CONFIDENTIAL

ENERGY BALANCING ACCOUNT AUDIT FOR ROCKY MOUNTAIN POWER FOR CALENDAR YEAR 2020 (DOCKET NO. 21-035-01)

PUBLIC EXECUTIVE SUMMARY

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PREPARED FOR

Division of Public Utilities

State of Utah

PREPARED BY

Daymark Energy Advisors

DAYMARK ENERGY ADVISORS

370 MAIN STREET, SUITE 325 | WORCESTER, MA 01608

TEL: (617) 778-5515 | DAYMARKEA.COM

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 ("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 June 14, 2021, RMP filed a corrected filing requesting to recover $3.36 million in deferred EBA costs incurred during the 12-month Deferral Period from January 1, 2020 through December 31, 2020.[1] RMP's request represents seven components, including two credits and five costs. The request is summarized in Table 1 of the direct testimony of Jack Painter, which is reproduced in Figure ES-1 below. The credits include $5.4 million for savings related to EBA costs. The cost components in the application include $5.0 million for a special contract customer, $3.1 million adjustment for Utah situs resources, $0.34 million in interest accrued through December 31, 2020, $0.06 million in interest accrued from January 1, 2021 through March 31, 2021, and $0.18 million in interest accrued from April 1, 2021 through February 28, 2022. All components represent Utah-allocated amounts, and there is no sharing band.

[1] Docket No. 21-035-01, Rocky Mountain Power, Application to Increase the Deferred EBA Rate Through the Energy Balancing Authority Account Mechanism corrective filing, June 14, 2021.

Calendar Year 2020 EBA Deferral			*Exhibit RMP___(JP-1) Reference*
Actual EBA ($/MWh)	$	25.07	*Line 5*
Base EBA ($/MWh)		25.25	*Line 10*
$/MWh Differential	**$**	**(0.18)**	
Utah Sales (MWh)		24,869,997	*Line 4*
EBA Deferrable*	$	(5,409,466)	*Line 12*
Special Contract Customer Adjustment*		5,010,211	*Line 15*
Utah Situs Resource Adjustment*		3,174,121	*Line 16*
Total Deferrable		2,774,865	*Line 17*
Interest Accrued through December 31, 2020		340,074	*Line 21*
Interest Accrued January 1, 2021 through March 31, 2021		61,919	*Line 23*
Interest Accrued April 1, 2021 through February 28, 2022		181,322	*Line 24*
Requested EBA Recovery	**$**	**3,358,179**	*Line 25*

* Calculated monthly

Figure ES-1. Summary of Calendar Year 2020 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. 21-035-01. The Company is requesting approval to recover $3.36 million in deferred EBA costs covering the differences between EBA costs incurred in the calendar year 2020 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 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 presented in Docket No. 19-035-01, and calendar year 2019 in Docket No. 20-035-01.

[2] Docket No. 21-035-01, Direct Testimony of Jack Painter, Table 1 at line 55.

[3] Docket No. 21-035-01, Rocky Mountain Power, Application to Increase the Deferred EBA Rate Through the Energy Balancing Authority Account Mechanism, March 15, 2021.

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 its report summarizing the results of their 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 NPC

The NPC category with the largest variance between Base and Actual values is wholesale sales revenue ($218 million decrease in revenue, increasing NPC). Purchased power expense in Actual NPC exceeded Base NPC by $26 million, resulting in a $244 million variance for wholesale sales and power purchases combined. 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 (particularly given the wide temporal mismatch between the 2014-15 test period and the 2020 deferral period), but rather focus on the drivers of difference that are within PacifiCorp's control.

The general decrease in wholesale sales for resale coupled with lower average sales prices resulted in increased Actual NPC. Higher purchases also drove an increase in Actual NPC over Base NPC, without any mitigation from lower average purchase prices. The variance from Base NPC is generally consistent with and explainable by market condition changes (notably the change in relative economics between coal-fired and natural gas-fired generation) between the Base NPC forecast for the 2014-15 test period and actual conditions during the 2020 deferral period, as well as changes in long-term contracts in effect for the respective periods.

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 and wind outages. However, further review of the following specific thermal outages was performed.

Our review of forced, maintenance, and extended planned outages at PacifiCorp's thermal plants during the EBA deferral period yielded 10 outages that warranted further investigation to determine whether there were any unnecessary increases to Company-wide NPC. Of these 10 outages that warranted additional scrutiny, two outages demonstrated sufficient imprudence that we recommend reducing EBA costs to reflect replacement power costs related to the outages.

The Company continues to respond 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. Absent evidence to the contrary, it is difficult to verify that the Company 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 across the fleet to help proactively minimize future outages.

Outage	Start Date	Outage Duration (Hours)	Est. Lost MWh	Recommended EBAC Adjustment*
Outage A	6/28/2020	73	34,524	$72,313
Outage B	7/5/2020	285	19,678	$41,078
TOTAL		**358**	**54,202**	**$113,391**
**Company-Wide NPC*				

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

The table above summarizes our recommendations with respect to EBA adjustments on a Company-wide NPC basis. The Division's separate report and testimony calculate 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 $53,873 to RMP's requested recovery of deferred EBAC.

Natural Gas and Power Transactions

Between 2013 and 2020, PacifiCorp engaged in tens of thousands of transactions on a system-wide basis for natural gas and electricity that settled in the 2020 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 46 broadly representative transactions (including 27 transactions related to PacifiCorp's hedging program) and accounting entry groupings and conducted extensive discovery on these transactions. Sample transactions were targeted for selection based on characteristics identified in the trade capture data provided in response to Filing Requirement 6(b), either to facilitate investigation of specific issues or questions or to ensure a broadly representative sample. We built on knowledge gained from similar review in previous EBA cases.

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.

Energy Imbalance Market Participation

We were asked to review the impact of PacifiCorp's fifth full calendar year of participation in the California Independent System Operator's ("CAISO") Energy Imbalance Market ("EIM"). PacifiCorp's participation in EIM impacts actual NPC in several ways, both directly and indirectly. As an example, there are direct costs and revenues associated with EIM transactions administered through the CAISO settlement system. As a result of trading energy imbalance through the EIM, the Company's own generation dispatch changes relative to what would have occurred absent the market, impacting fuel and purchased power cost indirectly. These impacts are not precisely quantifiable because they involve comparison to a counterfactual. Estimation of these impacts is necessary to determine if participation in EIM on balance reduces NPC.

RMP has testified that participation in the EIM provides benefits to customers in the form of reduced Actual NPC through lower fuel and purchased power cost.[4] The two main sources relied upon for this conclusion are PacifiCorp's own analysis showing $46.8 million in inter-regional benefits in the deferral period,[5] and CAISO's published EIM Benefits Report estimating a wider subset of benefits attributable to PacifiCorp of $59.8 million.[6] We reviewed the two studies to verify that customers benefit from the Company's participation in the EIM.

Based on our high-level review of these documents we have found no reason to challenge CAISO's methodology or its findings that EIM participants benefit significantly from real-time imbalance trading facilitated by the market. PacifiCorp's estimates of benefits tend to be more conservative than CAISO's but have been increasing relative to CAISO with being higher than that of CAISO in 2020. As the number of participating BAAs increases, it will be an increasingly complex challenge for PacifiCorp to quantify benefits independently of CAISO. However, we find no reason to disagree with the joint

[4] Docket No 21-035-01, Direct Testimony of Jack Painter, Page 13, Line 271 - 275.
[5] Docket No 21-035-01, Direct Testimony of Jack Painter, Page 13, Line 275.
[6] California ISO, *Western EIM Benefits Quarterly Benefits*. Available at: https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx , accessed on August 8, 2021.

conclusion of CAISO and PacifiCorp that participation in EIM delivers material benefits to PacifiCorp customers.