

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION	)	CASE NO. PAC-E-25-02
OF ROCKY MOUNTAIN POWER FOR	)	
AUTHORITY TO IMPLEMENT CHANGES	)	
TO NON-LEGACY CUSTOMER	)	ORDER NO. 36845
GENERATORS	)	
	)	

On February 7, 2025, Rocky Mountain Power, a division of PacifiCorp (“Company”) applied to the Idaho Public Utilities Commission (“Commission”) requesting an order approving the Company’s proposed changes to its onsite self-generation Electric Service Schedule 136 (“Schedule 136”) tariff beginning October 1, 2025, and approving the Company’s proposed export credit rate methodology (“Application”).

The Commission issued a Notice of Modified Procedure setting deadlines for public comments and for the Company’s reply comments. Order No. 36482 at 1–2. The Commission also issued a Notice of Virtual Customer Hearing. *Id.* at 4. On July 30, 2025, the Company filed an amended application with the Commission (“Amended Application”). The Amended Application made changes to inputs used to calculate the export credit rate (“ECR”) for the Company’s Schedule 136 customers. Amended Application at 2–3. Accordingly, the Commission granted additional time to file public comments and reply comments, rescheduled the Customer Hearing, and suspended the Company’s proposed effective date. Order No. 36716 at 4–5.

Commission Staff (“Staff”) filed comments. The Company filed reply comments. The Commission also received 159 timely public comments and five late-filed public comments. Additionally, eight Company customers testified at the September 11, 2025, customer hearing.

Based on our review of the record, the Commission now issues this Final Order approving the Company’s requests with modifications as described below.

BACKGROUND

Due to longstanding concerns about potential cost shifting from on-site customer generators to non-participants under the structure of Schedule 135, Net Metering Service, on August 26, 2020, the Commission issued Proposed Order No. 34752, proposing to allow the Company to close Schedule 135 to new customers and to approve the Company’s request to open Schedule 136, Net Billing Service, as of October 1, 2020. Proposed Order No. 34752 at 8–10.

Schedule 136 was to have no immediate changes from Schedule 135 except for a one-time \$85 application fee. *Id.* at 10. However, Schedule 136 customers would be subject to program changes, whereas the terms of Schedule 135 would be fixed for a period of 25 years. *Id.* The Commission proposed granting grandfathered Schedule 135 customer status to metering sites for which an application to the Company for interconnection had been made as of the date of the anticipated order adopting Proposed Order No. 34752 and that were successfully interconnected within one year of the service date of the adopting order. *Id.* at 9–10. The Commission adopted Order No. 34752 on October 2, 2020, changing only the effective date of Schedule 136 to November 1, 2020. Order No. 34798 at 2.

The Commission also issued Order No. 34753 on August 26, 2020, directing the Company to perform a cost/benefit study of on-site customer generation. On August 8, 2024, the Commission confirmed the resulting study complied with the parameters provided in Order No. 34753. Order No. 36286 at 6–7. The Commission ordered the Company to file a new application within six months requesting changes to the structure and design of its proposed export credit rate for customer generators under Schedule 136 based on the study’s findings. *Id.* The Order also required the Company’s ECR filing to incorporate several items suggested in Staff’s Comments in Case No. PAC-E-23-17, including an analysis of the pros and cons of using a 100 kilowatt (“kW”) non-residential customer cap. *Id.* at 6-7.

THE APPLICATION

The Company requested the Commission confirm its ECR filing complied with Order No. 36286 and approve the Company’s proposed: (1) ECR for customers on Schedule 136; (2) increased cap for non-residential customers to 2,000 kW; (3) annual updates to the proposed ECR; and (4) revised Schedule 136 tariff. Application at 1.

The Company originally proposed to change the program to compensate customers on Schedule 136 for all exported energy at specified prices listed in Table 1 below.

Table 1: Export Credit Summary

Export Profile		Annual	Summer On- Peak	Summer Off-Peak	Winter On-Peak	Winter Off-Peak
Volume (kWh per kW)		949	119	329	35	466
Capacity Contribution (%)		10.97%	8.69%	1.97%	0.03%	0.28%

Value by Element (cents/kWh)

Energy	2.415	4.007	3.063	2.934	1.513
- Integration	(0.385)	(0.638)	(0.488)	(0.467)	(0.241)
+ Avoided Line Losses	0.184	0.304	0.233	0.223	0.115
Generation Capacity	1.488	9.408	0.770	0.121	0.078
Transmission Capacity Deferral	0.069	0.437	0.036	0.006	0.004
Transmission System Cost	0.297	1.707	0.023	1.878	0.011
Distribution Capacity Deferral	0.162	1.023	0.084	0.013	0.008
Total	4.230	16.248	3.721	4.708	1.489

(i) Annual values for information only and reflect seasonal weighting from the historical period.

Id. at 7–8. As demonstrated in Table 1, the proposed ECR varies significantly by season and time of day according to definitions to be contained in the updated Schedule 136 (Optional Time of Day - Residential Service). *Id.* at 8. The Company represented that such variation would more accurately reflect the timing value of exports than a static rate and would encourage customers to use their own generation instead of exporting when ECR is lower than retail rates. *Id.* at 8–9.

Rather than discussing the pros and cons of a fixed cap on the size of individual non-residential customer generation systems of 100 kW, as the Commission directed in Order No. 36286, the Company instead proposed increasing the cap to 2,000 kW. *Id.* at 9. The Company stated that the cap would allow for administrative ease by aligning with the Company’s tariffs in Utah and Oregon. *Id.* The Company represented that according to its analysis using Advanced Metering Infrastructure (“AMI”) data, 99.95% of non-residential customer generators have a non-coincident peak of less than 2,000 kW. *Id.* The Company did not plan to change the cap for residential customers. *Id.*

According to the Company, the proposed changes were intended to correct the cross-subsidy currently imposed on non-generating customers to the benefit of customer generators under the existing Schedule 136. *Id.* The Company planned to make a filing on or about July 1,

2026, and each following year, to revise the ECR for Schedule 136 customers as necessary, with prices to take effect on October 1 of each year. *Id.* The Company sought to treat export credits as a Purchased Power expense for ratemaking purposes. *Id.* at 7.

THE AMENDED APPLICATION

During the discovery phase of this case, the Company and Staff identified mistakes in the Company’s workpapers from which the proposed ECR was derived. Amended Application at 2–3. Accordingly, the Company filed the Amended Application incorporating the necessary corrections, which included classifying October as a summer month, rather than a winter month, in all instances and rectifying time zone and hourly inconsistencies on the Company’s ID Residential 136 Bill Impact Workpaper. *Id.* at 2–4.

The Company represented that the corrections did not change the proposed average ECR of 4.2 cents per kilowatt hour (“kWh”) but did impact the seasonal and hourly profile adjustments as demonstrated in Tables 2 and 3 below.

Table 2: Amended Export Credit Summary

Export Profile	Annual	Summer On-Peak	Summer Off-Peak	Winter On-Peak	Winter Off-Peak
Volume (kWh per kW)	949	136	387	18	409
Capacity Contribution (%)	10.97%	8.69%	1.97%	0.03%	0.28%

Value by Element (cents/kWh)

Energy	2.415	4.024	3.149	1.750	1.213
- Integration	(0.385)	(0.641)	(0.502)	(0.279)	(0.193)
+ Avoided Line Losses	0.184	0.306	0.239	0.133	0.092
Generation Capacity	1.488	8.212	0.655	0.240	0.089
Transmission Capacity Deferral	0.069	0.381	0.030	0.011	0.004
Transmission System Cost	0.297	1.490	0.020	3.716	0.013
Distribution Capacity Deferral	0.162	0.893	0.071	0.026	0.010
Total (as Amended)	4.230	14.666	3.664	5.597	1.228

(i) Annual values for information only and reflect seasonal weighting from the historical period.

Total (Initial Application)	4.230	16.248	3.721	4.708	1.489
Change from Application	0.000	-1.582	-0.057	0.890	-0.261

**Table 3: Net Impact of Season & Hourly Profile Adjustment
As Filed**

Net Delivered kWh Range	Customer Count	Current Monthly Average Bill	Proposed Monthly Average Bill	Change \$	Change %
A: 0-500 kWh	610	\$21.60	\$59.48	\$37.89	175.4%
B: 501-1,000 kWh	197	\$72.52	\$110.66	\$38.15	52.6%
C: 1,001-1,500 kWh	75	\$133.68	\$167.71	\$34.04	25.5%
D: 1,501-2,000 kWh	25	\$186.19	\$219.45	\$33.25	17.9%
E: 2,001 kWh+	20	\$298.86	\$326.88	\$28.02	9.4%
Grand Total	927	\$51.90	\$89.19	\$37.29	71.8%

Revised with Season & Hourly Profile Adjustment

Net Delivered kWh Range	Customer Count	Current Monthly Average Bill	Proposed Monthly Average Bill	Change \$	Change %
A: 0-500 kWh	610	\$21.16	\$56.86	\$35.70	168.7%
B: 501-1,000 kWh	197	\$71.03	\$107.47	\$36.44	51.3%
C: 1,001-1,500 kWh	75	\$131.72	\$164.58	\$32.86	24.9%
D: 1,501-2,000 kWh	25	\$184.41	\$216.41	\$31.99	17.4%
E: 2,001 kWh+	20	\$297.08	\$324.25	\$27.17	9.1%
Grand Total	927	\$51.05	\$86.39	\$35.35	69.2%

STAFF COMMENTS

Staff reviewed the Company's Application, Amended Application, supporting workpapers, and discovery responses. Staff Comments at 3. Staff believed the Company's ECR proposal was generally reasonable but recommended the Commission reject certain aspects of the Company's Amended Application and impose some additional requirements. *Id.* Staff recommended that the Commission issue an order:

1. Approving the Company's proposed ECR with the addition of a rate stabilization mechanism;
2. Requiring the Company to file annual ECR updates by July 1st of each year;
3. Requiring the Company to file updated workpapers as publicly available exhibits;
4. Denying the Company's proposal to increase the non-residential project cap to 2,000 kW and set the non-residential project cap at 100 kW or maximum demand, whichever is greater;

5. Requiring the Company to adjust its tariffs to explicitly state that the customer requesting on-site generation service is responsible for all costs related to studies and upgrades;
6. Requiring the Company to submit a compliance filing containing updated tariffs that reflect the Commission's Order.

Id.

Staff explained that its suggested ECR stabilization mechanism intended to mitigate year-to-year volatility. *Id.* at 8. Staff's proposal involved establishing a three-year rolling average of the four approved Season/Peak rates for calculating ECR values. *Id.* at 8–9.

Staff agreed with the Company that the ECR should be updated annually with revised calculations for its components using the most recent data. *Id.* at 13. However, Staff believed the Company's representation that it would file ECR update cases "on or around" July 1st of each year was too non-committal. *Id.* at 14. Instead, Staff recommended the Commission expressly require the Company to file its ECR update by July 1st of each year. *Id.* Staff noted that in this case the Company made public its pertinent workpapers, including hourly export data, market price data, and inputs from relevant sources. *Id.* at 13. In the interest of transparency, Staff recommended the Commission order the Company to continue to file such workpapers as publicly available exhibits in future ECR cases. *Id.*

Rather than support the Company's proposed increase to the eligibility cap for non-residential customers from 100 kW to 2,000 kW, Staff recommended the Commission approve an eligibility cap for non-residential customers to be 100 kW or each customer's maximum demand (defined as the customer's "greatest monthly billing demand established during the most recent 12-month period at the time of applying for interconnections"), whichever is greater. *Id.* at 14, 16. Staff was concerned that the Company's proposed 2,000 kW cap could contradict the intent of the program by allowing non-residential customers to install generation well over their own load demand. *Id.* at 16. Staff noted that its analysis of the Company's AMI data revealed that 91.07% of non-residential customers have non-coincident peaks lower than 100 kW. *Id.* Additionally, according to Staff, 94% of non-residential Idaho customers have non-coincident peaks lower than 100 kW. *Id.* However, Staff supported the Company's proposal to leave the eligibility cap at 25 kW for residential customers. *Id.* at 15.

Though Staff verified that the cost of any upgrades to an on-site generation customer's interconnection is recovered from the customer rather than being included in the rate base, Staff could not verify as much concerning the costs related to interconnection studies that identify needed upgrades. *Id.* at 15. Therefore, to ensure costs are not unfairly passed to other customers, Staff recommended the Commission require the Company's tariffs to expressly state that the customer requesting on-site generation interconnection is responsible for all costs related to studies and upgrades. *Id.*

Staff also addressed the items suggested in Staff's Comments in Case No. PAC-E-23-17 that Order No. 36286 required the Company's ECR filing to incorporate. Specifically, Staff agreed with the Company's proposed methods for: (1) calculating avoided energy value; (2) calculating integration costs for distributed solar exports; (3) determining line losses; (4) determining avoided generation capacity value (with the clarifications that in future updates, the Company should continue to use the annualized fixed cost of the least-cost dispatchable resource from its most recent Integrated Resource Plan ("IRP") to calculate the avoided generation capacity value, rather than permanently using the costs of a simple cycle combustion turbine, and future updates should draw loss of load probability data from the Company's most recent IRP); (5) valuing avoided transmission costs; (6) valuing the deferral of transmission capacity; (7) determining there are currently no avoided environmental costs for ratepayers; (8) real-time tracking of exported and delivered energy (real-time netting); and (9) determining seasonal and hourly variations in the ECR. *Id.* at 3–11.

Finally, Staff agreed with the Company's proposal to recover exported energy credits paid out to self-generators as a purchased power expense and with the Company's proposed flexible treatment of self-generators' accumulated financial credits. *Id.* at 17.

COMPANY REPLY COMMENTS

The Company agreed with Staff's recommendations concerning the ECR calculation, the timing requirement for annual ECR update filings, and the use of a rate stability mechanism. Company Reply Comments at 2.

The Company generally agreed with Staff's proposed non-residential customer project cap of the greater of 100 kW or the customer's maximum demand. *Id.* at 4. However, the Company was concerned about the lack of an upper limit on the cap. *Id.* According to the Company, customer generator systems larger than 2 megawatts ("MW") should become qualifying facilities under the

Public Utility Regulatory Policies Act of 1978, allowing such large facilities “to be integrated into the Company’s long-term resource planning while providing a regulatory framework more appropriate for a large generation system.” *Id.* Therefore, the Company proposed adopting a non-residential project cap at the greater of 100 kW or the customer’s peak demand (defined as the 15-minute period of the customer’s greatest use during the previous 12 months), but not to exceed 2 MW.

The Company believed Staff’s recommendation to require the Company to adjust its tariffs to explicitly state that the customer requesting on-site generation service is responsible for all costs related to studies and upgrades was largely unnecessary, as the Company contended the current language of Schedule 136 makes the customer responsible for all costs related to interconnecting their generation to the Company’s system. *Id.* at 4–5. Nevertheless, the Company attached a new proposed Schedule 136 to its Reply Comments, which expressly added the cost of reliability studies as an expense for which the self-generation customer is responsible: “The Customer is responsible for all costs associated with the Eligible Generating Plant and interconnection facilities, including additional metering necessary for service under this schedule and the cost of any reliability studies.” *Id.* at 5; Attachment A to Company Reply Comments at 5.

Finally, the Company requested the Commission discontinue the annual net metering reporting requirement imposed by Order No. 33511. According to the Company, the primary purpose of the report—keeping the Commission apprised of any cost-shifting from on-site generators to non-participating customers—should be satisfied in this case. Company Reply Comments at 5.

PUBLIC COMMENTS AND CUSTOMER HEARING

The Commission received 159 timely public comments and five late-filed public comments. Of the timely comments, 143 customers opposed the Company’s proposed ECR changes. The five late-filed comments were each critical of the proposed changes. The vast majority of these customers were non-legacy self-generators. The comments generally expressed frustration concerning the scope of the proposed rate changes, the cutoff date for granting grandfathered Schedule 135 status, and the non-focus on environmental benefits realized from incentivizing customer generation.

Each of the eight Customer Hearing participants were opposed to the proposed ECR changes. Their testimony reiterated many of the concerns expressed throughout the public comments.

COMMISSION FINDINGS AND DECISION

The Commission has jurisdiction over the Company's Application and the issues in this case under Title 61 of the Idaho Code including *Idaho Code* §§ 61-301 through 303. 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 through 503.

The Commission has examined the comprehensive record in this matter, including all comments submitted by the public, intervenors, and the Company. Based on its review of the record, the Commission finds it fair, just, and reasonable to approve certain portions of the Company's Application and Amended Application, as filed. We first confirm that the Company's proposed changes to its on-site self-generation Schedule 136 tariff adhere to Order No. 36286. The Commission also approves the Company's proposed ECR for customers on Schedule 136, effective for customer billing cycles beginning on or after December 1, 2025. Additionally, we approve of the proposed non-residential project cap of the greater of 100 kW or the customer's peak demand (defined as the 15-minute period of the customer's greatest use during the previous 12 months) not to exceed 2 MW while maintaining a residential cap of 25 kW. Finally, the Commission approves the language the Company included in the proposed Schedule 136 attached to its Reply Comments, which expressly includes the cost of reliability studies as an expense for which self-generation customers are responsible.

However, we also see fit to institute alterations to the Company's proposal. In recognition of concerns about fluctuating ECR, the Company shall maintain the ECR at the rates set by this Order until filing for an update on July 1, 2028. The proposed ECR in the Company's 2028 filing shall be calculated using an average of data from the three prior years. The Company's filing shall also include its updated workpapers from which the proposed ECR is calculated as publicly available exhibits.

Furthermore, the Company shall submit a compliance filing with an updated tariff sheet reflecting the conditions of this Order, and, as future ECR determinations will require the most

accurate data available, we direct the Company to continue submitting annual reports, consistent with Order No. 33511.

The Commission appreciates the public participation in this case. We will continue to monitor the Company's ECR and evaluate its effects on customer generators and non-participants.

ORDER

IT IS HEREBY ORDERED that the Company's proposed ECR for customers on Schedule 136 is approved, subject to the modifications set forth in this Order, effective for customer billing cycles beginning after December 1, 2025.

IT IS FURTHER ORDERED that the non-residential project cap shall be the greater of 100 kW or the customer's peak demand (defined as the 15-minute period of the customer's greatest use during the previous 12 months) not to exceed 2 MW, while the residential cap shall remain 25 kW.

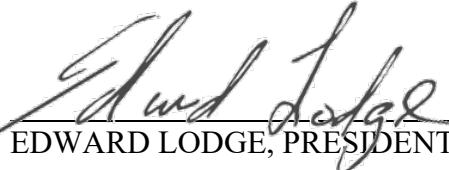
IT IS FURTHER ORDERED that the Company shall maintain the ECR at the rates set by this Order until filing for an update on July 1, 2028. The proposed ECR in the Company's 2028 filing shall be calculated using an average of data from the three prior years. The Company's ECR filing shall also include its updated workpapers from which the proposed ECR is calculated as publicly available exhibits.

IT IS FURTHER ORDERED that the Company shall submit, as a compliance filing, a corrected tariff sheet reflecting the updated ECR as modified by the Commission decision above within 30 days of this Order.

IT IS FURTHER ORDERED that the Company shall continue to submit annual reports pursuant to Order No. 33511.

THIS IS A FINAL ORDER. Any person interested in this Order may petition for reconsideration within twenty-one (21) days of the service date of this Order regarding any matter decided in this Order. Within seven (7) days after any person has petitioned for reconsideration, any other person may cross-petition for reconsideration. *See Idaho Code* § 61-626.

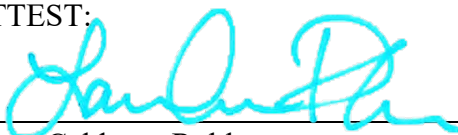
DONE by Order of the Idaho Public Utilities Commission at Boise, Idaho this 14th day of November 2025.


EDWARD LODGE, PRESIDENT


JOHN R. HAMMOND JR., COMMISSIONER


DAYN HARDIE, COMMISSIONER

ATTEST:


Laura Calderon Robles
Interim Commission Secretary

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