Docket No. 24-035-01

DPU EXHIBIT 1.1 Dir – PUBLIC
EXECUTIVE SUMMARY

January 1, 2023 – December 31, 2023

2024 EBA AUDIT REPORT FOR ROCKY MOUNTAIN POWER

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EXECUTIVE SUMMARY – NON-CONFIDENTIAL

The Utah Division of Public Utilities (Division or DPU) and its outside consultant, Daymark Energy Advisors, Inc. (Daymark), have completed the 2024 audit of Rocky Mountain Power's (RMP, Company) Energy Balancing Account (EBA) for the calendar year 2023 (2023 Deferral, Deferral Period).

The Division recommends a recovery amount of $276.7 million for the 2023 Deferral Period. This recommended recovery includes Daymark's $20.2 million recommended adjustments described below.

Summary observations with recommended adjustments:

1. Other than the inclusion of $24.2 million of added interest for July 1, 2024, through June 30, 2026, and the Company's changes to the EBA, the Company's application and level of documentation were generally comparable to that provided in prior filings.

2. The Company was generally complete and timely in its Data Request responses.

3. The Company reported a large Total PacifiCorp-wide 2023 EBA deferral of $1.1 billion in unallocated and unadjusted NPC above the base set in the 2020 GRC.

   The $1.1 billion Total Company, unadjusted EBA deferrable (Actual NPC – Base NPC) was due to:
   $49.1 million decrease from sales for resale,
   $842.1 million increase from purchased power,
   $18.5 million increase from wheeling expense,
   $45.3 million decrease from coal fuel expense,
   $257.3 million increase from natural gas expense,
   $2.8 million increase in other (wind) expenses.

4. The Utah allocated portion of the 2023 EBA deferral totaled $490.1 million in unadjusted NPC above the base set in the 2020 GRC. This amount includes the interest rate correction identified by the Division prior to the interim rate hearing, and it excludes the interest that was forecast to accrue during the proposed collection period from July 2024 through June 2026.

5. After the Company's inclusion of the Utah allocated wheeling revenues, PTCs and collection variance adjustments, the combined impact on the Total Deferrable EBA equaled $450.9 million according to RMP.

   The $490.1 million Utah allocated NPC deferrable (Actual NPC – Base NPC) was reduced to $450.9 million due to:

$24.3 million in Wheeling Revenues Variance (Actual – Base),
$1.4 million in PTC Variance (even with the increased tax credit rate),
$16.3 million in Base NPC Collection Variance.

6. The $450.9 million Utah Allocated EBA deferrable was further adjusted to the Company's Requested EBA Recovery, as filed, to $431.6 million due to the following adjustments:[1]

   $41.4 million decrease from a special contract customer adjustment,
   $1.7 million increase from Utah Situs Resource adjustment,
   $1.1 million increase from 2002 EBA Collection True Up,
   $0.2 million decrease from 2023 EBA Final Order Adjustment,
   $9.0 million increase from accrued interest through December 31, 2023,
   $4.8 million increase from accrued interest January 1, 2024 through March 31, 2024,
   $5.7 million increase from accrued interest April 1, 2024 through June 30, 2024. (this amount includes the $826,579 interest correction)

   The $431.6 million is significantly higher than the Company's largest previously requested net deferral recovery of $175 million for EBA deferral year 2022.

   The Company's $431.6 million recovery request was then increased to $455 million with the inclusion of $24.2 million in interest that was anticipated to accrue during the proposed collective period of July 1, 2024, through June 30, 2026. The inclusion of anticipated collection period is a divergence from prior year's filings. In prior EBA filings, interest during the collection period has been included in the deferral year filing for the year the interest had accrued. This $24.2 million in interest was removed from the ordered interim rate amount as mentioned below.

7. As a result of the 2021 General Session of the 64th Legislature, Utah Code section 54-7-13.5 was revised to expressly authorize the Commission to allow interim rate treatment of Energy Balancing Account Costs (EBAC) subject to the Commission's authority to later order a refund or surcharge. The Code was also amended to limit the annual review and final Commission order to 300 days after the Company's annual application filing date. The Company filed its annual EBA report on May 1, 2024.

   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

[1] CONFIDENTIAL RMP Attachment 6 – Painter Workpapers of Exhibit JP-1 5-1-2024, tab TABLE 1.

allowed EBAC, effective July 1, 2024.[2] The approved interim rate resulted in an approximate 12.7% increase to Utah customers.

8. The Company included PTCs in its confidential workpapers presented with Mr. Painter's direct testimony, as allowed by Commission order in the 2020 GRC, Docket No. 20-035-04. Actual generation from PTC-eligible generation wind facilities was less than expected in 2023, resulting in a realized $1.4 million increase in the Company's requested deferral.

   The Company's requested 2023 deferral recovery calculates an 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 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, PTCs under-performance increased the Company's 2023 deferral recovery by an estimated $22 million.[3] Continued under-performance of the inherently variable wind facilities could demonstrate an overreliance on forecast PTCs expected to offset capital costs.

9. The Division provided Daymark with a scope of work to perform. The Division asked Daymark to review variants of actual NPC versus Base NPC, outages, PTCs, natural gas and power transactions, a high-level review of Energy Imbalance Market (EIM) benefits, and changes to energy risk management policies. The results of this review are provided in Daymark's separately issued Testimony, Executive Summary, and 2024 EBA Audit Report.[4]

10. The Company reported that coal supply issues that began in 2022 continued through 2023. The Company adjusted its overall system operations due to the lack of coal supply in Utah by increasing market purchases and natural gas output. The decrease in plant generation resulted in a decrease in wholesale sales. Purchased power expenses were the highest ever recorded causing the largest deferral to date.

11. As presented in Jack Painter's testimony, the Company changed the EBA deferral calculation by adding expenses associated with export credits from Electric Service Schedule No. 137 - Net Billing Service for customer-owned generators. The Schedule

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[2] June 28, 2024, Commission Order approving interim rates.

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

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

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 $8,998,928. Of this amount, $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 as shown in DPU Table 1.

DPU TABLE 1

	Schedule 137 Actual Costs	**Estimated Interest**	**TOTAL**
2023 Deferral Year	$4,295,135	$183,845	$4,478,980
Prior Period 2020 - 2022	$4,703,793	$126,926	$4,830,719
TOTAL	$8,998,928	$310,771	$9,309,698

The Schedule 137 costs incurred prior to 2023 were not booked to any FERC account and were mistakenly thought to have been booked to existing Utah solar export credits. The Company is seeking to use the EBA mechanism to correct these errors by requesting current ratepayers pay costs that started accumulating approximately four years ago by a different set of customers.

Prior Period Adjustments have been accepted and defined in the Company's annual filing in Additional Filing Requirement (AFR) 15 as:

> Prior Period Adjustments - prior period adjustments represent accounting transactions booked during calendar year 2023, but that are related to operating periods prior to the inception of the EBA on October 1, 2011. Prior period adjustment accounting entries are zero in this EBA deferral period.[5]

It has been accepted and agreed that NPC costs prior to October 1, 2011 are excluded from recovery through the EBA. Generally, accounting transactions booked during the deferral period that are related to deferral periods that have been finalized by

[5] RMP EBA Additional Filing Requirement 15

Commission order should also be adjusted out of current deferral period reconciliation and review, unless there was cause for the Company to delay the booking. Such reasons might include an unknown amount, a later adjustment in amounts owed for taxes, or a similarly unknown or unknowable prudent component of costs.

The issue of introducing costs incurred prior to the current deferral year from prior years already finalized by Commission order was addressed in EBA Docket No. 16-035-01. In the 2016 review of the 2015 deferral year, the Division recommended removal of NPC items that are attributed to the periods prior to the 2015 deferral year. In defense, the Company provided rebuttal explaining that they had booked these prior period items in the deferral year 2015 due to differing accounting and operating periods.

> Each accounting entry in NPC has an accounting period and an operating period. The accounting period is the month and year in which the entry is booked, and the operating period is the month and year in which the transaction occurred. Typically, the accounting period and the operating period are the same; however, there are times when they are not. For example, during the checkout process for reconciling transactions with counterparties, if the Company does not come to an agreement with the counterparty on a certain transaction before closing the accounting period an estimate will be booked to properly account for the purchase or sale that has taken place. Once the checkout process has been completed for that transaction an adjusting accounting entry is made in a later accounting period but with an operating period that corresponds to the underlying transaction.[6]

The details of the Company's request to recover $4.7 million, with interest, in Schedule 137 costs for the prior period 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 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.

Cost recovery is expected to occur at a time that is close in time to cost origination. This "close in time" standard is the purpose for the Utah Code section 54-7-13.5 requirement to "file a reconciliation of the energy balancing account with the commission at least

[6] In the Matter of Rocky Mountain Power's Application to Decrease the Deferred EBA Rate through the Energy Balancing Account Mechanism, Docket No. 16-035-01, Response Testimony of Michael G. Wilding at 5:91-6:102 (Sep. 28, 2016).

annually." The annual reconciliation is the time for the Company to detail all its costs for the deferral year. Once final rates are approved for the most recent deferral year reconciliation, only costs associated with the current interim rate true up and final Commission ordered adjustment should be introduced as a prior period adjustment in a future EBA filing for recovery. Generally, allowing any additional expenses from prior periods that have already been finalized through Commission order into a current deferral year review unfairly subjects ratepayers to selective retroactive cost recovery not envisioned by the annual EBA recovery mechanism and excuses the Company's neglect at ratepayer expense. This unfairness becomes more obvious and egregious when multiple EBA account reconciliations have occurred between the period of cost accumulation and the date of the request for recovery. Preference for bringing finality to cost recovery and rate setting is encouraged to maintain confidence in established processes with the annual reconciliation of an established EBA account. As noted, exceptions to this general practice may be warranted, depending on the specific details, for costs that were unknown or unknowable at the time of the filing for the subject year's recovery.

The Division recommends the acceptance of the Schedule 137 costs for the deferral year 2023 as presented by the Company. However, the Division has the ongoing responsibility to identify matters that may not be just and reasonable; therefore, 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.

12. In July 2021, the Company unilaterally changed its hedging program without any input or approval from the Commission. This was a significant deviation from the prior program, which evolved from cooperative discussions between the Company and other interested parties after the 2010 general rate case. The new program has drastically increased the Company's hedging market purchases and costs contributing to the large EBA deferrals starting in 2021 are shown in DPU TABLE 2 (all values are Utah allocated). The vast majority of the purchases occur on the West side of the system and are unlikely to meaningfully serve Utah load. The Company has not shown 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.

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		

The Company's decisions not to model proven resource types and focus planning on other priorities[7] 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 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.

Despite the Division's attempts to evaluate the new program over recent years, it is still unclear what the exact incremental costs of the new program are, the resulting impacts on Company owned plant dispatch, and what market options and alternatives exist to meet the program's purported goals for the western states of Washington, Oregon, and California (PAC West) and eastern states of Idaho, Wyoming, and Utah (PAC East). This new hedging program currently does not appear to have an organized process to evaluate its effectiveness or evaluate its costs so that these costs can be properly allocated.[8]

Of the Utah allocated power physical trades that settled in 2023; the PAC West side of the system accounted for approximately 90% of these market trades.

[7] 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.

[8] PAC West purchases appear to be primarily for procuring operational supply.

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. It is unclear what impact individual state policies and preferences have had on the structure of the current power physical purchases occurring for PAC West and past planning decisions that excluded proven resource types. The current allocation of expenses incurred under the Company's unilaterally chosen program is not in the public interest.

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.

13. 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:

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

    $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.

    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**