ENERGY BALANCING ACCOUNT AUDIT FOR ROCKY MOUNTAIN POWER FOR CALENDAR YEAR 2024 (DOCKET NO. 25-035-01)

PUBLIC EXECUTIVE SUMMARY

NOVEMBER 5, 2025

PREPARED FOR

Division of Public Utilities
State of Utah

PREPARED BY

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I. EXECUTIVE SUMMARY

In its Corrected Report and Order in Docket No. 09-035-15 issued March 3, 2011 ("EBA Order"), the Public Service Commission of Utah ("Commission") approved the implementation of the Energy Balancing Account ("EBA") to recover the differences between Rocky Mountain Power's ("RMP"), a business unit of PacifiCorp ("PacifiCorp" or the "Company"), actual EBA costs and approved forecasted ("Base") EBA costs established in the general rate case ("GRC") or cases establishing rates during the EBA deferral period. The Commission found in its EBA Order that an EBA mechanism as modified by the Commission was in the public interest and would result in rates that were just and reasonable.

On May 1, 2025, RMP filed a request to recover approximately $471.6 million in deferred EBA costs incurred during the 12-month Deferral Period from January 1, 2024, through December 31, 2024.[1] RMP's request represents the net of three components, including one credit and two costs, as well as interest accrued through June 30, 2026. The request is summarized in Table 1 of the direct testimony of Mr. Painter, which is reproduced in Figure ES-1 below. The credit component is $24.9 million for special contract customer adjustments. The cost components in the application are $24.2 million related to EBA costs and a $9.2 million adjustment for Utah situs resources. Interest accruals add $18.5 million to the total requested EBA recovery. This EBA filing included four new components: a rollover of $0.24 million from the 2023 EBA collection true-up, a $24.2 million credit of the 2024 EBA final order, a credit of $51 thousand from Electric Vehicle Infrastructure Program Revenue, and a credit of $397 thousand from the 2023 Production Tax Credits update. All components represent Utah-allocated amounts, and there is no sharing band.

[1] Application (May 1, 2025).

Calendar Year 2024 EBA Deferral		Exhibit RMP___(JP-1) *Reference*
Actual EBA ($/MWh)	$ 37.05	*Line 6*
Base EBA ($/MWh)	18.81	*Line 12*
$/MWh Differential	**$ 18.24**	
Utah Sales (MWh)	26,070,633	*Line 5*
EBA Deferrable*	$ 474,911,772	*Line 14*
Special Contract Customer Adjustment*	(24,903,951)	*Line 17*
Utah Situs Resource Adjustment*	9,220,126	*Line 18*
Total Deferrable	$ 459,227,947	*Line 19*
2023 EBA Collection True-Up	$ 238,367	*Line 25*
2024 EBA Final Order Adjustment	(24,244,080)	*Line 26*
Interest Accrued through December 31, 2024	12,324,881	*Line 27*
Interest Accrued January 1, 2025 through March 31, 2025	5,995,373	*Line 29*
Interest Accrued April 1, 2025 through June 30, 2025	6,144,341	*Line 30*
Interest Accrued through Rate Effective Period July 1, 2025 through June 30, 2026	12,376,556	*Line 31*
EVIP Revenue	(51,052)	*Line 24*
2023 PTC Update	(397,024)	*Line 23*
Requested EBA Recovery	**$ 471,615,308**	*Line 32*

** Calculated monthly*

Figure ES-1. Summary of Calendar Year 2024 EBA Deferral Calculation[2]

Daymark Energy Advisors ("Daymark") was retained by the Utah Division of Public Utilities ("Division") to assist in reviewing RMP's application to increase the deferred EBA rate through the EBA mechanism in Docket No. 25-035-01. The Company is requesting approval to recover $471.6 million in deferred EBA costs covering the differences between EBA costs incurred in the calendar year 2024 and Base EBA costs collected in rates during that same period. The scope of our assignment was to ascertain whether the actual costs included in the EBA filing were incurred pursuant to an in-place policy or plan, were prudent, and were in the public interest. This report presents the results and the conclusions from that review. This review was similar to reviews that we performed for the Company's application to approve rate changes to recover (or refund) deferred EBA costs incurred at the end of 2011 presented in Docket No. 12-035-67, calendar year 2012 presented in Docket No. 13-035-32, calendar year 2013 presented in Docket No. 14-035-31, calendar year 2014 presented in Docket No. 15-035-03, calendar year 2015 presented in Docket No. 16-035-01, calendar year 2016 presented in Docket No. 17-035-01, calendar year 2017 presented in Docket No. 18-035-01, calendar year 2018

[2] Direct Test. of Jack Painter at 4, Table 1.

presented in Docket No. 19-035-01, calendar year 2019 presented in Docket No. 20-035-01, calendar year 2020 presented in Docket No. 21-035-01, calendar year 2021 presented in Docket No. 22-035-01, calendar year 2022 presented in Docket No. 23-035-01, and calendar year 2023 in Docket No. 24-035-01.

This Executive Summary does not contain any confidential information. The remainder of this report explains the basis for our conclusions and contains significant amounts of confidential information provided by RMP. The full report is available to parties that have signed the appropriate non-disclosure agreements to review material RMP has deemed confidential.

The Division has conducted a parallel review and analysis of the EBA deferral filing. Division staff will issue a report summarizing the results of its review. This report summarizes only the results of Daymark's review and analysis. Thus, the results contained in this report complement the work done by Division staff.

Actual vs Base EBA Costs

EBA Costs ("EBAC") are composed of Utah-allocated net power costs ("NPC") net of Utah-allocated wheeling revenues and production tax credit ("PTC"). Actual EBAC was higher than Base EBAC by $18.24/MWh for the deferral period.[3] That difference was multiplied by Utah sales of 26,071 GWh to obtain the EBA deferrable amount of $474.9 million, which is the main driver of RMP's EBA deferral request. Daymark's assignment included reviewing this specific variance to understand the underlying drivers of the difference and to ensure that differences can be explained reasonably. We do not consider forecast "accuracy" to be a material issue in this review but rather focus on the factors that are within PacifiCorp's control. Specifically, we reviewed the drivers of the difference between Actual and Base for two EBAC components: NPC and PTC.

The primary drivers of this variance were higher purchased power expense ($820 million), increased natural gas expense ($273 million), and lower wholesale sales revenues ($116 million). Coal fuel expense offset these increases, declining by $75 million relative to Base. Additional increases of $32 million were attributed to wheeling and other expenses. These combined effects resulted in the $1.167 billion increase in NPC above Base, which is subject to EBA treatment and recovery.

PTCs are included in the EBA calculation based on the Company's 2020 General Rate Case filing in Docket No. 20-035-04. PTCs are per kWh credits for all or a portion of

[3] *Id.*

generation from certain Company-owned wind facilities that offset federal income taxes, reducing EBAC.

The Company's PTC-eligible wind facilities generated less energy (and correspondingly fewer PTCs) than expected in 2024, increasing the EBA deferral request by approximately $20 million. Annual variability is to be expected, but over a longer period of time, under-performing years should be balanced by years with higher production and more positive actual PTC results. With more than four years of production history logged now for most of the Company's repowered wind projects, the track record has been consistently below RMP's P50 estimates presented at the time of Commission approval of the projects. The Company's economic analysis supporting regulatory approval for the repowering projects relied heavily on P50 production estimates that were either overstated or failed to adequately consider risks of underperformance. Such risks should not be borne solely by ratepayers. We recommend the Commission strongly consider ways to share this risk more equitably in future proceedings.

Outages

One of our tasks was to review and assess actual plant outages to ensure that these outages and their cost impact on the EBA charge were appropriate. We examined the information provided in filing requirements and conducted additional discovery.

Daymark reviewed the thermal, wind, and hydro outage data RMP provided in the EBA filing and the supporting documentation. Further documentation was sought for a select number of outages based on the narrative description provided. After reviewing the filing requirements and data request responses, we found no reason to adjust the EBA costs because of outages. However, further review of specific hydro, thermal, and wind outages was performed.

Our review of forced outages, maintenance outages, and extended planned outages at PacifiCorp's wind, thermal, and hydro plants during the EBA deferral period identified 17 outage events (8 thermal, 7 hydro and 2 wind) that warranted further investigation to determine whether they unnecessarily increased Company-wide NPC. The Company's responses to data requests requesting additional information about these outages were deemed sufficient to determine that these outages were not due to Company imprudence.

Natural Gas & Power Transactions

Between 2021 and 2024, PacifiCorp engaged in tens of thousands of transactions on a system-wide basis for natural gas and electricity that settled in the 2024 EBA deferral period. The costs or proceeds of these transactions flow into NPC. The transactions fall into three broad categories: hedging, system balancing, and "other." Transactions are also classified as either physical or financial depending on whether physical delivery is involved.

We developed a sample of 46 broadly representative transactions (including 38 transactions related to PacifiCorp's hedging program). For the sample transactions, we submitted detailed data requests for initial data, as well as several targeted follow-up sets. The data requests sought information that would shed light on why the Company agreed to certain transactions, how the terms of each deal fit in with the Company's market view at the time, and whether each deal conformed to the Company's risk management and corporate governance policies.

Based on our review of the natural gas sample transactions and the supporting information provided to us, we find no reason at this time to adjust the EBA or NPC for the sample natural gas transactions reviewed. Our recommendation is conditioned on the expectation that improved commercial objective documentation in Docket No. 24-035-10 will make the Company's reasoning for future discretionary trades possible to review. The Division and Daymark have been working collaboratively with the Company to improve the quality and robustness of the Company's contemporaneous documentation of trade purpose through enhanced Commercial Objective Reports ("COR") and other records. New documentation based on this collaboration was not produced before late 2024, minimizing its impact on our review of transactions in this EBA.

As the index-priced market continues to evolve, we reiterate our recommendation from last year that the Company should aggressively seek options for index-priced products, carefully evaluate their advantages and disadvantages against fixed price products, and document reasons for choosing either product to ensure physical supply needs while balancing financial hedging strategy.

Based on our review of the power physical transactions and supporting information provided to us, we found ten transactions executed in violation of corporate governance policy that are not demonstrated to be reasonable or prudently incurred costs. We recommend an adjustment of EBAC to remove $18.9 million (total Company) in hedging losses associated with three of these trades. We recommend that RMP's requested recovery of deferred EBAC should be reduced by $9,018,316 on a Utah-allocated basis, including interest.

We further recommend that the Company should report to the Commission on progress made in improving its pre-approval and independent governance review process. The Company reports that it has taken proactive steps to improve transparency and generate weekly reviews and reports by the Risk Management group to ensure compliance and appropriate documentation is maintained The Company must build on this progress and continue training efforts and rigorous detection mechanisms to ensure that a similar situation does not occur again.

We are encouraged by the progress that the Company has made in finding available index-priced forward deals, which saved ratepayers tens of millions of dollars in this EBA deferral period relative to the same deals made as fixed price transactions. The Company should continue exploring opportunities for index-priced forward transactions and carefully weigh these options against fixed price options when physical and financial hedging needs diverge.