–BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH–

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER TO INCREASE THE DEFERRED EBA RATE THROUGH THE ENERGY BALANCING ACCOUNT MECHANISM	))))))))	**DOCKET NO. 24-035-01** **Exhibit No. DPU 1.0 DIR** **Direct Testimony and Exhibits** **Gary Smith**

FOR THE DIVISION OF PUBLIC UTILITIES

DEPARTMENT OF COMMERCE

STATE OF UTAH

Direct Testimony of

Gary Smith

November 5, 2024

CONTAINS CONFIDENTIAL EXHIBITS - SUBJECT TO UTAH PUBLIC SERVICE COMMISSION RULE 746-1-602 and 603

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INTRODUCTION

Q. Please state your name, employer, and business address.

A. My name is Gary Smith. I am employed by the Utah Division of Public Utilities (Division), State of Utah. My business address is 160 East 300 South, Salt Lake City, UT 84114.

Q. Briefly outline your education background.

A. I am a Technical Consultant for the Division and have testified before the Public Service Commission of Utah (Commission) on energy, telecommunications, and water related matters. I received a Bachelor of Science degree in Economics from the University of Utah.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Division of Public Utilities.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to summarize the Division's audit findings for Rocky Mountain Power's (Company) Energy Balancing Account (EBA) for the period January 1, 2023, through December 31, 2023 (2023 EBA).

Q: Please identify the Division's witnesses for this docket.

A: The Division is sponsoring a total of three witnesses. As part of the review process, the Division hired outside consultants from Daymark Energy Advisors, Inc (Daymark). Mr. Philip DiDomenico and Mr. Dan Koehler from Daymark will discuss their review of the filing and the proposed adjustments in their testimony and report. I will present the Division's audit results, proposed adjustment, and the results of the proposed Daymark adjustment to the Company's requested EBA recovery.

Q. How did the Division conduct its audit of the EBA?

A. As stated above, the Division contracted with Daymark to review and provide recommendations and testimony on certain aspects of the Company's EBA filing. The scope of Daymark's assignment was to ascertain whether the actual costs included in the EBA filing for calendar year 2023 were incurred pursuant to an in-place policy or plan, were prudent, and were in the public interest. Daymark reviewed Actual versus Base Net Power Cost (NPC) and Production Tax Credits (PTCs); investigated plant outages; evaluated a sample of trading transactions for accuracy, completeness, and prudence; reviewed the effect of PacifiCorp's membership in the California Independent System Operator's (CAISO) Energy Imbalance Market (EIM); and reviewed the Company's risk management policies and compliance monitoring practices.

The Division's in-house staff investigated whether various NPC items were properly reconciled, booked, and supported. The Division also reviewed the Company's filing and supporting documentation for completeness and prudence. The Division's Confidential Audit Report (Confidential DPU Exhibit 1.2) includes its analysis along with the accompanying Confidential Daymark Audit Report (Confidential DPU Exhibit 2.3).

Q. Did other Division staff besides you participate in the EBA audit?

A. Yes. Four additional Division staff members reviewed and worked on various aspects of the Company's EBA filing.

REPORT SUMMARY

Q. Can you please summarize the Division's findings and recommendations?

A. Yes.

1. The Company reported its largest EBA deferral to date; the Utah allocated unadjusted 2024 EBA deferral totaled $490 million in EBA Cost (EBAC) above the base set in the 2020 general rate case (2020 GRC). This total deferred EBAC is approximately 180% more than deferral year 2022 and almost 400% more than the 2021 deferral year. After the Company's adjustments and calculated accrued interest, including the addition of $24.2 million of collection period interest during the Company's initially proposed collective period of July 1, 2024, through June 30, 2026, the net requested recovery, as filed, totaled $455 million. The Company is seeking recovery from Utah ratepayers at 100% due to the removal of the sharing band.

   The Company outlined in testimony the reasons for the increased NPC, including the following:

   1) coal fuel supply issues that began in 2022 continued through 2023 causing constraints and drastically decreased generation resulting in lower coal fuel expense compared to the 2020 Base. The lack of coal fuel supply and

generation resulted in the reliance on more expensive replacement power and lower wholesale sales;

2) increased reliance on market power purchases at higher average market prices resulted in a significant increase in market purchases, the largest component of the total deferral;

3) increased natural gas fuel expense due to higher average prices than assumed in Base; and

4) the lowest wholesale sales volumes since the Base was set in 2020.

On June 28, 2024, the Commission approved the Company's request for an interim rate, adjusted for the removal of $24.2 million of collection period interest and $826,579 for an interest rate correction. This totaled an adjusted recovery amount of $431.6 million in allowed EBAC, effective July 1, 2024. The approved interim rate resulted in an approximate 12.7% increase to Utah customers.

2. The Company's requested 2023 deferral recovery included a calculated EBAC increase of $1.4 million from the inclusion of PTCs. This increase resulted from:

1) lower than expected actual wind plant generation;

2) the actual SG allocation percent difference from the EBA deferral year and the 2020 GRC base; and

3) an increase in the federal PTC rate of $.03 per kWh of reported eligible wind plant generation from the wind plants included in the 2020 GRC.

The increase in the federal PTC rate above lowered the amount of the PTC EBA deferral, benefiting Utah ratepayers. Without this unforeseen change the amount of PTC EBAC allocated to Utah ratepayers would be higher than the $1.4 million the Company is seeking to recover. The 2023 deferral year was the third year with PTCs included in the EBA and the third year of unrealized wind generation. As detailed in Daymark's report, the under-performance of PTCs increased the Company's 2023 deferral recovery by an estimated $22 million.

3. As presented by Company witness Jack Painter, the Company changed the EBA deferral calculation in its application by adding expenses associated with export credits from Electric Service Schedule No. 137 - Net Billing Service for customer-owned generators. The Schedule 137 program enables eligible customers to offset part or all of their own electrical requirements with self-generation and receive export credits for energy fed back to the electric grid. The program was approved by the Commission in Docket No. 17-035-61, becoming effective October 31, 2020.

In April 2023, the Company started recording these Schedule 137 costs in FERC account 555. The 2023 total, excluding interest, was $8.9 million. Of this $8.9 million, $4,295,135 was incurred and recorded in the deferral year 2023 and $4,703,793 was recorded in December 2023 for the prior period from January 2020 through December 2022.

The Company's request to recover $4.7 million with interest, in Schedule 137 costs for the prior periods January 2020 through December 2022 are not the result of any difference in operating and accounting periods. The reason for the Schedule 137 cost recovery now is simply because the Company has not yet recovered them and mistakenly did not include them in the proper accounts in prior periods. This is insufficient justification for recovery in periods for which rates have already been finalized.

The Division recommends the removal of approximately $4.8 million (including interest) in Schedule 137 costs incurred in the years prior to the 2023 deferral year.

4. Since 2021, the Division has noted a concerning trend in the annual EBA deferral size due mostly to increases in power physical purchases as shown in DPU TABLE 2.

DPU TABLE 2 – Historical Summary

Calendar Year	Docket Number	EBA NPC Recovery Amount	Total Purchased Power
2023	24-035-01	**$455,000,000**	**$622,273,276**
2022	23-035-01	**$175,029,815**	**$424,019,049**
2021	22-035-01	**$90,617,662**	**$726,339,860**
2020	21-035-01	$6,606,074	$283,265,438
2019	20-035-01	$36,820,057	$300,488,992
2018	19-035-01	$23,877,352	$305,853,371
2017	18-035-01	$2,766,676	$267,628,958
2016	17-035-01	($6,542,837)	$216,498,040
2015	16-035-01	$18,948,273	$250,989,596
2014	15-035-03	$30,871,465	$247,568,821
2013	14-035-31	$28,339,553	$281,219,307
2012	13-035-32	$17,394,963	$241,973,377
2011	12-035-67	$29,286,005	
2010	10-035-124		

Most of these power physical purchases occur on the West side of the system and are unlikely to meaningfully serve Utah load. The Company has not shown that the transmission resources it holds are sufficient to move this power to Utah loads during the times for which it was procured. Additionally, the need for such a large amount of purchases is, at least in part, the product of past planning failures. The Company's decisions not to model proven resource types and focus planning on other priorities[1] have largely limited its procurement activity to intermittent resources, leaving it to rely on more expensive hedging market purchases during key hours and is a major driver of

[1] See Order, Docket No. 21-035-09, PacifiCorp's 2021 Integrated Resource Plan, at 5-8; Order, Docket No. 19-035-02, PacifiCorp's 2019 Integrated Resource Plan, at 25-26.

the 2023 deferral. It is buying market products ill-suited to its needs because it failed to properly consider and procure the resources required to meet loads. For the Utah allocated power physical trades that settled in 2023; the west side of the system accounted for approximately 90% of these market trades. The observed disparity of the volume of purchases for PAC West indicates a level of market purchases that are not likely to benefit PAC East ratepayers proportionate to their share of the costs and should be removed from the costs allocated to Utah ratepayers.

To estimate the amount of market purchases not likely to benefit Utah ratepayers, the 2023 PAC West power physical sales were subtracted from the power physical purchases resulting in a recommended Net adjustment of $129,777,380. These market purchases do not appear to meaningfully serve Utah's load and should not be allocated to Utah ratepayers.

5. The Division provided Daymark with a scope of work to perform. The results of its review are provided in Daymark's separately issued Testimony, Executive Summary, and 2023 EBA Audit Report.[2]

Based on its report, Daymark recommends a $20.2 million reduction, including accrued interest, to the Company's requested deferral on a Utah allocated basis, incorporating:

[2] Daymark Exhibits 2.0, 2.2, and Confidential Exhibit 2.3.

a) $0.8 million decrease to EBAC, including interest, for replacement power losses from 5 avoidable outages at the Naughton, Dave Johnson, and Craig plants.

b) $19.4 million decrease to EBAC, including interest, for the removal of Washington Climate Commitment Act (WA CCA) purchases to comply with a state-specific initiative as described in Daymark's report.

CONCLUSION

Q. Can you please summarize the Division's recommended total deferral?

A. Yes. The Division adopts Daymark's total of $20.2 million in Utah allocated adjustments and accrued interest.

The Division recommends reducing the Company's proposed recovery of $455 million by $178.2 million, or an additional $154.8 million from the interim rate approved amount, resulting in a recommended adjusted total recovery of $276.7 million, as follows:

May 2024 Requested Deferral	$454,953,425
2023 Accrued Interest Correction Adjustment	$826,579
Removal of Forecast Interest - July 2024 - June 2026	($24,201,822)
Interim Ordered Recovery (subject to adjustment and true-up)	$431,578,182
Total Outage Adjustment	($784,003)
Total Outage Adjustment - Accrued Interest	($30,766)
Total WA CCA Adjustment	($18,482,085)
Total WA CCA Adjustment - Accrued Interest	($931,275)
Total Sch 137 Prior Period Adjustment	($4,703,793)
Total Sch 137 Prior Period Adjustment - Accrued Interest	($126,926)
Total West Side Hedging Adjustment	($129,777,380)
Net Adjustment (Post Interim Rate)	($154,836,228)
Net Adjusted DPU Total Recommended Recovery	**$276,741,954**

Q. Does this conclude your testimony?

A. Yes.