297**	**$ 85,302**	**$ 25,322**	**$ (17,593)**	**$ 60,594**
	LCAR														
14	Actual Idaho Juris	PAC-E-21-07	$ 2,568,242	$ 2,568,242	$ 2,568,242	$ 2,568,242	$ 2,568,242	$ 2,568,242	$ 2,568,242	$ 2,568,242	$ 2,568,242	$ 2,568,242	$ 2,568,242	$ 2,568,242	$ 30,818,909
15	LCAR Rate @ Me	PAC-E-21-07	$ 8.74	$ 8.74	$ 8.74	$ 8.74	$ 8.74	$ 8.74	$ 8.74	$ 8.74	$ 8.74	$ 8.74	$ 8.74	$ 8.74	
16	ID Actual Sales @	Line 5	299,332	266,756	287,605	267,422	266,927	312,992	453,764	332,398	273,090	259,513	256,625	219,155	
17	LCAR Revenue C	Line 15 x Line 16	$ 2,616,035	$ 2,331,339	$ 2,513,549	$ 2,337,160	$ 2,332,828	$ 2,735,422	$ 3,965,712	$ 2,905,018	$ 2,386,697	$ 2,268,039	$ 2,242,797	$ 1,915,320	$ 30,549,915
18	LCAR Adjustmen	Line 14 - Line 17	**$ (47,792)**	**$ 236,903**	**$ 54,694**	**$ 231,082**	**$ 235,414**	**$ (167,180)**	**$ (1,397,469)**	**$ (336,775)**	**$ 181,546**	**$ 300,203**	**$ 325,446**	**$ 652,923**	**$ 268,994**
	ECAM Deferral														
19	Total ECAM Defe	Sum of Lines: 12, 13, 18	3,607,639	6,092,448	5,208,107	2,550,260	3,113,637	6,143,514	11,516,667	8,731,149	7,813,511	3,804,170	3,140,213	4,483,002	66,204,316
20	**Total ECAM Def**	Line 19 x 90%	**$ 3,246,875**	**$ 5,483,203**	**$ 4,687,296**	**$ 2,295,234**	**$ 2,802,273**	**$ 5,529,163**	**$ 10,365,000**	**$ 7,858,034**	**$ 7,032,160**	**$ 3,423,753**	**$ 2,826,192**	**$ 4,034,701**	**$ 59,583,884**
	Production Tax Credits (PTCs)														
21	ID Allocated PTC	PAC-E-21-07	$ (4.16)	$ (4.16)	$ (4.16)	$ (4.16)	$ (4.16)	$ (4.16)	$ (4.16)	$ (4.16)	$ (4.16)	$ (4.16)	$ (4.16)	$ (4.16)	
22	ID Actual Sales @	Line 5	299,332	266,756	287,605	267,422	266,927	312,992	453,764	332,398	273,090	259,513	256,625	219,155	
23	ID PTCs in Rates	Line 21 x Line 22	$ (1,246,393)	$ (1,110,752)	$ (1,197,565)	$ (1,113,525)	$ (1,111,461)	$ (1,303,275)	$ (1,889,439)	$ (1,384,077)	$ (1,137,127)	$ (1,080,593)	$ (1,068,566)	$ (912,542)	
24	ID Allocated Actual PTCs ($)		(1,506,351)	(1,527,575)	(1,349,209)	(1,300,860)	(898,278)	(825,256)	(760,968)	(878,133)	(855,476)	(881,682)	(1,455,204)	(1,409,147)	
25	ID PTCs Deferral	Line 24 - Line 23	**$ (259,958)**	**$ (416,823)**	**$ (151,644)**	**$ (187,335)**	**$ 213,183**	**$ 478,018**	**$ 1,128,470**	**$ 505,944**	**$ 281,651**	**$ 198,911**	**$ (386,637)**	**$ (496,605)**	**$ 907,177**
	Situs Assigned REP QF Adjustment														
26	ID REP QF Adjustment ($)		**$ 45,334**	**$ 50,891**	**$ 38,540**	**$ 102,024**	**$ 133,317**	**$ 198,289**	**$ 177,707**	**$ 130,328**	**$ 93,656**	**$ 168,692**	**$ 142,411**	**$ 168,941**	**$ 1,450,130**
	Wind Liquidated Damages														
27	ID Allocated Wind Liquidated Dama		**$ -**	**$ (14,654)**	**$ -**	**$ -**	**$ -**	**$ -**	**$ (19,635)**	**$ (275,795)**	**$ -**	**$ -**	**$ -**	**$ -**	**$ (310,085)**
	Renewable Energy Credits (REC) Revenue														
28	ID REC Revenue	PAC-E-21-07	$ (0.07)	$ (0.07)	$ (0.07)	$ (0.07)	$ (0.07)	$ (0.07)	$ (0.07)	$ (0.07)	$ (0.07)	$ (0.07)	$ (0.07)	$ (0.07)	
29	ID Actual Sales @	Line 5	299,332	266,756	287,605	267,422	266,927	312,992	453,764	332,398	273,090	259,513	256,625	219,155	
30	ID REC Revenue	Line 28 x Line 29	$ (20,489)	$ (18,260)	$ (19,687)	$ (18,305)	$ (18,271)	$ (21,424)	$ (31,060)	$ (22,753)	$ (18,693)	$ (17,764)	$ (17,566)	$ (15,001)	
31	ID Allocated Actual REC Revenue (		(5,402)	(118,766)	(228,071)	(97,144)	(39,468)	(3,729)	(30,448)	25,704	(2,060)	(2,591)	(20,916)	(73,691)	
32	REC Revenue Ad	Line 31 - Line 30	**$ 15,087**	**$ (100,506)**	**$ (208,384)**	**$ (78,838)**	**$ (21,197)**	**$ 17,696**	**$ 612**	**$ 48,456**	**$ 16,633**	**$ 15,172**	**$ (3,349)**	**$ (58,690)**	**$ (357,308)**
33	**Total Deferral**	Sum of Lines 20,	**$ 3,047,338**	**$ 5,002,111**	**$ 4,365,808**	**$ 2,131,085**	**$ 3,127,577**	**$ 6,223,166**	**$ 11,652,155**	**$ 8,266,967**	**$ 7,424,100**	**$ 3,806,528**	**$ 2,578,616**	**$ 3,648,347**	**$ 61,273,798**
34	Interest Rate	Order No. 35621	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	
	ECAM Balancing Account ($)														
35	Beginning Balance		$ 41,941,478	$ 42,982,959	$ 45,069,883	$ 48,401,960	$ 47,865,290	$ 50,134,661	$ 54,308,273	$ 61,339,814	$ 67,113,506	$ 72,023,580	$ 73,546,372	$ 73,543,853	
36	ECAM Deferral A	Line 20	3,246,875	5,483,203	4,687,296	2,295,234	2,802,273	5,529,163	10,365,000	7,858,034	7,032,160	3,423,753	2,826,192	4,034,701	
37	PTCs Deferral	Line 25	(259,958)	(416,823)	(151,644)	(187,335)	213,183	478,018	1,128,470	505,944	281,651	198,911	(386,637)	(496,605)	
38	REP Situs Adjust	Line 26	45,334	50,891	38,540	102,024	133,317	198,289	177,707	130,328	93,656	168,692	142,411	168,941	
39	Wind Liquidated [	Line 27	-	(14,654)	-	-	-	-	(19,635)	(275,795)	-	-	-	-	
40	REC Revenue Ad	Line 32	15,087	(100,506)	(208,384)	(78,838)	(21,197)	17,696	612	48,456	16,633	15,172	(3,349)	(58,690)	
41	Less: Monthly ECAM Rider Revenu		(2,076,569)	(2,988,503)	(1,111,559)	(2,747,911)	(939,804)	(2,136,517)	(4,716,907)	(2,600,231)	(2,629,876)	(2,404,944)	(2,703,608)	(1,896,726)	
42	Interest		70,711	73,316	77,828	80,156	81,599	86,963	96,293	106,955	115,851	121,207	122,473	124,033	
43	**Total ECAM Deferral Balance ($)**		**$ 42,982,959**	**$ 45,069,883**	**$ 48,401,960**	**$ 47,865,290**	**$ 50,134,661**	**$ 54,308,273**	**$ 61,339,814**	**$ 67,113,506**	**$ 72,023,580**	**$ 73,546,372**	**$ 73,543,853**	**$ 75,419,507**	**$ 75,419,507**

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER REQUESTING APPROVAL OF $62.4 MILLION ECAM DEFERRAL	))))	**CASE NO. PAC-E-24-05** **DIRECT TESTIMONY OF ROBERT M. MEREDITH**

ROCKY MOUNTAIN POWER

CASE NO. PAC-E-24-05

April 2024

Q. Please state your name, business address and present position with PacifiCorp, dba Rocky Mountain Power ("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.

Qualifications

Q. Briefly describe your educational and professional background.

A. I graduated from Oregon State University with a Bachelor of Science degree in Business Administration and a minor in Economics. 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.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have previously filed testimony on behalf of the Company in regulatory proceedings in Idaho, Utah, Wyoming, Oregon, Washington, and California.

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

A. My testimony presents and supports the Company's proposed rates to recover the 2023 Energy Cost Adjustment Mechanism ("ECAM") deferral balances through Electric Service Schedule No. 94, Energy Cost Adjustment ("Schedule 94").

Background

Q. What level of revenue is Schedule 94 currently designed to collect?

A. Schedule 94 is currently designed to collect approximately $32.2 million—$12.2 million for the Electric Service Schedule No. 400 ("Schedule 400") customer and $20.0 million for standard tariff customers—based on Idaho loads from Case No. PAC-E-21-07.

Proposed Rate Change for Schedule 94

Q. Please describe the Company's proposed rate change in this case.

A. The 2023 ECAM application proposes to increase Schedule 94 rates to recover approximately $64.9 million from June 1, 2024 to May 31, 2025. The $64.9 million includes $62.4 million for the 2023 ECAM Deferral, plus approximately $13.0 million remaining from the 2022 ECAM balance, for a total balance of $75.4 million as of December 31, 2023. This is offset by $10.5 million Schedule 94 forecasted revenue collection from January 1, 2024 through May 31, 2024, as shown in Table 2 of Mr. Jack Painter's testimony. Mr. Painter explains in his testimony the components of the 2023 ECAM deferred balance.

Q. What is the impact of the proposed ECAM rates?

A. As summarized in Exhibit No. 2, these rate change proposals result in an increase of 13.5 percent for Schedule 400. Standard tariff customers will see an average increase of 9.2 percent.

Renewable Energy Credit (REC) Revenue Treatment for Schedule 400

Q. Did the Company make any adjustments to the Schedule 94 ECAM price for Schedule 400?

A. Yes. Consistent with the 2022 ECAM, the Company created a different ECAM rate for Schedule 400 to exclude the REC revenues in the ECAM from Schedule 400's rates.

Q. Why are REC revenues excluded from Schedule 400 rates?

A. On March 29, 2021, PacifiCorp filed an application requesting Commission approval of an agreement entered into with the sole Schedule 400 customer under which the Company will retire, rather than sell, this customer's allocated share of RECs generated post-2020 from system resources.[1] The Company discontinued sale of Idaho-allocated system RECs associated with the Schedule 400 load in 2021, so that the Schedule 400 customer's allocated share of system RECs could be retired on its behalf. The REC revenue that Schedule 400 would otherwise have been allocated from the sale of post-2020 system RECs is removed from Schedule 400's base rates. Schedule 400 will continue to receive REC revenue from the sale of any RECs generated prior to 2021.

On August 11, 2021, Commission Order No. 35131 approved this agreement. Based on the terms of the agreement, the Company withheld the Schedule 400 customer's share of 2021 RECs from any auctions or sales. Beginning on January 1, 2021, the Schedule 400 customer will no longer receive a REC revenue credit for RECs generated after December 31, 2020. If the Company was able to sell RECs generated prior to 2021, Schedule 400 will receive credit for its share of those REC revenues.

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[1] *In the Matter of the Joint Application Between Rocky Mountain Power and P4 Production, L.L.C. Requesting Approval of an Agreement to Retire RECS,* Case No. PAC-E-21-08, Order No. 35131.

Q. How did you calculate the Schedule 400 ECAM rate?

A. To calculate the Schedule 400 ECAM rate, the Company removed REC revenue credits in the ECAM from the transmission voltage rate.

Q. Did you remove all of the REC revenue credits in Schedule 400 rates through the ECAM?

A. No. The ECAM only tracks the incremental difference between actual REC revenues received during the deferral period and the REC revenue credit in base rates. The base rates were established in Case No. PAC-E-21-07 with a REC revenue credit of seven cents per megawatt hour. Base REC sales were removed from Schedule 400's base rates to reflect Schedule 400's agreement with the Company to retire its share of RECs on its behalf.

Calculation of Proposed Rates for Schedule 94

Q. How were the proposed Schedule 94 rates developed for all customers?

A. The proposed rates for all customers were developed in five steps. First, kilowatt-hour ("kWh") consumption at the generation level was developed by multiplying their retail loads at the delivery service voltage level with the corresponding line loss factors. Second, an overall average rate at the generation level was developed by dividing the total collection target identified above by their kWh consumption at the generation level. Third, rates by delivery voltage level were developed by multiplying the above overall average rate at the generation level with the corresponding line loss factors. Fourth, the rate for Schedule 400 was increased by 0.01 cents per kWh to account for the $0.4 million adjustment to REC revenue included in the 2023 ECAM, which Contract Tariff 400 had elected to forego per the terms of the REC agreement. This results in a proposed

$24.6 million ECAM recovery from the Schedule 400 customer. Finally, the overall proposed collection of $64.9 million was reduced by the $24.6 million share for Schedule 400, and rates for standard tariff customers were developed to collect the remaining $40.3 million using similar logic to that described in the third step. As a result, the Company proposes Schedule 94 rates for standard tariff customers of 1.878, 1.844 and 1.782 cents per kWh for secondary, primary, and transmission delivery service voltages, respectively. The rate for Schedule 400 is 1.798 cents per kWh.

Q. Please describe Exhibit No. 2.

A. Exhibit No. 2 shows the 2020 loads used to develop rates, the line loss adjusted loads, the allocation of the ECAM price change, and the percentage change by rate schedule.

Q. Please describe Exhibit No. 3.

A. Exhibit No. 3 contains clean and legislative copies of the proposed Electric Service Schedule No. 94, Energy Cost Adjustment. The Company requests that the proposed Schedule 94 rates become effective on June 1, 2024.

Q. Does this conclude your direct testimony?

A. Yes.

Case No. PAC-E-24-05
Exhibit No. 2
Witness: Robert M. Meredith

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Robert M. Meredith

April 2024

EXHIBIT NO. 2
ROCKY MOUNTAIN POWER
ESTIMATED IMPACT OF PROPOSED ECAM ADJUSTMENT
FROM ELECTRIC SALES TO ULTIMATE CONSUMERS
DISTRIBUTED BY RATE SCHEDULES IN IDAHO
ADJUSTED HISTORICAL 12 MONTHS ENDED DECEMBER 2020

Line No.	Description	Sch.	Average Customers	MWH	Present Base ($000)	At Meter MWh by Voltage S	P	T	At Generation MWh	ECAM Proposal Rev ($000)	Rate ¢/kWh S	P	T	Present ECAM Rev ($000)	Net Change ($000)	%
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Residential															
1	Residential Service	1	55,659	523,107	$60,147	523,107			570,505	$9,825	1.878	1.844	1.782	$4,886	$4,939	7.6%
2	Residential Optional TOD	36	11,711	196,337	$19,448	196,337			214,128	$3,687	1.878	1.844	1.782	$1,834	$1,854	8.7%
3	AGA Revenue				$4											
4	**Total Residential**		67,370	719,444	$79,599	719,444	0	0	784,633	$13,512				$6,720	$6,793	7.9%
5	**Commercial & Industrial**															
6	General Service - Large Power	6	1,158	345,854	$27,087	303,007	42,847		376,344	$6,481	1.878	1.844	1.782	$3,223	$3,258	10.7%
7	General Svc. - Lg. Power (R&F)	6A	207	26,805	$2,326	26,656	149		29,231	$503	1.878	1.844	1.782	$250	$253	9.8%
8	*Subtotal-Schedule 6*		*1,365*	*372,659*	*$29,413*	*329,663*	*42,996*	*0*	*405,575*	*$6,984*				*$3,473*	*$3,511*	*10.7%*
9	General Service - High Voltage	9	17	222,699	$13,225	0	0	222,699	230,500	$3,969	1.878	1.844	1.782	$1,973	$1,996	13.1%
10	Irrigation	10	5,971	615,886	$55,363	615,886			671,691	$11,567	1.878	1.844	1.782	$5,752	$5,815	9.5%
11	General Service	23	7,734	183,016	$17,375	182,662	353	0	199,592	$3,437	1.878	1.844	1.782	$1,709	$1,728	9.1%
12	General Service (R&F)	23A	2,576	39,710	$3,922	38,626	1,084		43,287	$745	1.878	1.844	1.782	$371	$375	8.7%
13	*Subtotal-Schedule 23*		*10,310*	*222,726*	*21,298*	*221,289*	*1,437*	*0*	*242,879*	*4,183*				*2,080*	*2,103*	*9.0%*
14	General Service Optional TOD	35	2	278	$23	278			303	$5	1.878	1.844	1.782	$3	$3	10.3%
15	General Service Optional TOD (R&F)	35A	0	0	$0	0			0	$0	1.878	1.844	1.782	$0	$0	
16	*Subtotal-Schedule 35*		*2*	*278*	*23*	*278*	*0*	*0*	*303*	*5*	*1.878*	*1.844*	*1.782*	*3*	*3*	*10.3%*
17	Special Contract	400	1	1,369,716	$79,465			1,369,716	1,417,697	$24,631			1.798	$12,218	$12,413	13.5%
18	AGA Revenue				$602											
19	**Total Commercial & Industrial**		17,666	2,803,964	$199,389	1,167,116	44,433	1,592,415	2,968,646	$51,339				$25,499	$25,840	11.5%
20	**Public Street Lighting**															
21	Security Area Lighting	7	188	274	$50	274			298	$5	1.878	1.844	1.782	$3	$3	5.0%
22	Security Area Lighting (R&F)	7A	132	106	$24	106			115	$2	1.878	1.844	1.782	$1	$1	4.0%
23	Street Lighting - Company	11	57	154	$61	154			168	$3	1.878	1.844	1.782	$1	$1	2.3%
24	Street Lighting - Customer	12	256	2,417	$368	2,417			2,636	$45	1.878	1.844	1.782	$23	$23	5.8%
25	AGA Revenue				$0											
26	**Total Public Street Lighting**		633	2,950	$503	2,950	0	0	3,218	$55				$28	$28	5.2%
27	**Total Sales to Ultimate Customers**		85,669	3,526,359	$279,491	1,889,511	44,433	1,592,415	3,756,496	$64,907				$32,246	$32,660	10.5%
28	**Total Excluding Special Contract 400**		85,668	2,156,643	$200,026	1,889,511	44,433	222,699	2,338,799	$40,276				$20,029	$20,248	9.2%

Line No.		Rev. Rqmt	Unallocated	Allocated S	P	T		Proposed Rates S	P	T	Current Rates S	P	T
29	Voltage Line Loss Factors applied to rates (2018 Study):			1.09061	1.07082	1.03503		S	P	T	S	P	T
30	Tariff Customer ECAM deferral and Rate (cents/kWh):	$40,276	1.722	1.878	1.844	1.782	Tariff Customer Rate	1.878	1.844	1.782	0.934	0.917	0.886
31	REC Adjustment and Rate (cents/kWh):	($357)	-0.010	-0.010	-0.010	-0.010	Schedule 400 Rate			1.798			0.892
32	Total Idaho ECAM Rate (cents/kWh):	$64,907	1.728	1.884	1.850	1.788			REC Adj	-$135			

Case No. PAC-E-24-05
Exhibit No. 3
Witness: Robert M. Meredith

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Robert M. Meredith

April 2024

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

Fifteenth ~~Fourteenth~~ Revision of Sheet No. 94.1
I.P.U.C. No. 1 **Canceling Fourteenth~~Thirteenth~~ Revision of Sheet No. 94.1**

ROCKY MOUNTAIN POWER

ELECTRIC SERVICE SCHEDULE NO. 94

STATE OF IDAHO

Energy Cost Adjustment

AVAILABILITY: At any point on the Company's interconnected system.

APPLICATION: This Schedule shall be applicable to all retail tariff Customers taking service under the Company's electric service schedules.

ENERGY COST ADJUSTMENT: The Energy Cost Adjustment is calculated to collect the accumulated difference between total Company Base Net Power Cost and total Company Actual Net Power Cost calculated on a cents per kWh basis.

MONTHLY BILL: In addition to the Monthly Charges contained in the Customer's applicable schedule, all monthly bills shall have applied the following cents per kilowatt-hour rate by delivery voltage.

		Delivery Voltage		
		Secondary	Primary	Transmission
Schedule	1	1.878~~0.934~~¢ per kWh		
Schedule	6	1.878~~0.934~~¢ per kWh	1.844~~0.917~~¢ per kWh	
Schedule	6A	1.878~~0.934~~¢ per kWh	1.844~~0.917~~¢ per kWh	
Schedule	7	1.878~~0.934~~¢ per kWh		
Schedule	7A	1.878~~0.934~~¢ per kWh		
Schedule	9			1.782~~0.886~~¢ per kWh
Schedule	10	1.878~~0.934~~¢ per kWh		
Schedule	11	1.878~~0.934~~¢ per kWh		
Schedule	12	1.878~~0.934~~¢ per kWh		
Schedule	23	1.878~~0.934~~¢ per kWh	1.844~~0.917~~¢ per kWh	
Schedule	23A	1.878~~0.934~~¢ per kWh	1.844~~0.917~~¢ per kWh	
Schedule	24	1.878~~0.934~~¢ per kWh	1.844~~0.917~~¢ per kWh	
Schedule	35	1.878~~0.934~~¢ per kWh	1.844~~0.917~~¢ per kWh	
Schedule	35A	1.878~~0.934~~¢ per kWh	1.844~~0.917~~¢ per kWh	
Schedule	36	1.878~~0.934~~¢ per kWh		
Schedule	400			1.798~~0.892~~¢ per kWh

Fifteenth Revision of Sheet No. 94.1
I.P.U.C. No. 1 **Canceling Fourteenth Revision of Sheet No. 94.1**

ROCKY MOUNTAIN POWER

ELECTRIC SERVICE SCHEDULE NO. 94

STATE OF IDAHO

Energy Cost Adjustment

AVAILABILITY: At any point on the Company's interconnected system.

APPLICATION: This Schedule shall be applicable to all retail tariff Customers taking service under the Company's electric service schedules.

ENERGY COST ADJUSTMENT: The Energy Cost Adjustment is calculated to collect the accumulated difference between total Company Base Net Power Cost and total Company Actual Net Power Cost calculated on a cents per kWh basis.

MONTHLY BILL: In addition to the Monthly Charges contained in the Customer's applicable schedule, all monthly bills shall have applied the following cents per kilowatt-hour rate by delivery voltage.

		Delivery Voltage		
		Secondary	Primary	Transmission
Schedule	1	1.878¢ per kWh		
Schedule	6	1.878¢ per kWh	1.844¢ per kWh	
Schedule	6A	1.878¢ per kWh	1.844¢ per kWh	
Schedule	7	1.878¢ per kWh		
Schedule	7A	1.878¢ per kWh		
Schedule	9			1.782¢ per kWh
Schedule	10	1.878¢ per kWh		
Schedule	11	1.878¢ per kWh		
Schedule	12	1.878¢ per kWh		
Schedule	23	1.878¢ per kWh	1.844¢ per kWh	
Schedule	23A	1.878¢ per kWh	1.844¢ per kWh	
Schedule	24	1.878¢ per kWh	1.844¢ per kWh	
Schedule	35	1.878¢ per kWh	1.844¢ per kWh	
Schedule	35A	1.878¢ per kWh	1.844¢ per kWh	
Schedule	36	1.878¢ per kWh		
Schedule	400			1.798¢ per kWh

Submitted Under Case No. PAC-E-24-05

ISSUED: April 1, 2024 **EFFECTIVE**: June 1, 2024