

**BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**

**IN THE MATTER OF ROCKY MOUNTAIN ) CASE NO. PAC-E-26-05**  
**POWER’S APPLICATION REQUESTING )**  
**APPROVAL TO RECOVER \$4.1 MILLION )**  
**ASSOCIATED WITH THE ECAM ) ORDER NO. 37051**  
**DEFERRAL AND REFUND \$1.4 MILLION )**  
**ASSOCIATED WITH THE RRA )**  
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On April 1, 2026, Rocky Mountain Power, a division of PacifiCorp (“Company”) applied to the Idaho Public Utilities Commission (“Commission”) requesting authorization to adjust its rates under the Energy Cost Adjustment Mechanism (“ECAM”), effective June 1, 2026 (“Application”). Application at 1. The Company requested approval of: (1) approximately \$4.1 million in ECAM deferral—and a corresponding 0.7% decrease to Schedule No. 94, Energy Cost Adjustment (“Schedule 94”); and (2) returning approximately \$1.4 million in renewable energy credit (“REC”) revenue to customers under Schedule No. 98, REC Revenue Adjustment (“Schedule 98”)—and a corresponding 0.4% decrease in rates.<sup>1</sup> *Id.*

On April 20, 2026, the Commission issued a Notice of Application and a Notice of Modified Procedure, establishing public comment and Company reply deadlines. Order No. 37006. Commission Staff (“Staff”) filed comments to which the Company replied briefly asking the Commission to adopt the recommendations outlined in Staff’s comments.

Based on our review of the record, we issue this Final Order approving the Company’s ECAM deferral balance, the return of REC revenues through the REC Revenue Adjustment, and Schedules 94 and 98 as filed, effective June 1, 2026.

**BACKGROUND**

The ECAM allows the Company to increase or decrease its rates each year to reflect changes in the Company’s power supply costs. These costs vary by year with changes in the Company’s fuel (gas and coal) costs, surplus power sales, power purchases, and associated transmission costs. Each month, the Company tracks the difference between the actual net power

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<sup>1</sup> Prior to 2024, the Company’s REC revenues were included in the ECAM. In its 2024 rate case, the Company proposed returning REC revenues in a separate schedule, which was approved by the Commission in Order No. 36452.

costs (“NPC”) it incurred to serve customers, and the embedded (or base) NPC it collected from customers through base rates established in the most recent general rate case. The Company defers the difference between actual NPC and base NPC—higher or lower—into a balancing account for treatment at the end of the yearly deferral period. At that time, the ECAM allows the Company to credit or collect through a surcharge the difference between actual NPC and base NPC through a temporary decrease or increase in customer rates in Schedule 94.

### **THE APPLICATION**

The Company represented that in addition to the NPC difference, the Company’s proposed ECAM adjustment under Schedule 94 for January 1, 2025 through December 31, 2025, included: (1) Load Change Adjustment Revenues (“LCAR”); (2) coal stripping costs under Emerging Issues Task Force 04-6 (“EITF”); (3) Production Tax Credits (“PTC”); (4) the reasonable energy price, as defined in the 2020 Protocol; (5) qualified facility costs; and (6) wind availability liquidated damages. Application at 3.

The Company requested approval to implement its proposed Schedule 94 rates of 1.064, 1.044, and 1.009 cents per kilowatt-hour (“kWh”) for secondary, primary, and transmission delivery service voltages, respectively. *Id.* at 7. Under its proposal, the Company would return approximately \$1.4 million to customers. *Id.* at 8. The Company represented that if approved, the proposed Schedule 94 rates would result in a 0.6% decrease for standard tariff customers, a 1.1% decrease for Schedule 400 customers, and an overall 0.7% decrease for Idaho customers. *Id.* at 7.

The Company also requested approval to implement its proposed rates for Schedule 98. *Id.* at 8. The Company stated that if the proposed Schedule 98 rates were approved, there would be a 0.6% decrease for standard tariff customers, no change for Schedule 400 customers, and an overall 0.4% decrease for Idaho customers. *Id.* at 8–9.

### **STAFF COMMENTS**

#### **1. ECAM Analysis and Calculation.**

Staff recommended the Commission approve the Company’s \$49,331,797 ECAM deferral for 2025. Staff Comments at 2. To develop these recommendations, Staff reviewed the Company’s ECAM deferral calculation, confirming it accurately reflected actual loads, costs, and revenues, and was consistent with prior Commission orders. *Id.* Staff also verified that the application of base rate components was correct. *Id.* To ensure accuracy, Staff: (1) reviewed audit reports, journal

entries, invoices, and contracts; (2) reviewed evaluation adjustments to NPC costs; and (3) reconciled ledger amounts, assessed hedge contracts for compliance, and verified Energy Imbalance Market revenues included in the Company’s ECAM calculation. *Id.* at 3. Staff outlined the Company’s 2025 ECAM deferral in the following table:

**Table No. 1: Deferred ECAM Balance**

NPC Differential for Deferral	\$ 2,631,661
EITF 04-6 Adjustment	84,392
LCAR	(2,146,378)
Wheeling Revenues	34,954
Total Deferral Before Sharing	604,629
Sharing Band	90%
Customer Responsibility	544,166
Production Tax Credits	(1,047,075)
REP QF Adjustment	1,308,827
Wind Liquidated Damages	(265,256)
REC Deferral	21,598
Interest on Deferral	3,522,536
Annual Deferral (Jan - Dec 2025)	4,084,796
Unamortized Previous Balance	88,620,076
ECAM Rider Revenues	(43,373,074)
Total Company Recovery	\$ 49,331,797

*Id.*

Staff calculated the NPC to serve Idaho customers was \$139.0 million but the revenue collected through base rates was only \$136.4 million. *Id.* at 4. After applying the 90/10 sharing band, Staff calculated the Company’s customers are responsible for \$544,166 through the ECAM. *Id.* Regarding the EITF adjustment, Staff calculated that the EITF increased the ECAM deferral by \$84,392 before applying the 90/10 sharing band. *Id.* Regarding the LCAR, Staff stated that Order No. 36452 set the Company’s LCAR rate at \$6.29 per megawatt hour (“MWh”) for February 2025 through December 2025. *Id.* at 5. Staff calculated that the Company collected \$25.4 million through the LCAR. *Id.* Staff determined that the difference between the collected \$25.4 million and the \$23.2 million embedded in base rates decreased the ECAM deferral by \$2.15 million. *Id.*

Regarding wheeling revenues, Staff explained that Order No. 36452 established an Idaho-allocated wheeling revenue rate of \$2.97 per MWh. *Id.* After applying the rate to billed energy consumption for Idaho during February 2025 to December 2025, Staff determined that the

difference between what was recovered through base rates, and the actual Idaho-allocated wheeling revenues, increased the ECAM deferral by \$34,954. *Id.*

Staff confirmed the PTC true-up rate was set at \$4.31 per MWh for February 2025 through December 2025 in accordance with Order No. 36452. *Id.* Staff also confirmed that the PTC true-up rate remained at \$4.16 per MWh for January 2025 in accordance with Order No. 35277. *Id.* Staff calculated in 2025 there was a \$16.3 million PTC benefit. *Id.* Actual PTCs allocated to Idaho customers were \$17.3 million. *Id.* Staff determined the difference between the PTC benefit, and what was allocated to Idaho customers, reduced the ECAM deferral by \$1.0 million. *Id.* Staff believed the Company applied the \$52,243 balancing account error credit (required by the Commission in Order No. 36621) to the 2025 ECAM filing. *Id.* at 6.

Staff reviewed the Company’s process for determining “the reasonable energy price and the contract energy price” for relevant qualifying facilities (“QF”) contracts and believed that the Company complied with the 2020 Protocol that was approved by the Commission in Order No. 34640. *Id.* Staff also confirmed the ECAM also included \$265,256 for the wind availability liquidated damages credit as required by Order No. 33954. *Id.* Staff believed that the ECAM only included a true-up for actual REC revenues for January 2025, which was consistent with Order No. 36452. *Id.* at 6–7.

Staff reviewed the Company’s interest calculation, method, and rate assumptions, including the Company’s use of a 5% interest rate, which matched the Commission approved customer deposit rate from Order No. 36390, and determined the calculation and application of the rate were reasonable. Staff Comments at 7.

## **2. Analysis of Actual NPC.**

Staff asserted that the ECAM deferral decreased due to a lower actual unit cost of energy at \$34.37 per MWh, compared to the \$36.91 per MWh cost included in base rates. *Id.* To assess the prudence of the Company’s NPC, Staff compared the energy amounts and costs in base rates to the actual energy use and costs in 2025 across various resource types, as illustrated in Table No. 2 below:

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**Table No. 2: Comparison of Base and Actual NPC**

Source	Amt of Energy (million MWh)		Amt of Energy % Change	Unit Cost (\$/MWh)		Unit Cost % Change
	Actual NPC	Base NPC		Actual NPC	Base NPC	
Wholesale Sales	4.04	4.39	-8.0%	44.81	61.10	-26.7%
Total Purchased Power	18.74	20.74	-9.6%	51.55	56.67	-9.0%
- Other Purchases	9.48	12.54	-24.5%	72.61	72.36	0.3%
- Long-term Purchase	9.27	8.20	13.1%	30.00	32.65	-8.1%
Coal Resource	23.29	22.11	5.3%	30.35	30.53	-0.6%
Gas Resource	15.38	11.95	28.7%	34.38	41.47	-17.1%
Hydro Resource	2.57	3.04	-15.5%	-	-	-
Other Resource (wind, solar, etc.)	8.28	7.07	17.0%	0.70	0.79	-11.1%
Total System	64.22	60.53	6.1%	34.37	37.50	-8.3%

*Id.* at 7–8. Staff found the lower NPC unit costs were mainly due to purchased power prices being lower and because more energy was produced from lower cost coal and gas resources. *Id.* at 8.

According to Staff’s analysis, the cost of energy from market purchases was 9.6% lower and the cost of energy from hydro generation was 15.5% lower. *Id.* Staff also determined that energy from coal and gas generation was 5.3% and 28.7% higher, respectively. *Id.* Staff believed NPC was mainly affected by: (1) the fact that purchased power and natural gas prices were lower; and (2) that there was a stable and consistent coal fuel supply. *Id.* Staff found that actual purchased power unit cost was 9.0% lower than the base and that actual natural gas unit cost was 17.1% lower. *Id.* at 8–9. Staff believed the lower gas prices decreased the costs for natural gas generation, which allowed the Company to use its gas units more, and reduced by 9.6% the amount of market purchases needed to meet load. *Id.* at 9.

Staff believed that the stabilization of coal fuel supply could reduce the Company’s need for purchased power to meet load because the Company could count on coal generation being available. *Id.* Staff believed the Company’s ability to use additional lower cost coal and gas generation in the deferral period helped lower the NPC cost. *Id.* Staff noted that as the Company relies more on gas generation and market purchases, the Company’s NPC will likely become more subject to the unpredictability of the markets for natural gas and wholesale electricity. *Id.* Staff

highlighted that the Company increased its long-term market purchases by 13.1% at a lower cost which hedged the Company’s “price risk for market purchases of natural gas and electricity.” *Id.*

Staff reviewed Company planned and forced outages for each of the Company’s thermal generating units that were provided in the Company’s Response to Staff’s Audit Request at No. 6. *Id.* Based on this review, Staff reached two conclusions: (1) the amount and causes of forced outage downtime were reasonable when compared to the previous year; and (2) both the planned and any additional unplanned downtime had clear justification and were deemed reasonable. *Id.* at 9–10.

Staff calculated line loss by comparing the Idaho load at input to the load at customer meters, as illustrated in Table No. 3 below, and found a 3.06% loss in 2025:

**Table No. 3: Comparison of Line Loss**

Category	2024	2025
ID Load at Input (MWh)	3,847,108	3,922,255
ID Sales (MWh)	3,727,500	3,802,242
Line Loss	3.11%	3.06%

*Id.* at 10. Staff noted the loss is lower than the line loss in 2024 and is below the 3.5% loss identified in the Company’s last line loss study completed in 2018. *Id.* Staff believed the result indicated that the Company’s line loss during 2025 was reasonable. *Id.*

### **3. Proposed Rates.**

Staff confirmed that the Company’s proposed Schedule 94 rates complied with Order No. 33440 and the settlement stipulation approved in Order No. 36452, the Company’s most recent general rate case. *Id.* Table No. 4 below illustrates Staff’s summary of the Company’s proposed rates for each customer type:

**Table No. 4: Comparison of Current and Proposed Schedule 94 Rates**

Service Type	Current Rates (cents/kWh)	Proposed Rates (cents/kWh)	Decrease (%)
Secondary Distribution	1.137	1.064	-6.42%
Primary Distribution	1.116	1.044	-6.45%
Transmission	1.079	1.009	-6.49%

*Id.* Staff determined that the Company’s proposed Schedule 94 rates would decrease overall revenue by 0.7%, though the impact would vary by customer class due to rate design differences.

*Id.* at 11. For residential customers, Staff believed the average overall revenue decrease would be 0.5%. *Id.* Staff calculated that under the proposed rates, a residential customer using 836 kWh per month “would pay \$0.61 less per month.” *Id.* Regarding the proposed Schedule 98 rates, Staff confirmed that the Company’s proposed rates complied with the REC Revenue Adjustment approved by the Commission in Order No. 36452. *Id.*

#### **4. Customer Notice and Press Release.**

Staff believed the press release and customer notice provided with the Application satisfied Rule 125 of the Commission’s Rules of Procedure (IDAPA 31.01.01.125). *Id.* Because the Commission set a comment deadline of May 8, 2026, Staff believed that some customers may not have had enough time to respond and thus recommended the Commission consider any late filed comments by customers. *Id.* at 12.

### **COMMISSION FINDINGS AND DECISION**

The Commission has jurisdiction over the Company’s Filing and the issues in this case under Title 61 of the Idaho Code including, *Idaho Code* §§ 61-501, -502, and -503. The Commission is empowered to investigate rates, charges, rules, regulations, practices, and contracts of all public utilities and to determine whether they are just, reasonable, preferential, discriminatory, or in violation of any provisions of law, and to fix the same by order. *Idaho Code* §§ 61-501, -502, and -503.

The Commission has reviewed the record in this case. Based on our review, we find it fair, just, and reasonable to approve the Company’s Application. Specifically, we approve of the Company recovering \$4,084,796 in deferred costs from the deferral period beginning January 1, 2025, through December 31, 2025, and a corresponding 0.7% decrease to Schedule 94. Additionally, we approve of the Company returning \$1,381,352 in REC revenue to customers under Schedule No. 98 and a corresponding 0.4% decrease in rates for Idaho customers.

### **ORDER**

IT IS HEREBY ORDERED that the Company’s Application for Schedule 94 deferred costs from the deferral period beginning January 1, 2025, through December 31, 2025, in the amount of \$4,084,796 is approved, effective June 1, 2026.


IT IS FURTHER ORDERED that the Company’s Application for a 0.7% decrease to Schedule 94 is approved, effective June 1, 2026.

IT IS FURTHER ORDERED that the Company's Application to return \$1,381,352 in REC Revenues through Schedule 98 to customers is approved, effective June 1, 2026.

IT IS FURTHER ORDERED that the Company's Application for a 0.4% decrease in Schedule 98 rates for Idaho customers is approved, effective June 1, 2026.

THIS IS A FINAL ORDER. Any person interested in this Order may petition for reconsideration within 21 days of the service date of this Order regarding any matter decided in this Order. Within seven days after any person has petitioned for reconsideration, any other person may cross-petition for reconsideration. *Idaho Code* § 61-626.


DONE by Order of the Idaho Public Utilities Commission at Boise, Idaho this 28<sup>th</sup> day of May 2026.

  
EDWARD LODGE, PRESIDENT

  
JOHN R. HAMMOND JR., COMMISSIONER

  
DAYN HARDIE, COMMISSIONER

ATTEST:

  
Monica Barrios-Sanchez  
Commission Secretary

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