REDACTED

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

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May 2, 2025

VIA ELECTRONIC FILING

Utah Public Service Commission
Heber M. Wells Building, 4th Floor
160 East 300 South
Salt Lake City, UT 84114

Attention: Gary Widerburg
Commission Secretary

RE: **Docket No. 25-035-10 – PacifiCorp's Semi-annual Hedging Report**
Rocky Mountain Power's Confidential Reply Comments

In accordance with the Amended Notice of Filing and Comment Period issued by the Public Service Commission of Utah ("Commission") on March 14, 2025, PacifiCorp d. b. a. Rocky Mountain Power ("the Company") submits its reply comments in response to the comments filed on April 11, 2025 by the Division of Public Utilities ("Division").

Background

As part of a general rate case in Docket No. 10-035-124, a collaborative process was initiated to discuss the Company's hedging policies and develop reporting requirements for an ongoing semi-annual hedging report to the Commission. The Company has since filed the semi-annual hedging reports for six-month periods ending June and December of each year as required. The DPU is tasked with reviewing PacifiCorp's semi-annual hedging reports for compliance and providing recommendations to the Commission. On February 1, 2022, the Company filed its hedging report for the period ending December 31, 2021 that reflected changes to the hedging practices. The changes were fully described in PacifiCorp's confidential technical conference presentation, which was held on March 29, 2022. The Company's semi-annual hedging report for the six-month period ending December 31, 2024 that was filed on February 14, 2025 is the latest hedging report filed since the Company implemented changes to its hedging practices.

Response to Division's Comments

1. ***The Company is addressing the Division's concerns regarding west-side purchasing activities in other proceedings.***

The Division discusses the fact that [redacted]. Although the Division has previously acknowledged that Utah customers benefit from the larger system and conceded to the fact that hedging take places on the west side of the system does not mean it exclusively benefits customers on the west side of the system[1], they claim it is important that the system function as a whole to maximize benefits and th [redacted].[2]

However, the Company pointed out in the 2024 general rate case proceeding (Docket No. 24-035-04), that it is making [redacted] in order to minimize costs for the overall system, to [redacted]- [redacted] and to keep free transmission capacity to respond to reliability events at times of peak demand. The monetary costs and benefits of those activities are distributed to customers through the allocation mechanisms[3], and the operational benefits manifest as reliable service.

In addition, the Division criticizes the Company's hedging program as requiring the purchase of significantly more power than is likely to be needed[4], which fails to acknowledge evidence provided in the Company's 2024 general rate case. Specifically, the Company provided evidence that this is not true when evaluating the Company's historical utilization of forward power hedge volumes[5].

2. *Various other criticisms*

The Division makes two other claims that should be addressed here: 1) that the Company does not appear to be changing its hedging strategy going forward[6], and 2) that hedging somehow reduces the level of benefit customers enjoy from energy imbalance market (EIM) participation.[7]

On the first topic, the Company assures the Division and the Commission that it is constantly re-evaluating and internally discussing changes in the market (e.g., price, instrument availability, etc.) and the regulatory landscape (e.g. CETA implementation, etc.) to inform potential future changes to its strategy and policy.

Second, the hedging strategy employed by the Company is part of what allows for participation in the EIM. To participate in the EIM, the Company is required to pass a resource sufficiency evaluation (RSE) to show that it can serve load without reliance on EIM. One of the things considered during the RSE is the existence of firm power purchases since that reduces the burden placed on generating resources, helping the Company to participate in EIM with greater frequency. In other words, those forward purchases are part of what allows EIM benefits to exist

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[1] *Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulation,* Docket No. 24-035-04, Reporter's Transcript, Re: December 16m, 2024 Phase I Hearing lines 9-11.
[2] Comments from the Division of Public Utilities at 9 ("DPU Comments").
[3] *Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations*, Docket No. 24-035-04, Phase I Rebuttal Testimony of Michael G. Wilding, lines 199 to 377 (Nov. 15, 2024).
[4] DPU Comments at 4
[5] Exhibit RMP___(MGW-2R) CONF in Docket No. 24-035-04, with accompanying testimony in Phase I Rebuttal Testimony of Michael G. Wilding, lines 420 to 452
[6] DPU Comments at 9.
[7] *Id*. at 5.

so that they may be passed along to customers. If there is a relationship between hedging and EIM benefits (which is debatable, given the vastly different time horizons impacted by each activity), the only possible logical relationship is that forward hedging makes the Company eligible to participate with greater frequency (in some measure), which increases EIM benefits for customers.

3. ***The Company has already changed the Integrated Resource Planning process to address the Division's criticisms.***

Regarding the Company's IRP, the Division criticizes the inclusion of restrictions on natural gas resources and discusses the relative load and resource position on the east and west side of PacifiCorp's system. With regard to the availability of natural gas resources, PacifiCorp's 2025 IRP included the option to add new natural gas resources on the east side of its system. This is a change from the 2021 IRP, which did not allow any new natural gas-fired resources. It is also a change from the 2023 IRP, which allowed new natural gas-fired resources but with a restricted economic life that significantly increased their effective cost. The change in the 2025 IRP was in part a result of the U.S. Environmental Protection Agency's finalized rule on natural gas resources in April 2024, which allowed operation of efficient simple cycle natural gas fired facilities up to a forty percent annual capacity factor without requiring carbon capture, hydrogen-fueling, or other expensive modifications.[8] While new natural gas-fired resources were not selected as part of the Utah 2025 IRP preferred portfolio, conversion of the existing Dave Johnston 1 & 2 units to natural gas-fired operation was selected.

With regards to the discussion of the load and resource balance, PacifiCorp notes that the east and west load and resource positions presented in the 2025 IRP reflect the physical locations of resources, and not the allocation to the jurisdictions located on the east and the west sides of the system. DPU raises concerns about resource sufficiency in and for the west. For the first time in the 2025 IRP, PacifiCorp performed separate optimizations for Oregon, Washington, and for the rest of its system, to ensure that all of the compliance requirements specific to each jurisdiction were met. Along with other jurisdiction-specific requirements, each jurisdiction was required to comply with Western Resource Adequacy Program (WRAP) requirements starting with the beginning of binding operations under that program in 2028. Because transfer capability between the east and the west is limited and not expected to increase, the preferred portfolio presented in Chapter 9 of the 2025 IRP also requires that jurisdictional compliance be met with resources in the same physical location, i.e. Oregon and Washington, and could only select from resource options on the west side of the system, while the rest of system study is limited to resource options on the east side of the system.[9] To the extent that Oregon or Washington need additional resources to meet WRAP requirements, the model is able to select what is cost-effective under their assumptions and constraints to meet those requirements. Similarly, the model selects what is cost-effective under their assumptions and constraints for the rest of the system, which are primarily economic, rather than driven by environmental standards. All of the resource selections in the 2025 IRP are assumed to be assigned to the specific jurisdictions for whom they were

[8]

[9] While California has a number of policy requirements, PacifiCorp is currently required to demonstrate compliance using system-wide portfolio results, and those requirements were not included.

selected (not including the advanced nuclear Natrium™ demonstration project which is assumed to be shared). Modifications to hedging policies and practices may be appropriate to account for WRAP compliance requirements, which are expected to begin by 2028, as well as the divergent portfolio outcomes from increasing situs-assigned resource procurement, but these changes are unlikely to impact operations in the next couple years.

4. Natural gas usage versus forecasted values.

Regarding natural gas hedges, the Division compares the actual volume of natural gas consumed to the forecast volume and concludes that the actual usage of natural gas for the period of January 2024 through December 2024, did not follow the forecasted requirement. The Division states it will continue to monitor this and look for trends over time. The Division also questions why the Company did not [redacted] due to the cost of power hedges.[10] Please note that dispatch decisions are based on spot market economics, not the price of hedges executed months or years before those dispatch decisions are made.

The Division, in their analysis, notes that "it is reasonable to expect that actual usage will vary from the anticipated requirement within a reasonable range," based on market conditions and price levels for power and gas. In addition to those drivers, it is important to remember that the Company publishes a forecast of *gas requirements*, not all gas it expects to consume in the forecast period.

For an example of why this distinction is important, consider Energy Imbalance Market (EIM) dispatch. To the extent that the Company participates in the EIM and is a net *exporter* of power, that *increases* the amount of gas (and coal) consumed during the historical period in question because the Company is generating more than is required to serve load. This can also potentially *decrease* consumption when the Company is a net *importer* of power. The EIM is a not a requirement in the same sense that serving load is, but it is something the Company elects to participate in because the net effect is a benefit to customers. That participation can materially alter the Company's actual gas consumption as compared to its forecasted requirements. In addition to the EIM, there are other factors, including changes in coal fuel availability, unseasonably mild or extreme weather, hydro conditions, and the actual spot market economics of dispatching gas plants when compared to forward gas and power prices. For all of those reasons, the actual gas consumption will never match the forecasted requirements.

In addition, the Division cites physical natural gas spot market sales over the past six months as a point of concern, opining that the current risk limit structure does not appear to be working as intended.[11] The concern voiced by the Division is not valid because the figures quoted by the Division are physical sales. [redacted]. For some sense of scale, [redacted]

[10] DPU Comments at 15.
[11] *Id.* at 14.

[redacted], [redacted]). The Company primarily [redacted]). In short, the approach to managing natural gas price and supply risk is almost always [redacted]. Forward index-priced physical purchases represent procurement of supply, but do not factor into the Company's hedge ratio. Fixed price financial purchases directly inform the Company's hedge ratio but cannot supply natural gas fired plants with fuel for generation. In other words, [redacted] It simply means that economics or operational drivers caused the Company not to require all purchased physical gas. The Division claims that the Company "has not explained how it could be hedged at 65% of the total requirement and still need to sell 5,705,628 MMBtu of excess gas purchases for generation.[12]" That explanation is straightforward: [redacted] the Company has engaged in. This is not so much a criticism of the Company's hedge program as it is a misunderstanding of the Company's hedge program. In addition, the Company was a [redacted], strongly indicating that sales are representative of normal day-to-day variations in fuel requirements, not systematic over-supply.

The Division indicates that "the opacity of the trading and hedging programs makes effective review difficult[13]," but their complaint stems from the fact that the Company does not track the reason for individual daily decisions made in the past regarding physical natural gas sales. The Division seems to place a high value on this type of review because [redacted]. However, as noted above, that is simply incorrect. As it relates specifically to spot market purchases and sales, those tend to happen on different days or at different locations and under different market conditions, absent some operational driver (e.g., loss of a generating unit). As purchases and sales happen on different days, and as different days have different prices, price equivalence should not be expected.

5. *The Division's criticism of the Company's load forecast update process.*

The Division goes on to criticize the frequency of the Company's load update, noting that the load forecast was the same between the June Semi-Annual Report and the December Semi-Annual Report.[14]

First, the 2025 prompt year forecast is updated twice per year, which is sufficient for two primary reasons: first, the hedge ratio requirements increase over time, meaning that most of the requirement exists in the prompt 12 months (this is particularly the case because the power hedging requirements only extend 18 months into the future); and second, the longer-term (year

[12] *Id.*
[13] *Id.* at 14-15.
[14] *Id.* at 15.

2 and beyond) annual update is scheduled that way because of the time-consuming nature of the load forecast process itself, which has somewhat muted effects on the Company's hedging requirements or activities because of the relatively low hedge ratio requirements in month 13 and beyond.

Informal inquiries on this matter may be directed to Max Backlund at (801) 220-3121.

Sincerely,

Jana Saba

Jana Saba
Director, Regulation and Regulatory Operations

Enclosures

CC: Service List

CERTIFICATE OF SERVICE

Docket No. 25-035-10

I hereby certify that on May 2, 2025, a true and correct copy of the foregoing was served by electronic mail to the following:

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