UTAH DEPARTMENT OF COMMERCE
Division of Public Utilities

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Preliminary Review – Interim Rate Recommendation

To: Public Service Commission of Utah

From: Utah Division of Public Utilities

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Date: May 24, 2024

Re: **Docket No. 24-035-01,** In the Matter of Rocky Mountain Power's Application for Approval of the 2024 Energy Balancing Account Increase – Interim Rate Request.

Recommendation (Approval With Conditions)

The Division of Public Utilities (Division or DPU) has reviewed Rocky Mountain Power's (Company or RMP) May 1, 2024, Energy Balancing Account (EBA) filing and notes the following changes included in the Company's EBA Application (Application), inconsistent with prior years' filings:

1) A 24-month collection period from July 1, 2024, through June 30, 2026, with accrued interest, proposed and assumed in the Company's filing and calculations.

2) $24,201,822 included interest expected to accrue through the rate effective collection period from July 1, 2024, through June 30, 2026 (Collection Period Interest).

Under Utah Code section 54-7-13.5, the Company must make an adequate prima facie showing that the proposed interim rate filing appears consistent with prior years' filings.[1] As the proposed 24-month collection period and the inclusion of Collection Period Interest in interim rates are proposed changes to the EBA, inconsistent with prior years' filings, the Division recommends disallowing these changes primarily to avoid conflicts with the statute. A one-year collection also minimizes carrying charges and avoids challenges created by a two-year amortization.

During its initial review, the Division discovered an incorrect interest rate used in the Company's calculation of accrued interest for the period from April 1, 2024, through June 30, 2024, and recommends increasing the 2023 deferral by $826,579 to correct this error.

After the removal of the $24,201,822 of Collection Period Interest and adding the $826,579 rate correction, the Division calculated an adjusted interim rate deferral of $431,578,182. The Division will have additional details and other adjustments to present in its final report in this docket.

The Division recommends an interim rate collection based on the Division's calculated adjusted deferral amount of $431,578,182 and consistent with prior years' filings, a collection period of 12 months, from July 1, 2024, through June 30, 2025.

Background

On May 1, 2024, the Company filed its annual report for the Energy Balancing Account. In its Application, the Company requested an interim rate increase effective July 1, 2024, based on its calculated 2023 deferral year recovery of $455 million.[2] The requested $455 million is the largest requested EBA recovery and is 160% ($280 million) more than EBA deferral year 2022 and over 400% ($364 million) more than EBA deferral year 2021. The 2021 deferral year was the first year the EBA filing used the 2020 EBA Base (EBA Base or Base) set in the 2020 General Rate Case (2020 GRC).

[1] Utah Code Ann. § 54-7-13.5 (2)(k)(iii)(A)
[2] Direct Testimony of Jack Painter, Page 2, Lines 39 – 45.

DPU TABLE 1

EBA Recent History [3]

Docket No	Deferral Period (Calendar Yr)	Total Deferral ($m)	Collection (Yrs)	Effective Date	Ending Date
24-035-01	2023	$455.0	2.00	7/1/2023	6/30/2026
23-035-01	2022	$175.8	1.00	7/1/2023	6/30/2024
22-035-01	2021	$90.1	1.17	5/1/2022	6/30/2023
EBA BASE Reset in Docket 20-035-04					
21-035-01	2020	$1.7	1.00	3/1/2022	2/28/2023
20-035-01	2019	$36.8	1.00	3/1/2021	2/28/2022
19-035-01	2018	$17.3	1.00	4/1/2020	2/28/2021

In Jack Painter's pre-filed Direct Testimony, he explained that the large record deferral comprised, on a Utah allocated basis, $450.9 million of EBA-related costs, $38.8 million in credits and adjustments and $42.9 million of interest. The $450.9 million in EBA related costs is calculated as the difference between the actual Net Power Costs (NPC), Production Tax Credits (PTC), and wheeling revenue allocated to Utah based on the 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol (2020 Protocol), and the 2020 Base NPC (Base NPC), PTCs, and wheeling revenue, established in the 2020 GRC. Collectively, NPC, PTCs, and wheeling revenue components are defined in the Company's EBA tariff, Schedule 94, as Energy Balancing Account Costs (EBAC). [4]

Mr. Painter's summarized reasons for the increased NPC included the following:

1) coal fuel supply constraints caused drastically decreased generation and lower coal fuel expense compared to the 2020 Base. The lack of coal fuel supply and generation resulted in the reliance on more expensive replacement power and lower wholesale sales;[5]

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[3] All information as filed by Rocky Mountain Power in the referenced docket number.
[4] Direct Testimony of Jack Painter, Page 4, Lines 62 – 63.
[5] Direct Testimony of Jack Painter, Page 18, Lines 333 – 339.

2) increased reliance on market power purchases at higher average market prices resulted in a significant increase in market purchases, the largest component of the total deferral; [6]

3) increased natural gas fuel expense due to higher average prices than assumed in Base;[7] and

4) the lowest wholesale sales volumes since the Base was set in 2020.

DPU TABLE 2 below is a comparative three-year view of NPC components Mr. Painter identified as the drivers of the annual deferrals. The values are Utah allocated actual annual NPC expense and revenue deviations from the NPC base.[8] The combined natural gas and purchased power expenses increased the 2023 Utah allocated deferral by more than $474 million. The NPC base is included for reference.

DPU TABLE 2

	DEFERRAL YEAR[9]			NPC BASE
	2023	**2022**	**2021**	2020
Increase/(Decrease) over NPC BASE:				
Wholesale Sales Revenue ($)	**(21,678,175)**	30,809,881	(17,278,355)	98,192,924
Purchased Power Expense ($)	**356,737,641**	158,483,415	58,255,335	265,535,634
Coal Fuel Expense ($)	**(14,821,450)**	(2,973,592)	22,240,837	261,276,915
Natural Gas Expense ($)	**117,677,630**	142,025,162	27,950,795	131,643,994

DPU TABLE 3 below provides a three-year comparison of the Company's system total actual generation deviations from the NPC Base.[10] The values reflect the Company's underperforming assets and the increasing dependence on market transactions to meet load requirements. The NPC base is included for reference.

[6] Direct Testimony of Jack Painter, Page 19, Lines 352 – 357.
[7] Direct Testimony of Jack Painter, Page 20, Lines 372 – 375.
[8] Direct Testimony of Jack Painter, CONFIDENTIAL RMP Attachment 6 – Painter Workpapers of Exhibit JP-1 5-1-2024
[9] Confidential DPU Exhibit 6 – NPC Comparisons.
[10] Direct Testimony of Jack Painter, CONFIDENTIAL RMP Attachment 6 – Painter Workpapers of Exhibit JP-1 5-1-2024

DPU TABLE 3

	DEFERRAL YEAR[11]			NPC BASE
	2023	**2022**	**2021**	2020
Increase/(Decrease) over Total Company Base (MWh):	**(3,116,169)**	(850,577)	(1,598,495)	67,622,014
Wholesale Sales Generation (MWh)	**(4,460,294)**	(2,450,754)	(2,203,088)	7,042,269
Purchased Power (MWh)	**4,945,539**	449,534	(2,375,619)	13,807,579
Coal Generation (MWh)	**(6,143,046)**	296,913	3,496,189	28,094,068
Natural Gas Generation (MWh)	**(378,156)**	(742,492)	(1,116,372)	14,428,068
Wind Generation (MWh)	**(914,243)**	(163,628)	(765,353)	7,665,637
Hydro Generation (MWh)	**(626,263)**	(690,904)	(837,340)	3,626,662

The Company's wind assets in aggregate have consistently underperformed each year with the calendar year 2023 being the lowest in the last three years as shown in DPU TABLE 3 above. As ordered in the 2020 GRC, the Company has included PTCs in the EBA calculations included in its 2022, 2023, and 2024 EBA filings. The Company's actual 2023 wind generation and resulting PTCs were lower than the 2020 GRC PTC Base (PTC Base) increasing the deferral amount by the unrealized PTCs. PTCs are calculated using the appropriate tax credit rate from the Internal Revenue Service (PTC Credit Rate) and using the System Generation allocation factor (SG Factor) established in the 2020 Protocol. The PTC Credit Rate and the SG factor can fluctuate and have changed since the PTC Base was approved. By removing the differences in the PTC Credit Rate and the SG Factor from the actual PTCs and the PTC Base calculations, the Division estimates that the unrealized PTCs increased the 2023 deferral by $14,016,792 as shown in DPU TABLE 4 below. Detailed calculations are included as Confidential DPU Exhibit 2 – Unrealized PTCs. The Division is not recommending an adjustment resulting from the unrealized PTCs.

[11] Confidential DPU Exhibit 6 – NPC Comparisons.

DPU TABLE 4

	Unrealized PTCs - DPU Estimated		
	Deferral Year		
	2023	**2022**	**2021**
TOTAL Unrealized PTCs ($) After removal of Credit Rate and SG Factor Differences	**14,016,792**	11,261,019	10,588,142

DPU TABLE 5 below provides a three-year deferral comparison of actual average annual prices and the average annual price presumed in Base.[12] Natural gas generation and purchased power prices were significantly higher than initially presumed in Base.

DPU TABLE 5

	DEFERRAL YEAR[13]			BASE
	2023	**2022**	**2021**	**2020**
Purchased Power ($/MWh)	76.94	67.46	65.80	43.50
Coal Generation ($/MWh)	25.39	20.46	19.88	21.45
Natural Gas Generation ($/MWh)	39.61	44.61	26.40	20.73

Coal supply constraints which began at the end of calendar year 2022, continued through 2023 (and still impact the Company today) [14] causing an increase in the Company's natural gas generation and further dependence on replacement market power purchases. Market power prices and natural gas prices have also risen sharply since the Base was set, further increasing the 2023 deferral. System balancing purchases that are included in the reported market power purchases increased significantly. Mr. Painter reported that short term firm purchases (system balancing purchases) "increased from $17.17/MWh in Base NPC to $116.40/MWh, or 578 percent and actual market purchase volumes increased by 4,250

[12] Direct Testimony of Jack Painter, CONFIDENTIAL RMP Attachment 6 – Painter Workpapers of Exhibit JP-1 5-1-2024.
[13] Confidential DPU Exhibit 6 – NPC Comparisons.
[14] Direct Testimony of Jack Painter, Page 16, Lines 308 – 309.

GWh or 120 percent higher than Base NPC."[15] The Division will review and report any findings related to these items in its final report. Market power purchases for the calendar year 2023 were significantly higher than Base, the highest to date.

Mr. Painter reported that the Company's filing contained changes to the EBA deferral calculations that have not been previously introduced or approved by the Commission including:

> the inclusion of the expense associated with export credits from Electric Service Schedule No. 137 - Net Billing Service for customer owned generators,[16] and
>
> the inclusion of the interest accrued through the rate effective period from July 1, 2024, through June 30, 2026.[17]

The Division will review the inclusion of the expense associated with export credits from Electric Service Schedule No. 137 during its full review.

Mr. Painter's Direct Testimony Table 1 and related workpapers included $24,201,822 for interest that would accrue in its proposed collective period of July 1, 2024, through June 30, 2026.[18] Including Collection Period Interest anticipated to accrue through the rate effective collection period in the initial EBA filing for inclusion in interim rates is a divergence from prior year's filings. In prior EBA filings interest that has accrued during the collection period, is included in the deferral year filing for the year the interest has accrued. The included $24,201,822 of future interest was included as a set number, provided without any calculation to understand the underlying assumptions and details, including the rate of interest assumed through the 24-month period.

The carrying charge for the EBA has been established as the rate set in Electric Service Schedule 300, which is updated annually. Accordingly, the carrying charge would change twice during the Company's proposed 24-month period. The Division believes that interest

[15] Direct Testimony of Jack Painter, Page 18, Lines 337 – 339.
[16] Direct Testimony of Jack Painter, Page 3, Lines 48 – 49.
[17] Direct Testimony of Jack Painter, Page 3, Lines 50 – 51 and Page 4, Line 62, Table 1.
[18] Ibid.

accruing during the collection period has not been included in past EBA initial filings for reasons that include the following:

1) The EBA was established to allow the Company to recover prudently incurred actual costs,[19] not anticipated or forecasted costs. It excludes expenses yet to be incurred.

2) Theoretically, the Base NPC, set in the most recent general rate case, and Actual EBA results of operations NPC should be relatively close, making the amount of anticipated interest accruing during the collection period small.

Precedentially, the only interest included in the Company's annual initial EBA filings has been the interest in the deferral year up to the Commission's ordered rate effective date fixing the EBA on an interim or final basis. The Company included a rollover of $1.1 million in unrecovered deferred balances that were previously approved for recovery in the 2022 EBA.[20] This rollover amount includes adjustments occurring and interest accruing during the 2022 EBA deferral year collection period (May 2022 through June 2023). The details of this added rollover were not provided in the May 2024 filing but were provided through expedited discovery and included with this report as DPU Exhibit 3 – 2022 EBA Rollover. The Division requests that information and calculations related to the EBA deferral calculation and collection, specifically any adjustments and EBA collections occurring during the deferral year, be included in future EBA annual filings.

Under Utah Code section 54-7-13.5, the Company must make an adequate prima facie showing that the proposed interim rate filing appears consistent with prior years' filings. As the Company has not included any future interest anticipated to accrue during the collection period in prior initial EBA applications,[21] or included this interest in interim rates, the Division recommends the removal of the proposed $24,201,822 in interest expected to accrue during the collective period from July 1, 2024, through June 30, 2026. This avoids conflicting with the statute.

[19] Utah Code Ann. § 54-7-13.5 (2)(k)(iii)(A)
[20] Direct Testimony of Jack Painter, Page 3, Lines 54 – 55.
[21] Direct Testimony of Jack Painter, Page 8, Lines 148 – 150.

During the Division's interim rate review of Mr. Painter's Exhibit 1 - Commission Order Calculation Method workpaper it discovered that an incorrect interest rate of 4.57% was used to calculate accrued interest for the period from April 1, 2024, through June 30, 2024. After updating the calculation with the correct rate of 5.34%[22] (the carrying charge established in the most recent Electric Service Schedule 300, effective April 1, 2024) the resulting 2023 deferral increased by $826,579 as shown in DPU TABLE 6 below.

DPU TABLE 6

Interest - April 1, 2024 - June 30, 2024

Outstanding Deferral	$ 425,867,513		$ 425,867,513
Interest Rate	**5.34%**		4.57%
Calculated Interest	**$ 5,710,669**		$ 4,884,089
Calculated Difference		**$ 826,579**	

After the removal of the $24,201,822 in future interest included by the Company and the addition of $826,579 to correct the interest rate in Mr. Painter's Exhibit 1, the Division recommends that the calculated total deferral of $431,578,182 be recovered over 12 months on an interim rate basis subject to any additional adjustments made in the Commission's final order establishing the 2024 EBA.

In its Application, the Company proposes to collect the 2023 deferral over 24 months. A two-year collection period is inconsistent with prior EBA applications that have established the deferral recovery collection period at 12 months to avoid and mitigate collection recovery overlap. Mr. Meredith cited mitigation of rate impacts as the Company's only justification for the proposed 24-month collection period.[23] To effectively mitigate rate impacts by lengthening the collection period to 24 months, as the Company proposes,

[22] Direct Testimony of Jack Painter, CONFIDENTIAL RMP Attachment 6 – Painter Workpapers of Exhibit JP-1 5-1-2024
[23] Direct Testimony of Robert Meredith, Page 2, Lines 24 – 25.

would require the next deferral recovery to be significantly lower than the current trend has established. If not, deferring $227.50 million into the collection year 2025-2026,[24] on top of another likely large deferral recovery for the 2024 deferral year, would compound the rate impacts to customers and incur additional unnecessary interest. While this year's increase would be smaller, next year's would likely be larger. Moving back to a one-year collection period could prove exceptionally difficult as markets continue showing rising prices and a reset of base rates appears to be some way off. With the Company's proposed 24-month collection period, the Division estimates that customers would be required to pay approximately $12 million in unnecessary interest. A collection period comparison is included below in DPU TABLE 7.

DPU TABLE 7

Collection Period Comparison

	Interest Rate	Principal	Interest	Monthly P&I
1 Year Collection Period (Division Proposed)	5.34%	431,578,182	12,585,012	37,013,599
2 Year Collection Period (same rate & principal)	5.34%	431,578,183	24,415,061	18,999,718
Calculated Difference			(11,830,049)	18,013,881
1 Year Collection Period (Division Proposed)	5.34%	431,578,182	12,585,012	37,013,599
2 Year Collection Period (Company Proposed)	?	454,953,425	24,201,822	?
Calculated Difference		(23,375,243)	(11,616,810)	

The Company has not provided evidence to support that the 2024 EBA deferral, filed in 2025, will be considerably lower. In fact, Mr. Painter stated that the underlying factors for the large 2023 deferral are ongoing, including the coal supply and coal generation

[24] Direct Testimony of Robert Meredith, Page 2, Lines 34 – 37.

challenges that still impact the Company today.[25] As previously stated, the Company must make an adequate prima facie showing that the proposed interim rate filing appears consistent with prior years' filings.[26] A 24-month collection period is not consistent with the 12-month collection period established in prior year filings. The Division recommends rejecting the proposed 24-month collection and approve a 12-month collection period, ending June 30, 2025, to avoid conflicts with Utah Code section 54-7-13.5.

As detailed in Mr. Meredith's workpapers, the proposed 24-month recovery of the 2023 deferral was spread across customer rate classes.[27] The rate spread, rate design, and billing determinants appear consistent with the method approved in the 2020 GRC. Mr. Meredith also included revisions to Electric Schedule 94 consistent with the Company's proposal and the changes originating from the 2023 EBA, Docket No. 23-035-01.

For comparative purposes, the Division spread the recommended $431,578,182 deferral over 12 months across customer rate classes consistent with the 2020 GRC approved method, resulting in an increased cost of service of 146.57% over the current EBA surcharge rates. Schedule 1 customers under the recommended one-year EBA collection would see a rate increase of 11.82% from its current surcharge rate of 8.06%, totaling 19.88%, this is 146.57% more than the current 8.06% surcharge rate. The comparative results are provided in DPU TABLE 8 below.

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[25] Direct Testimony of Jack Painter, Page 16, Lines 308 – 309.
[26] Utah Code Ann. § 54-7-13.5 (2)(k)(iii)(A).
[27] Direct Testimony of Robert Meredith, Exhibit RMP___(RMM-3).

DPU TABLE 8 **COST OF SERVICE COMPARISON**

Recommended Vs. Proposed

		$431,578,182 Recovery			$454,953,425 Recovery		
Schedule	Current Surcharge	1 Year	Rate Increase	% Increase	2 Year	Rate Increase	% Increase
1	8.06%	**19.88%**	11.82%	146.57%	**10.48%**	2.42%	29.96%
2	8.06%	**19.88%**	11.82%	146.57%	**10.48%**	2.42%	29.96%
2E	8.06%	**19.88%**	11.82%	146.57%	**10.48%**	2.42%	29.96%
3	8.06%	**19.88%**	11.82%	146.57%	**10.48%**	2.42%	29.96%
6	10.70%	**26.37%**	15.68%	146.57%	**13.90%**	3.21%	29.96%
6A	9.94%	**24.50%**	14.57%	146.57%	**12.92%**	2.98%	29.96%
7	5.88%	**14.50%**	8.62%	146.57%	**7.64%**	1.76%	29.96%
8	12.05%	**29.72%**	17.66%	146.57%	**15.66%**	3.61%	29.96%
9	15.06%	**37.14%**	22.08%	146.57%	**19.58%**	4.51%	29.96%
9A	16.49%	**40.67%**	24.18%	146.57%	**21.44%**	4.94%	29.96%
10	10.13%	**24.97%**	14.84%	146.57%	**13.16%**	3.03%	29.96%
11	5.88%	**14.50%**	8.62%	146.57%	**7.64%**	1.76%	29.96%
12	5.88%	**14.50%**	8.62%	146.57%	**7.64%**	1.76%	29.96%
15T	9.49%	**23.40%**	13.91%	146.57%	**12.34%**	2.84%	29.96%
15M	21.12%	**52.08%**	30.96%	146.57%	**27.45%**	6.33%	29.96%
22	15.06%	**37.14%**	22.08%	146.57%	**19.58%**	4.51%	29.96%
23	8.61%	**21.24%**	12.63%	146.57%	**11.19%**	2.58%	29.96%
31	*						
32	*						

*The rate for Schedules 31 and 32 shall be the same as the applicable general service schedule.

The Division has performed a preliminary review of the Company's application for cost recovery. Issues presented herein are provided in support of the Division's recommendation on the Company's filing and proposed interim rate. The Division will have additional details, comments, and recommendations on these and other issues, including the Washington Climate Commitment Act, in its final report.

Although the Division has performed a broad review of the current filing, it makes no judgment regarding the entirety or accuracy of the information. Confidential DPU Exhibit 1 summarizes the Division's comparison of the Company's current Application and supporting documents with the prior year's filing. The variations, issues, and questions discovered during this initial review, not mentioned in this interim rate report, but recorded in DPU Exhibit 1, were determined immaterial to the Company's EBA interim rate request.

Conclusion

Based on the overall body of information as filed and the Division's experience with EBA filings and audits, the Company has made a prima facie showing that the amount of the interim rate increase requested is more likely to reflect actual power costs than current Base rates. [28]

The Division recommends the Commission remove $24,201,822 in collection period interest and reject the Company's proposed 24-month collection period, as these are inconsistent with prior years' filings. Adopting these recommendations would save customers an estimated $12 million in additional interest. A 24-month collection period would also minimize future flexibility, making it more difficult to return to a one-year collection in the absence of significant base rate or market changes. In addition, the Division recommends an increase of $826,579 to the deferral amount to correct an interest calculation. Finally, the Division requests that the Company include in future EBA filings details and calculations related to the Company's EBA deferral adjustments and collections occurring in the deferral year.

After removing the Division's recommended adjustments totaling $23,375,243, $431,578,182 in deferred costs is recommended to be collected over one year on an interim rate basis, from July 1, 2024, through June 30, 2025.

cc: Jana Saba, Rocky Mountain Power
Michele Beck, Office of Consumer Services

[28] Utah Code Ann. § 54-7-13.5 (2)(k)(iii)(B)