REDACTED
Rocky Mountain Power
Docket No. 23-035-01
Witness: Jack Painter

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Response Testimony of Jack Painter

December 2023

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

Q. Are you the same Jack Painter who submitted direct testimony on behalf of the Company in this proceeding?

A. Yes.

PURPOSE OF TESTIMONY

Q. What is the purpose of your response testimony?

A. My testimony responds to certain issues raised by the Utah Division of Public Utilities ("DPU") in its energy balancing account ("EBA") Audit Report and by Daymark Energy Advisors ("Daymark"), on behalf of the DPU. Specifically, I discuss the DPU's request to retain the ability to propose disallowances for calendar year 2022 EBA costs included in the EBA the Company will file May 1, 2024 for calendar year 2023 costs ("2024 EBA"). I address the DPU's recommendation for certain workshops and additional information in the 2024 EBA. I present a correction to the replacement power cost calculation presented by Daymark for the proposed adjustments related to thermal generation plant events. I also provide an update to the Federal Energy Regulatory Commission ("FERC") proceeding regarding FERC account 509 that was raised in my direct testimony.

Q. Are any other Company witnesses filing testimony in response to issues raised by the DPU and Daymark?

A. Yes. Company witness Mr. Brad Richards provides testimony in response to the proposed adjustments associated with certain generating plant events. Mr. Richards explains that the Company was prudent in its operations and management of its thermal generation plants. Additionally, Company witness Mr. Douglas R. Staples provides testimony responding to the DPU's recommended adjustment to the recovery in this case for power physical trades and provides support for the Company's trading and hedging activities and explains that the Company was prudent when engaging in the hedging transactions.

PROPOSAL FOR PRESERVING ABILITY TO REVIEW CALENDAR YEAR 2022 EBA COSTS IN FUTURE EBA FILING

Q. What does the DPU recommend regarding its review of the dispatch of the Company's coal generating fleet?

A. The DPU claims that during extreme weather events and drought conditions the Company did not economically dispatch its coal facilities to displace high-cost natural gas and purchased power prices. The DPU notes that the Company is preparing a report on the economics of its coal dispatch at the direction of the Idaho Public Utilities Commission ("IPUC") as part of the annual Energy Cost Adjustment Mechanism ("ECAM") for 2022. At the conclusion of the prudency review, the IPUC preserved the ability to adjust the 2022 ECAM during the following ECAM period. The DPU recommends the Public Service Commission of Utah ("Commission") follow a similar process to allow additional time to review and requests the Commission allow parties to propose adjustments for calendar year 2022 EBA costs in the Company's 2024 EBA filing.

Q. Does the Company agree with the DPU's assertion that it did not prudently dispatch its coal facilities during calendar year 2022?

A. No. The Company generated 297 gigawatt-hours ("GWh") more than its forecasted coal generation and at a lower cost of $20.47 per megawatt-hour ("MWh") than its forecasted cost of $21.45/MWh. The increased generation combined with the lower $/MWh cost resulted in a decreased total coal cost of $22 million when compared to the forecast.

Q. Were there any factors outside the Company's control regarding its coal supply?

A. Yes. Toward the end of 2022, due to conditions outside of the Company's control, coal supply issues and force majeure claims causing delivery shortages began to impact the dispatch at Utah's Hunter and Huntington coal-generating plants. The operating mines in Utah's Book Cliffs and Wasatch Plateau coal fields experienced production difficulties due to a variety of geological, logistical, and financial challenges. Additionally, there was a mine fire at American Consolidated Natural Resources' Lila Canyon mine in September 2022. In recent years, the Lila Canyon mine has accounted for more than 25 percent of Utah's coal production.

Q. How does the Company's system respond to the coal supply limitations?

A. The Company operates its system on a least cost economic dispatch model. Simply put, it dispatches its lowest cost resources first followed by its more expensive resources in an increasing order. To further illustrate how this impacted coal and natural gas dispatch, Figure 1 below depicts the MWh variance from Base net power cost ("NPC") by month for the Company's coal and gas generating resources, and Table 1 below depicts forecast and actual 2022 MWh for coal generation, gas generation, total

Company load, and wholesale sales with variances by month. Figure 1 shows that the Company operated its coal generating resources above its forecasted levels from April through October and then only decreased dispatch in November and December when the coal supply constraints limited these resources. Correspondingly, the Company was able to increase its gas generating resources in November and December by approximately the same MWhs to replace the coal generation. Even with higher natural gas prices in 2022, Company owned gas-generating plants were still least-cost dispatch resources on average and more economic than market purchases. Additionally, actual Company load was greater than forecasted load in November and December and the Company's system was able to respond with a reduction to market sales. All these operations indicate that the Company has managed its resources in a prudent and least cost economic manner.

Confidential Figure 1

[redacted]

Confidential Table 1 – CY 2022 Actual vs Forecast Variances

[redacted]

Q. Are the coal stockpile levels at the Company's Utah plants reviewed by the DPU and reported to the Commission, and were the Company's actions necessary to maintain an appropriate stockpile at these plants?

A. Yes. Rocky Mountain Power's fuel inventory policies are audited annually by the DPU who reports to the Commission.[1] Because of the coal supply constraints that were identified above, Rocky Mountain Power had to take action to maintain the minimum stockpile reliability target of 45 days inventory. Accordingly, and based upon industry standard practice regarding the dispatch of fuel limited resources (such as hydroelectric resources), Rocky Mountain Power calculated the dispatch price for the fuel limited Hunter and Huntington units to maintain minimum stockpile reliability coal inventories and secure availability for the benefit of customers during critical periods. The dispatch

[1] The DPU in their report noted these coal inventory difficulties in their report: "The Lila Canyon mine fire has impacted Utah's coal production. The Lila Canyon mine accounts for around a quarter of Utah's coal production.8 Although the fire has been put out, production at the mine may not begin until late 2024 or early 2025. This and other factors reduced Utah's coal production in the past year, thus lowering supply, increasing prices, and limiting the ability to cost-effectively restore inventory)." *Division of Public Utilities' Audit of PacifiCorp's 2022 Fuel Inventory Policies and Practices*, Docket No. 23-035-14 Memorandum at 6-7 (Mar. 29, 2022).

price for these units was calculated, to ensure an adequate coal stockpile, at $50-$70 per MWh at Hunter in September and later in November at Huntington. By the end of 2022, the price was recalculated to approximately $90 per MWh. The higher dispatch prices ensure the optimization models do not lower inventory to unacceptable levels. The Company's decision to calculate the dispatch price based on the economics of fuel-limited resources reflect its commitment to upholding reliability standards, and ensuring the availability of coal units when they are most needed. Although this calculation rendered the units less economically favorable to dispatch within the operational optimization model in late 2022, it was necessary to maintain a prudent coal stockpile level in the aftermath of the unprecedented force majeure claims made by the units' two coal suppliers, and to ensure reliability during high-demand periods.

Q. Did the DPU have adequate time to review the Company's coal dispatch to propose a timely adjustment to calendar year 2022 costs in this docket?

A. Yes. The company filed its annual EBA for the 2022 deferral period on May 1, 2023, and Parties have had ample time to review and audit the Company's filing. Besides conducting its own audit, the DPU has also contracted Daymark to assist with its audit. There is no reason why the DPU could not have reviewed this issue during the time between the filing on May 1 and its audit report on November 7.

Q. How is the process in the Utah EBA different from the process of the Idaho ECAM?

A. The Company files its Idaho ECAM annually on April 1st and the proceeding concludes with rates effective on June 1st. While some of the review begins prior to filing, the entire formal proceeding is complete in two months. So it makes sense that the IPUC would require additional time to study the Company's coal dispatch. In Utah, the EBA proceedings are 300 days, and the DPU has 190 days to conduct its audit during the formal proceeding.

Q. Does the Company object to providing the DPU a copy of the study that is being prepared for IPUC?

A. No. The Company intends on providing the study once completed to the DPU and any party who has intervened in a relevant regulatory proceeding and signed any required non-disclosure agreements, if applicable.

Q. Could the DPU and other intervening parties attempt to use the results of the study to propose adjustments to the 2024 EBA?

A. Yes. However, the DPU and other parties should only be able to propose adjustments that relate to calendar year 2023 deferred costs that are presented in the 2024 EBA. The Company is only opposed to the DPU's request to be able to preserve the ability to propose adjustments to costs related to calendar year 2022 deferrals in the 2024 EBA.

Q. Why should the Commission reject the DPU's recommendation to preserve the prudence review of CY 2022 costs in the 2024 EBA?

A. Utah Code Ann. § 54-7-13.5(2)(l)(ii) requires the Commission to issue a final order establishing and fixing an electrical corporation's balancing account "before the expiration of 300 days after the day on which the electrical corporation files a complete filing." The Commission recently denied an Application by the Company to implement a procedural schedule that did not comply with the 300-day statutory requirement stating:

> In principle, we find RMP's Application, and DPU's recommendation for its approval, reasonable and in the public interest. However, we cannot approve a

> process that is, on its face, contrary to law. As DPU noted, the Application contemplates an EBA filing on or about March 15 and an order on or about February 21 of the following year. This timeframe exceeds the period the law requires the PSC to issue a final order.[2]

Q. Has the Commission recently raised additional concerns about its ability to issue a decision that extends the review of EBA costs to a future date beyond the 300-day statutory period?

A. Yes, in the Company's most recent EBA order, the Commission provided some additional information specific to the Utah Association of Energy Users' ("UAE") recommendation that recovery for certain outages be deferred pending a final resolution of the issue:

> With respect to UAE's request the PSC condition RMP's recovery for the Aeolus Outages pending a "final resolution of this issue," UAE fails to identify the legal authority under which it asks the PSC to make such an order, what would constitute such a resolution, or any particular process by which the PSC would revisit the issue in the future. Any litigation arising out of the Aeolus fire could take many years to resolve, and the PSC believes serious legal questions exist as to whether the PSC conditioning RMP's recovery on uncertain developments well into the future would constitute a lawful exercise of the PSC's jurisdiction. The PSC declines to invent such a remedy.[3]

The DPU is seeking a very similar remedy as UAE. They are attempting to condition recovery of the costs included in this EBA because of a report that is filed in another jurisdiction and extend the issue into the 2024 EBA, when they have had ample time and opportunity to review those costs in this proceeding.

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[2] *Rocky Mountain Power's Application for Approval of its Proposed Energy Cost Adjustment Mechanism,* Docket No. 09-035-15, Order at 4 (Feb. 24, 2022).

[3] *Rocky Mountain Power's Application for Approval of the 2022 Energy Balancing Account,* Docket No. 22-035-01, Order at 28 (Jan. 9, 2023).

Q. Has the Company provided sufficient evidence to explain the coal dispatch constraints in this proceeding?

A. Yes. Even though the DPU has provided minimal explanation of its concerns related to the coal dispatch of the Company's units in 2022, this testimony provides enough evidence to describe the difficulties in maintaining coal stockpiles for the Company's Utah coal plants in 2022 and the associated impact on coal generation that occurred. The Company's actions were prudent and there is no factual basis for the Commission to conclude that additional review or adjustments to the requested recovery are warranted.

ADDITIONAL WORKSHOPS AND INFORMATION

Q. Please describe the DPU's request for additional workshops and information for the 2024 EBA filing related to its review of the dispatch of coal resources.

A. The DPU has requested a series of workshops and certain information around the Company's process for forecasting power costs in the Aurora model. Additionally, they have requested certain information on the forecasted and actual generation at each plant and an explanation for variances in forecasted generation greater than 10 percent from the forecast on a monthly and annual basis.

Q. Are these recommendations familiar to the Company?

A. Yes, these are provisions that the Company has agreed to in the Company's most recent Oregon Transition Adjustment Mechanism ("TAM") proceeding.[4]

[4] *In the Matter of PacifiCorp d/b/a Pacific Power, 2024 Transition Adjustment Mechanism*, Docket No. UE 420, Order No. 23-404, Appendix A at ¶¶14-15 (Oct. 27, 2023).

Q. Is the Company willing to provide additional information to assist the DPU in its review of the dispatch of coal resources in the next EBA?

A. Yes. The Company is producing this information for the TAM and can provide it in the EBA. Some of this information is already contained in the existing standard data requests that are provided with the Company's initial EBA filing. Any information that is not already contained in those filings will be provided in the initial application.

However, regarding the requested workshops on Aurora, the Oregon TAM proceeding deals with the forecasts of NPC, and the workshops requested by the DPU related to Aurora are specifically designed to address the NPC forecast. The EBA proceedings do not use forecast NPC like Oregon. In Utah, Forecast NPC are typically used in the context of a general rate case to set the base NPC for the test period. The Company is not opposed to holding these workshops for the DPU but would recommend that they be requested in connection with the next general rate case and not in conjunction with the 2024 EBA.

REPLACEMENT POWER COSTS

Q. Please describe Daymark's proposed adjustment for generation plant events.

A. Daymark recommends reducing NPC from the EBA by $778,683, including interest, on a Utah allocated basis associated with thermal plant events on the basis that the Company acted imprudently. Daymark's adjustment consists of $753,447 for the replacement power costs and $25,235 in interest.

Q. Does the Company agree these proposed adjustments to the EBA recovery due to the generation plant events are warranted?

A. No. Company witness Mr. Brad Richards responds to the merits of Daymark's proposed adjustments and provides support for the Company's position that plant operations were prudent.

Q. Did you review Daymark's calculation for the replacement power costs with the generation plant events?

A. Yes.

Q. Notwithstanding the Company's objection to the proposed adjustments, does the Company agree with Daymark's calculation of the replacement power costs?

A. The Company agrees with Daymark's calculations relating to the thermal outage at its Craig generating plant but disagrees with Daymark's calculations relating to the thermal events at its Dave Johnston generating plant. Specifically, Daymark treated their calculations for the Dave Johnston event as outages at the plant, but the events were derates to the units, not complete outages. This affected Daymark's calculation for the replacement power costs because the MWhs were calculated based upon a complete outage and not the derated MWhs. Once this correction is made, the Company agrees with the remaining aspects of Daymark's calculations.

Q. What is the impact to the replacement power costs adjustments proposed by the DPU after making the correction?

A. Table 2 below shows the impact to the DPU's proposed adjustments. Detailed calculations for these corrections are provided in confidential workpapers provided with this response testimony.

Table 2

Derate	DPU Calculated Total	DPU Calculated EBA Allocated	RMP Calculated Total	RMP Calculated EBA Allocated
DJ 3	$ 123,306	$ 54,817	$ 17,217	$ 7,654
DJ 1	$ 491,785	$ 218,628	$ 129,159	$ 57,419
DJ 2	$ 526,778	$ 234,184	$ 204,523	$ 90,923
Total	$ 1,141,869	$ 507,629	$ 350,898	$ 155,995
Interest		$ 18,989		$ 5,735
Total DPU Proposed Adjustment		$ 526,618		$ 161,730

FERC ACCOUNTING UPDATES

Q. Did FERC issue its decision with respect to FERC account 509?

A. Yes. On June 29, 2023 the FERC posted a final ruling Order No. 898 on Accounting and Reporting Treatment of Certain Renewable Energy Assets in Docket No. RM21-11. These changes become effective January 1, 2025. The Company is still interpreting how the order applies to its accounting treatment of certain costs approved for deferral in the EBA.

Q. Does the Company agree to update Electric Service Schedule No. 94 ("Schedule 94") when it files the 2024 EBA for the list of approved accounts?

A. Yes. The Company will update the list of accounts in Schedule 94 for the recent FERC decision, if applicable, along with general updates as recommended by Mr. Smith.

CONCLUSION

Q. What is your recommendation to the Commission?

A. The Company requests the Commission approve the Company's request to recover $175,029,815 as requested in its initial application.

Q. Does this conclude your response testimony?

A. Yes.