Office of the Secretary
Service Date
July 1, 2026

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF ROCKY MOUNTAIN POWER'S APPLICATION FOR AUTHORIZATION TO UPDATE THE WIND AND SOLAR INTEGRATION RATE FOR SMALL POWER GENERATION QUALIFYING FACILITIES	)))))))	**CASE NO. PAC-E-26-01** **ORDER NO. 37086**

On January 16, 2026, Rocky Mountain Power, a division of PacifiCorp ("Company") applied to the Idaho Public Utilities Commission ("Commission") requesting authority to adjust the wind and solar integration rates applicable to new power purchase agreements ("PPA") between the Company and wind and solar qualifying facilities ("QFs") ("Application").

On February 9, 2026, the Commission issued a Notice of Application and Notice of Modified Procedure, establishing deadlines for public comments and Company reply comments. Order No. 36931. No public comments were received.

Based on our review of the record, the Commission issues this Final Order approving the wind and solar integration rates proposed by the Company and reflected in Attachment A to Commission Staff's ("Staff") Comments and requiring the Company to file a Flexible Reserve Study ("FRS") within six months following each Integrated Resource Plan ("IRP") going forward.

BACKGROUND

In 2007, the Company requested approval of a utility-specific wind integration adjustment to the published avoided cost rates. *See* Case No. PAC-E-07-07. The Commission approved a stipulation by the parties and determined "that a utility-specific wind integration cost adjustment to a utility's published avoided costs, among other adjustments, was appropriate." Application at 2 citing Order No. 30497 at 12. Additionally, the Commission ordered the Company to file any changes to its wind integration charge as reflected in future Integrated Resource Plans ("IRP"). *Id.* citing Order No. 30497 at 13.

THE APPLICATION

The Company's proposed an integration rate for electricity purchased from wind-powered QFs of $1.45 per megawatt-hour ("MWh") for 2026, with a corresponding 20-year levelized rate of $0.36 per MWh for contracts beginning that year. Application at 1. The proposed rate represents

a decrease from the current wind integration charge of $3.51 per MWh, or $0.83 per MWh on a 20-year levelized basis. *Id.*

For solar-powered QFs, the Company proposed an integration rate of $1.61 per MWh for 2026, with a levelized price of $0.58 per MWh for a 20-year contract commencing in 2026. *Id.* These proposed solar rates are also lower than existing integration charges—currently $4.80 per MWh, or $1.35 per MWh when levelized over 20 years. *Id.*

The Commission approved the Company's 2025 IRP on December 17, 2025. Order No. 36868. The Company believed that the proposed wind and solar integration rates reflect the variability and outcomes identified in the 2025 IRP and would be available in levelized form for multiple contract durations and in-service years. *Id.* at 1-2. The Company further explained that the proposed integration charges were designed to recover the costs associated with integrating wind and solar generation into the electric system and would be deducted from the Company's published avoided cost rates. *Id.* at 2. An exception would apply where a QF elects, through its PPAs, to deliver energy to the Company on an hourly scheduled basis. *Id.* at 2.

STAFF COMMENTS

Staff reviewed the Company's proposed wind and solar integration charges, focusing on compliance with Order No. 36243, the accuracy of the integration charge methodology, and key assumptions underlying the Company's resource planning and reserve requirements. Staff Comments at 1-2. Staff believed the Company substantially satisfied the requirements established in Order No. 36243, including timely filing its FRS following acknowledgment of the 2025 IRP, evaluating hybrid resource treatment, quantifying the effects of load assumptions on portfolio diversity benefits, and assessing the relevance of inter-hour integration costs. *Id.* at 3-4. Staff also believed that the Company's rationale for excluding capital and fixed operation and maintenance costs associated with reserve-driven resource additions from the current integration charges were reasonable, given the evidence indicating that resource additions in the 2025 IRP were not driven by reserve requirements. *Id.* at 4-5.

Staff did express concern about the Company's continued reliance on historical operational data from 2018-2019 to develop its reserve requirements, despite the availability of more recent datasets. *Id.* at 5. Staff noted that the Company did not fully satisfy the requirement to use the most current data and recommended that the Company's future FRS incorporate the latest available operational information, including data associated with participation in the California Independent

System Operator's ("CAISO") Extended Day-Ahead Market ("EDAM"). *Id.* Staff also observed that the Company's IRP does not distinguish whether new resource additions are prompted by reserve requirements, capacity requirements, reliability needs, or economic considerations. *Id.* at 4-5. Because integration charges are intended to recover costs associated with reserve requirements, Staff recommended that future studies clearly identify when resource additions are driven by reserve needs and, if so, determine how the associated capital and fixed operation and maintenance costs should be allocated to integration charges. *Id.* at 5.

Staff further raised concerns regarding the application of integration charges to IRP-based avoided cost rates and recommended that such charges apply to both published and IRP-based avoided cost rates. *Id.* at 9-10. While acknowledging the Company's concern that integration charges and avoided cost rates could be based on different IRPs, Staff believed that this inconsistency would be largely resolved if integration studies were filed within six months of each IRP filing rather than after IRP acknowledgment. *Id.* at 10.

In addition, Staff reviewed the treatment of behind-the-meter generation and the potential for integration charges to be either underestimated or overestimated for these resources. *Id.* Staff noted that integration costs are currently calculated based on generation profiles but recovered based on export profiles, creating a potential mismatch that may understate actual integration costs. *Id.* Staff also recognized that behind-the-meter solar facilities generally lack the tracking technology and optimized panel-to-inverter configurations commonly found in utility-scale projects, resulting in greater variability and potentially higher integration costs. *Id.* At the same time, Staff identified the possibility that integration charges could be overstated because behind-the-meter customers function simultaneously as electric load and generation resources, making it difficult to separate load variability from generation variability when determining reserve requirements. *Id.* at 11. As a result, Staff recommended that future studies evaluate both potential underestimation and overestimation of integration charges, quantify the magnitude of any discrepancies, and examine whether behind-the-meter resources should be represented through proxy resources subject to wind and solar reserve requirements. *Id.* Staff further recommended that the Company assess whether existing behind-the-meter resources and future additions should be treated differently for integration charge purposes. *Id.*

Staff also questioned whether the assumptions used to develop integration charges accurately reflect actual renewable resource development trends on the Company's system. *Id.* at

12. The current study calculated integration costs based on incremental additions of five megawatts ("MW") of wind or solar generation above the preferred portfolio and assumed those additions remained constant throughout the planning horizon. *Id.* Staff believed that these assumptions did not align well with actual qualifying facility development patterns, which have occurred incrementally over time and at varying levels. *Id.* Consequently, Staff recommended that future studies evaluate renewable penetration levels that more closely reflect observed system trends and consider whether a tiered integration charge structure based on different penetration ranges would produce more accurate results. *Id.* Staff additionally expressed concern that including assumed renewals of existing qualifying facility contracts in the preferred portfolio could distort integration charge calculations by affecting the baseline resource mix against which incremental renewable additions are measured. *Id.* at 12-13. Accordingly, Staff recommended that the Company analyze whether QF renewals should be excluded from the preferred portfolio in future studies. *Id.* at 13.

Finally, Staff expressed its concerns regarding reliability assumptions and reserve-related costs. *Id.* Although the preferred portfolio was designed to satisfy both Western Resource Adequacy Program ("WRAP") capacity requirements and hourly reliability requirements, Staff noted that projected loss-of-load hours in certain years exceeded industry standards. *Id.* Staff recommended that future studies evaluate whether reliability targets for both energy supply and reserve shortfalls should be adjusted to ensure that total loss-of-load metrics remain within accepted industry thresholds throughout the planning horizon. *Id.* Staff also observed that the proposed integration charges account only for upward regulation reserve requirements and exclude downward regulation reserves because the Company can curtail non-QF wind and solar resources. *Id.* at 14. However, Staff questioned whether costs associated with curtailment provisions, backing down dispatchable resources, and other operational impacts of managing excess generation are being adequately captured. *Id.* Likewise, Staff recommended that the Company evaluate and address the costs associated with downward regulation reserves in future studies to ensure that integration charges more accurately reflect the full cost of integrating variable renewable resources. *Id.*

Based on its review, Staff recommended that the Commission approve the updated wind and solar integration charges and apply them to both published avoided cost rates and IRP-based avoided cost rates. *Id.* Staff further recommended that the Company be required to file an updated FRS within six months of each IRP filing, rather than waiting for IRP acknowledgment, with any

request for waiver supported by evidence and submitted within two months of the IRP filing. *Id.* Finally, Staff recommended that future FRS filings provide additional analysis and documentation regarding reserve-driven resource additions, use of current operational data, coordination of integration charge and IRP-based avoided cost rate development, treatment of behind-the-meter resources, renewable penetration assumptions, QF renewal treatment, reliability target selection, and the costs associated with downward regulation reserves. *Id.* at 15. Staff believed that these recommendations would improve the accuracy, transparency, and consistency of integration charge calculations and ensure that future studies best reflect evolving system conditions and market operations. *Id.*

COMPANY REPLY

In response to Staff's recommendation to file a case to update the integration charges within six months of filing each IRP, the Company stated that its integration cost filings have historically relied on analysis already completed as part of the IRP, requiring little additional preparation. Company Reply at 2. The Company believed IRP integration cost results would be generally sufficient for QF pricing and that additional analysis would provide limited value given the relatively small impact of integration costs. *Id.* at 2-3. However, if additional analysis was required, the Company agreed that a six-month filing window after each IRP would provide adequate time to complete and submit an updated integration cost case. *Id.* at 3.

In response to Staff's recommendation that the Company provide evidence to support its position that the new resources in the preferred portfolio are not driven by reserve requirements, or alternatively, develop a method to account for reserve-related costs, the Company explained that its 2025 IRP modeled integration service through regulation reserves held on dispatchable resources. *Id.* at 3-4. Under stressed conditions, all available resources would be deployed to serve load, meaning integration reserves would not create an incremental need for new resources or associated fixed costs. *Id.* at 4. The Company also noted that operational practices, forecasting improvements, and participation in the Western Energy Imbalance Market ("WEIM") further reduce reserve shortfall risks. *Id.*

However, the Company stated that it is evaluating changes for its 2027 IRP to reflect participation in CAISO's EDAM, which includes resource sufficiency requirements and penalties for reserve shortfalls. *Id.* at 5. Under the proposed 2027 approach, reserve shortfalls would be treated similarly to energy shortfalls, potentially creating an incremental need for resources and

associated fixed costs. *Id.* The Company indicated that any resulting changes to how integration costs are reflected in planning, including possible adjustments to wind and solar capacity contributions, should also be applied consistently to Idaho QFs. *Id.* at 6.

Regarding Staff's recommendation that the Company use more historical data, including data from CAISO's EDAM, the Company explained that it did not use more recent data in this case because EDAM was not implemented until May 1, 2026, and it intends to develop a more comprehensive update reflecting EDAM operating practices. *Id.* The Company stated that, for its 2027 IRP, it plans to incorporate available EDAM data, including Imbalance Reserve Up requirements, although CAISO has only produced these values for PacifiCorp's balancing authority areas since parallel EDAM operations began in February 2026. *Id.*

In response to Staff's recommendation that the Company clarify if it intends to determine integration charges for IRP-based avoided cost rates in the same model that determines the IRP-based avoided cost rates and review the feasibility of meeting the timelines in Electric Service Schedule No. 38—Qualifying Facility Avoided Cost Procedures if both rates are determined in the same case, the Company believed that integration costs should be based on the most recently filed IRP and that a separate approval process is unnecessary. *Id.* at 7. The Company believed that this approach would be most consistent with the current IRP methodology, while noting that future IRPs may require a different approach if integration requirements are modeled dynamically. *Id.*

In response to Staff's recommendation that the Company review potential overestimation and underestimation of integration charges for behind-the-meter generation, the Company stated that it is open to further evaluation as part of its next export credit rate update due in July 2028. *Id.* at 7-8. The Company explained that behind-the-meter generation cannot be analyzed using the same forecasting methods as utility-scale resources, but preliminary information suggests customer exports may exhibit greater volatility and could warrant slightly higher integration costs. *Id.* at 8. However, the Company believed a comprehensive analysis is not currently necessary because integration costs are relatively low, expected to decline over time, and will be updated through the export credit rate process. *Id.*

In response to Staff's recommendation that the Commission direct the Company, in its next study, to examine whether behind-the-meter generation should be presented through a proxy due to lack of data to be subject to wind and solar reserve requirements and whether existing behind-the-meter resources and increases in behind-the-meter resources should be treated differently, the

Company believed that behind-the-meter wind resources are too limited to justify separate analysis. *Id.* at 9. The Company explained that while the growing amount of behind-the-meter solar may warrant additional review, the Company would recommend conducting that analysis as part of its next export credit update in July 2028 rather than the 2027 IRP. *Id.* at 9-10. The Company noted that upcoming EDAM data will be limited and evolving, and that waiting until the next export credit proceeding would allow for a more meaningful evaluation of customer export impacts and integration requirements. *Id.* at 10.

In response to Staff's recommendation that the Commission direct the Company to determine reasonable penetration levels in its next FRS that reflects the actual trend on the Company's system and explore whether a tiered structure of integration charges based on different penetration ranges should be developed, the Company stated that penetration-based tiers are unlikely to meaningfully improve the accuracy of avoided costs. *Id.* The Company explained that wind and solar penetration is driven by all system resources, not just Idaho QFs, and can be significantly affected by non-QF resource additions, contract renewals, and developments in other states. *Id.* The Company also emphasized that small QFs have minimal impact on integration requirements and that larger QFs priced under the IRP methodology already receive updated pricing every two years. *Id.* at 11. While the Company was not opposed to using tiered integration costs if future IRPs adopt them, it does not support developing Idaho-specific integration cost tiers now. *Id.*

In response to Staff's recommendation that the Commission direct the Company to determine whether QF renewals should be excluded from the preferred portfolio in the next FRS, the Company believed that the treatment of QFs in IRP modeling should be addressed through the IRP public input and review process rather than in an integration cost proceeding. *Id.* at 11-12. The Company also believed that excluding assumed QF renewals may not materially change integration requirements because similar proxy wind or solar resources could have been selected instead, resulting in comparable renewable penetration and integration needs. *Id.* at 12.

In response to Staff's recommendation that the Commission direct the Company to determine, in the next FRS, whether the reliability targets for energy supply shortfalls and reserve shortfalls should be set at a level where the resulting total loss of load does not exceed the industry threshold every year throughout the planning horizon, the Company explained that improving EDAM-based modeling may better align energy and reserve shortfall treatment in the 2027 IRP.

Id. The Company believed that its 2025 IRP could not precisely target loss-of-load reliability levels due to the timing of stochastic analysis and the difficulty of adjusting portfolios afterward, especially given the sensitivity of results to small resource changes and the complexity of high wind, solar, and storage portfolios. *Id.* at 13. The Company also believed that while portfolios should be reasonably close to reliability targets, exact calibration is limited by modeling constraints and the tradeoff between precision and timely IRP completion. *Id.*

In response to Staff's recommendation that the Commission direct the Company to address the cost issues associated with downward reserves in the next study, the Company believed that it generally has sufficient downward ramping capability within its existing resource portfolio and does not need to explicitly procure additional downward reserves. *Id.* The Company explained that wind and solar resources, including owned assets and PPAs, can rapidly reduce output and are efficiently dispatched through the WEIM, which prioritizes the most cost-effective backdown order based on market bids and production tax credit impacts. *Id.* at 14. The Company further believed that, unlike upward reserves that withhold capacity from generation, downward ramping does not prevent resources from producing unless needed, reinforcing its view that additional cost allocation for downward reserves is unnecessary. *Id.*

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 Company's Application including all submitted materials, Staff Comments, and the Company's Reply Comments. Based on our review of the record, we find it fair, just, and reasonable to approve the wind and solar integration charges proposed by the Company and reflected in Attachment A to Staff's Comments.

The record demonstrates that the Company's proposed wind and solar integration charges are based on the results of its 2025 IRP and are consistent with prior Commission directives regarding the development and updating of wind and solar integration costs.

We further find Staff's recommendations are reasonable and supported by the record. Staff identified several areas where future filings may be improved—or certain information would be useful for Staff's analysis—including the use of more recent operational data, consideration of evolving market structures, treatment of behind-the-meter resources, renewable penetration assumptions, reserve requirements, and the timing of future integration cost filings. We agree that continued review of these issues will improve the accuracy, transparency, and consistency of future integration cost studies.

At the same time, we recognize the Company's concerns. The Company explained that many of Staff's recommendations involve issues currently under evaluation as part of its ongoing resource planning processes and the implementation of the CAISO's EDAM is expected to significantly affect future modeling assumptions and methodologies. We find the Company's reasoning reasonable and acknowledge that some of Staff's recommendations may be more appropriately addressed as additional EDAM operational experience and data become available.

To ensure timely review of future wind and solar integration costs and consistency with the Company's IRP process, we direct the Company to submit subsequent FRS filings within six months of filing each future IRP. If the Company believes compliance with this timeline is not feasible or warranted under the circumstances, it may request a waiver from the Commission. Any waiver request shall explain the basis for the request and identify the proposed alternative filing schedule.

We also find that future wind and solar integration cost studies should incorporate the most recent operational data available, including data associated with CAISO's EDAM, as such information becomes available and sufficiently developed for analytical use. The Commission agrees with Staff that the use of current operational data will improve the accuracy and relevance of future wind and solar integration cost calculations.

To facilitate review of the transition to EDAM-based methodologies, we direct the Company, in its next wind and solar integration cost filing, to provide results using both the EDAM-based data and methodology and the historical data and methodology utilized in this proceeding. Providing both analyses will allow Staff and the Commission to compare results, evaluate the effects of EDAM participation on wind and solar integration costs, and maintain an appropriate baseline for future proceedings, as the Company begins to rely more heavily on EDAM-based data for its wind and solar integration cost filing.

Finally, we find that continued collaboration between the Company and Staff is necessary to address the issues identified in this case. Therefore, prior to its next wind and solar integration cost filing, we direct the Company to meet with Staff to discuss Staff's recommendations and concerns, the Company's planned methodology and assumptions, the incorporation of EDAM-based data, and any questions or concerns the Company may have regarding future compliance obligations. We believe such collaboration will help narrow issues, improve transparency, and facilitate a more efficient review of future filings.

ORDER

IT IS HEREBY ORDERED that the wind and solar integration charges proposed by the Company and reflected in Attachment A to Staff's Comments, are approved.

IT IS FURTHER ORDERED that the Company shall submit subsequent FRS filings within six months of filing each future IRP.

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 7 days after any person has petitioned for reconsideration, any other person may cross-petition for reconsideration. *Idaho Code* § 61-626.

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DONE by Order of the Idaho Public Utilities Commission at Boise, Idaho this 1st day of July, 2026.

EDWARD LODGE, PRESIDENT

JOHN R. HAMMOND JR., COMMISSIONER

DAYN HARDIE, COMMISSIONER

ATTEST:

Monica Barrios-Sanchez
Commission Secretary
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