# ENERGY BALANCING ACCOUNT AUDIT FOR ROCKY MOUNTAIN POWER FOR CALENDAR YEAR 2019 (DOCKET NO. 20-035-01)

## PUBLIC EXECUTIVE SUMMARY

**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 ("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 16, 2020, RMP filed a request to recover $36.8 million in deferred EBA costs incurred during the 12-month Deferral Period from January 1, 2019 through December 31, 2019.[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 David G. Webb, which is reproduced in Figure ES-1 below. The credits include $2.9 million for savings related to the Retiree Medical Obligation and $8.7 million for sales to a special contract customer. The cost components in the application include $44.0 million in EBA costs, $1.6 million adjustment for Utah situs resources, $1.2 million in interest accrued through December 31, 2019, $0.4 million in interest accrued from January 1, 2020 through March 31, 2020, and $1.3 million in interest accrued from April 1, 2020 through February 28, 2021. All components represent Utah-allocated amounts, and there is no sharing band.

[1] Docket No. 20-035-01, Rocky Mountain Power, Application to Increase the Deferred EBA Rate Through the Energy Balancing Authority Account Mechanism, March 16, 2020.

| Calendar Year 2019 EBA Deferral | | Exhibit RMP (DGW-1) Reference |
|---|---|---|
| Actual EBA ($/MWh) | $ 27.05 | Line 5 |
| Base EBA ($/MWh) | 25.25 | Line 10 |
| $/MWh Differential | **$ 1.80** | |
| Utah Sales (MWh) | 24,669,334 | Line 4 |
| EBA Deferrable* | $ 43,978,176 | Line 12 |
| Incremental Non-Fuel FAS 106 Savings* | (2,947,878) | Line 13 |
| Special Contract Customer Adjustment* | (8,733,909) | Line 16 |
| Utah Situs Resource Adjustment* | 1,641,004 | Line 17 |
| Total Deferrable | 33,937,393 | Line 18 |
| Interest Accrued through December 31, 2019 | 1,212,736 | Line 22 |
| Interest Jan 1, 2020 through Mar 31, 2020 | 385,415 | Line 24 |
| Interest Apr 1, 2020 through Feb 28, 2021 | 1,284,513 | Line 25 |
| **Requested EBA Recovery** | **$ 36,820,057** | Line 26 |

* Calculated monthly

**Figure ES-1. Summary of Calendar Year 2019 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. 20-035-01. The Company is requesting approval to recover $36.8 million in deferred EBA costs covering the differences between EBA costs incurred in calendar year 2019 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 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

[2] Docket No. 20-035-01, Direct Testimony of David G. Webb, Table 1 at line 60.

[3] Docket No. 20-035-01, Rocky Mountain Power, Application to Increase the Deferred EBA Rate Through the Energy Balancing Authority Account Mechanism, March 16, 2020.

presented in Docket No. 18-035-01, and calendar year 2018 presented in Docket No. 19-035-01.

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 its own 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 ($214 million decrease in revenue, increasing NPC). Purchased power expense in Actual NPC exceeded Base NPC by $82 million, resulting in a $296 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 2019 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 2019 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 12 outages that warranted further investigation to determine whether there were any unnecessary increases to Company-wide NPC. Of these 12 outages that warranted additional scrutiny, four outages demonstrated sufficient imprudence that we recommend reducing EBA costs to reflect replacement power costs related to the outages.

A troubling trend developed during this investigation relative to the Company's responses to questions related to what specific actions had been taken by the Company to minimize outage durations and associated replacement power costs. On multiple occasions, the Company simply referred its application of ENDUR optimization process and its Commercial Objective Reports (COR) on an ongoing basis 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 expanded use of overtime, expedited deliveries of material and equipment as well as additional contractor labor. Absent evidence to the contrary it is impossible to verify that the Company is taking every prudent action available to the Company to minimize customer replacement power costs.

In the case of outages caused by avoidable mistakes or oversight by PacifiCorp or its third-party contractors, we recommend the adjustment of EBA costs based on the incremental market power costs during the outage period relative to generation costs if the unit had been operating normally. Estimation of replacement power costs is necessarily imprecise because it is impossible to know with certainty the PacifiCorp dispatch, bilateral transactions, and market outcomes in the counterfactual scenario with the subject unit online. Our methodology relies on available market data or proxy data, actual Company costs, and reasonable assumptions to construct counterfactual scenarios.

| Outage | Start Month | Est. Lost MWh | Recommended EBAC Adjustment* |
|---|---|---|---|
| Outage A | February | 7,945 | $382,578 |
| Outage B | July | 51,339 | $961,876 |
| Outage C | August | 482,885 | $4,581,742 |
| Outage D | June | 27,460 | $101,236 |
| **Total** | | 569,629 | $6,027,431 |

** 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 $2,792,525 to RMP's requested recovery of deferred EBAC.

## Natural Gas and Power Transactions

Daymark also evaluated a sample of trading transactions for accuracy, completeness, and prudence. Between 2013 and 2019, PacifiCorp engaged in many thousands of transactions on a system-wide basis for natural gas and electricity that settled in the 2019 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 48 broadly representative transactions (including 24 transactions related to the Company's hedging program) and accounting entry groupings and conducted extensive discovery on these transactions. The sample included 10 gas financial, 10 gas physical, and 28 power physical 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 fourth 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 offered testimony 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 $57.2 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 public reports produced by CAISO supporting its benefits estimates 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 over the past three years. 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

[4] Direct Testimony of David G. Webb, Page 15, Line 292 – 294.
[5] Direct Testimony of David G. Webb, Page 16, Line 296.

[6] California ISO, *Western EIM Benefits Quarterly Benefits*. Available at: https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx , accessed on October 14,2020.

no reason to disagree with the joint conclusion of CAISO and PacifiCorp that participation in EIM delivers some benefits to PacifiCorp customers.

### Trade Purpose Documentation

PacifiCorp's risk management policies create "guardrails" that prevent the Company from extreme under- or over-hedged positions. However, between those rails, there is wide latitude within which traders routinely use discretion to make or not make trades that impact the Company's exposure to changes in market conditions on NPC. It is appropriate for the Company's hedge policies to not be overly prescriptive, and to rely on some element of judgment to fine-tune the Company's position within prudent limits.

One of the questions we apply to hedging transactions in our review is to ask what reason the Company had to make *that* particular trade at *that* particular time. Each trade should have contemporaneous documentation of an articulable trade purpose that goes beyond general compliance with policy requirements and broad statements of strategy that don't change over time. Such documentation is a critical element for the Company to demonstrate prudence of costs incurred resulting from its trading program.

In accordance with the Settlement Stipulation resolving the EBA for the 2013 deferral period (Docket No. 14-035-31), we have routinely accepted Commercial Objective Reports (CORs) as contemporaneous documentation of trade purpose.

During the three-year period ending in 2019 during which the hedging transactions were executed that are subject of this review, the Company's CORs do not contemporaneously capture trade purpose for the reasons we outline in this report. The CORs were rarely updated and prone to obvious oversights that could remain undetected for months and years. The CORs also offered specific trading indications that appear to have been ignored without explanation for much of 2019.

The Company bears the burden of proof to demonstrate that it acted reasonably and prudently. To meet this burden the Company must not only demonstrate that it is compliant with its risk management policy, but is also must demonstrate that, with the information available at the time, it acted reasonably in a manner to benefit customers. This demonstration cannot be made without contemporaneous documentation of trade purpose.

The Company should require all traders to record basic trade purpose documentation for all hedging transactions. It is not unduly burdensome for traders and management to memorialize this information as part of the trading and trade capture process because the number of these transactions is relatively limited, and the time and resources needed to record this information are minimal. We will make recommendations for disallowances in future EBA audits if this critical component for demonstrating prudence of individual hedging transactions cannot be provided.