ENERGY BALANCING ACCOUNT AUDIT FOR ROCKY MOUNTAIN POWER FOR CALENDAR YEAR 2021 (DOCKET NO. 22-035-01)

PUBLIC EXECUTIVE SUMMARY

SEPTEMBER 21, 2022

PREPARED FOR

Division of Public Utilities
State of Utah

PREPARED BY

Daymark Energy Advisors

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 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 March 15, 2022, RMP filed a request to recover $90.6 million in deferred EBA costs incurred during the 12-month Deferral Period from January 1, 2021, through December 31, 2021.[1] RMP's request represents three components, including one credit and two costs, as well as accrued interest through April 30, 2022. The request is summarized in Table 1 of the direct testimony of Jack Painter, which is reproduced in Figure ES-1 below. The credit is $22.4 million for special contract customer adjustments. The cost components in the application are $107.6 million related to EBA costs and a $2.9 million adjustment for Utah situs resources. Interest accruals add $2.6 million to the total requested EBA recovery. All components represent Utah-allocated amounts, and there is no sharing band.

[1] Docket No. 22-035-01, Rocky Mountain Power, Application to Increase the Deferred EBA Rate Through the Energy Balancing Authority Account Mechanism, March 15, 2022.

Calendar Year 2021 EBA Deferral		Exhibit RMP_(JP-1) Reference
Actual EBA ($/MWh)	$ 23.04	*Line 6*
Base EBA ($/MWh)	18.81	*Line 12*
$/MWh Differential	**$ 4.22**	
Utah Sales (MWh)	25,523,328	*Line 5*
EBA Deferrable*	$ 107,599,353	*Line 14*
Special Contract Customer Adjustment*	(22,400,376)	*Line 17*
Utah Situs Resource Adjustment*	2,866,745	*Line 18*
Total Deferrable	$ 88,065,722	*Line 19*
Interest Accrued through December 31, 2021	1,451,080	*Line 23*
Interest Accrued January 1, 2022 through March 31, 2022	871,124	*Line 25*
Interest Accrued April 1, 2022 through April 30, 2022	229,736	*Line 26*
Requested EBA Recovery	**$ 90,617,662**	*Line 27*

** Calculated monthly*

Figure ES-1. Summary of Calendar Year 2021 EBA Deferral Calculation[2]

Daymark Energy Advisors ("Daymark") was retained by the Division to assist in reviewing RMP's application to increase the deferred EBA rate through the EBA mechanism in Docket No. 22-035-01. The Company is requesting approval to recover $90.6 million in deferred EBA costs covering the differences between EBA costs incurred in the calendar year 2021 and Base EBA costs collected in rates during that same period.[3] 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 of and the conclusions from that review. This review was similar to the review that Daymark 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 presented in Docket No. 19-035-

[2] Docket No. 22-035-01, Direct Testimony of Jack Painter, Page 3, Table 1.

[3] Docket No. 22-035-01, Rocky Mountain Power, Application to Increase the Deferred EBA Rate Through the Energy Balancing Authority Account Mechanism, March 15, 2022.

01, calendar year 2019 in Docket No. 20-035-01, and calendar year 2020 presented in Docket No. 21-035-01.

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

The Division is conducting a parallel review and analysis of the EBA deferral filing. Division Staff will be issuing a report summarizing the results of its review. This report summarizes only the results of Daymark's review and analysis. Thus, the result contained in this report should be considered as complementing the work done by Division Staff.

Actual vs Base EBA Costs

EBA Costs ("EBAC") comprise Utah-allocated net power costs ("NPC") net of Utah-allocated wheeling revenues and production tax credits ("PTC"). Actual EBAC were higher than Base EBAC for the deferral period.[4] That difference was multiplied by Utah sales to obtain the EBA deferrable amount of $107.6 million, which is the 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 drivers of difference that are within PacifiCorp's control. We reviewed drivers of difference between Actual and Base for two of the EBAC components: NPC and PTC.

Decreased wholesale sales revenue ($42 million) and increased purchased power expense ($125 million) comprise more than half of the $263 million increase in Actual NPC versus Base NPC. The decrease in sales revenue is driven by a decline in sales, but the increase in purchased power expense came despite a nearly equal *decrease* in purchase volume. Short term volatility and the need for very high-priced market purchases to serve load during times of regional supply tightness account for this. The variance from Base NPC is generally consistent with and explainable by market condition changes between the Base NPC forecast for the 2021 test period and actual conditions during the 2021 deferral period.

[4] Direct Testimony of Jack Painter, Page 3, Table 1.

PTC are included in the EBA calculation for the first time based on the Company's 2020 GRC filing in Docket 20-035-04. PTC are per kWh credits for generation from certain Company-owned wind facilities that offset federal income taxes, reducing EBAC.

We recommend an adjustment of EBA cost for two issues related to PTC. First, there is an apparent error in the Company's calculation of PTC-eligible production, undercounting 51,000 kWh of PTC-eligible production. Correcting the error adds $1,275 PTC on a Total Company basis ($1,691 tax affected), or $754 of Utah-allocated tax affected PTC.

The other adjustments are related to the October outages at a Company-owned wind facility, resulting in an estimated 15,524,870 kWh of lost PTC-eligible production. The PTC value of the lost power is $388,122 on a Total Company basis ($514,659 tax affected), or $229,420 of Utah-allocated tax affected PTC.

Outages

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

We performed a detailed review of the thermal, wind, and hydro outage data as provided in the EBA filing and with the supporting documentation provided by RMP. Further documentation was sought for a select number of outages that were chosen based on the narrative description provided. While the information provided in the EBA filing for the thermal and hydro outages was sufficient, the wind outage documents provided little information on the root cause of the outages. After reviewing the filing requirements and data request responses provided, we found no reason to adjust the EBA costs because of the hydro outages. However, further review of the following specific thermal and wind outages was performed.

Our review of forced, maintenance, and extended planned outages at PacifiCorp's thermal plants during the EBA deferral period yielded 16 outages that warranted further investigation to determine whether there were any unnecessary increases to Company-wide NPC. Of these outages that warranted additional scrutiny, seven outages demonstrated sufficient imprudence that we recommend reducing EBA costs to reflect replacement power costs related to the outages.

The Company generally responds to questions related to plant specific actions taken by the Company to minimize outage durations and associated replacement power costs with general references to its ENDUR optimization process and its Commercial Objective Reports (COR) as evidence. While acceptable to a point, these responses fail to describe the more outage specific, plant driven approaches available to the Company that could include for example, expanded use of overtime, expedited deliveries of material and equipment as well as additional contractor labor. The Company has not shown that it is taking every prudent action at its disposal to minimize replacement power costs.

In addition to recommendations regarding outage imprudence and replacement power cost disallowance, we also find that the Company's lack of emphasis on providing plant specific evidence of what the plants are doing to minimize outage durations to be of concern. Further, it is incumbent on the Company to make every effort to make sure that "learnings" from outage events are properly vetted and corrective actions taken across the fleet documented to help proactively minimize future outages.

Outage	Start Month	Est. Lost MWh	Recommended EBAC Adjustment*
Outage A	September	3,764	$176,564
Outage B	July	15,895	$888,689
Outage C	November	17,254	$644,524
Outage D	April	4,149	$78,936
Outage E	May	9,614	$155,413
Outage F	November	6,076	$165,134
Outage G	October	2,573	$136,397
Outage H	October	2,604	$138,034
Outage I	October	5,143	$272,610
Outage J	October	5,205	$275,882
Total		73,345	$2,932,182

** Company-Wide NPC*

Figure ES-2. Summary of outage-related EBA adjustment recommendations

The table above summarizes our recommendations with respect to EBA adjustments totaling $2.9 million on a Company-wide NPC basis. The Division's separate report and testimony calculates the impact of our recommended adjustments on RMP's requested EBA recovery amount. On a Utah-allocated basis these adjustments result in a reduction of $1,313,706, including $24,697 of accrued interest to RMP's requested recovery of deferred EBAC.

On a Utah-allocated basis the outage and PTC adjustments result in a reduction of $1,543,125, this includes $28,504 of accrued interest to RMP's requested recovery of deferred EBAC.

Natural Gas & Power Transactions

Between 2013 and 2021, PacifiCorp engaged in tens of thousands of transactions on a system-wide basis for natural gas and electricity that settled in the 2021 EBA deferral period. The costs or proceeds of these transactions flow into net power costs. 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 44 broadly representative transactions (including 33 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 transactions were done, how the terms of each deal fit in the Company's market view at the time, and whether each deal conformed to risk management and corporate governance policies.

Based on our review of the sample transactions and the supporting information provided to us, we find no reason at this time to adjust the energy balancing account or net power costs for sample transactions reviewed.