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Division of Public Utilities
UTAH DEPARTMENT OF COMMERCE

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Action Request Response

To: Public Service Commission of Utah

From: Utah Division of Public Utilities

Chris Parker, Director
Brenda Salter, Assistant Director
David Williams, Utility Technical Consultant
Matthew Pernichele, Utility Technical Consultant

Date: July 21, 2025

Re: **Docket No. 17-035-40** Application for Approval of a Significant Energy Resource Decision and Voluntary Request for Approval of Resource Decision, New Wind and Transmission Report for CY 2024

Recommendation (Acknowledge)

The Utah Division of Public Utilities ("Division") has reviewed PacifiCorp's ("Company") New Wind and Transmission Report for the Calendar Year 2024 ("2024 Report"). The 2024 Report complies with the requirements of the Public Service Commission of Utah's ("Commission") order approving ("Approval Order")[1] the three wind projects ("Wind Projects") and accompanying transmission project ("Transmission Project") (collectively "Projects") and subsequent orders modifying those requirements ("First Report Order"[2], "2020 Approval Order"[3], and "2021 Approval Order"[4]) (collectively "Reporting Requirements"). The form of the 2024 Report is substantially unchanged from previous submissions of the report that the Commission has acknowledged. The DPU recommends

[1] Docket No. 17-035-40, Order, (June 22, 2018) (note: all citations are to the present docket unless indicated otherwise).
[2] Order on Reporting Requirements, (October 22, 2018).
[3] Order, (July 21, 2021).
[4] Order, (August 1, 2022).

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the Commission acknowledge the 2024 Report.

Issue

The Approval Order directed the Company to file annual reports addressing the cost and performance of various aspects of the projects approved in this docket. The Commission modified the Reporting Requirements in subsequent orders as noted in the Recommendation section above.

The Commission's Order on Reporting Requirements requires the Company to issue the report annually for 10 years to correspond with the duration of the project's production tax credits ("PTC").[5] Subsequent federal legislation has not changed the PTC's 10-year duration. Tab (ii) PTC Benefits of the 2024 Report lists [redacted] as the last date that any of these projects will still receive PTCs.

The nine Reporting Requirements, incorporating the Commission's changes to date, are summarized in Table 1.

[5] Order on Reporting Requirements, at 5 (October 22, 2018).

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Table 1
Docket No. 17-035-40
Annual Reporting Requirements of the Combined Projects
Filed Annually for 10 years, Due on May 25 of each year[6]

Required Information	Duration	Confidentiality
(i) final project costs for each specific project		Confidential
(ii) realized PTC benefits		Confidential
(iii) realized energy benefits		Non-confidential
(iv) transmission costs of the Transmission Projects that are offset by revenues derived from wholesale transmission customers		Non-confidential
(v) payments for any damages, including liquidated damages		Confidential
(vi) contribution to the 230 kV Network Upgrades' total cost from interconnection customers		Confidential
(vii) annual revenue requirement associated with the Aeolus to Bridger/Anticline Line and the incremental transmission revenue resulting from the construction of the line		Non-confidential
(viii) wind operations and maintenance costs associated with the Wind Projects that PacifiCorp owns		Non-confidential
(ix) realized value of RECs sold		Confidential

The Commission's most recent Order[7] made no additional changes to the Reporting Requirements.

The Company filed the 2024 Report on May 22, 2025. That same day, the Commission asked the Division to review RMP's Report for compliance and make recommendations by July 21, 2025. The DPU has reviewed the 2024 Filing for compliance with these requirements and compared it to past years' reports in this docket. The Division also analyzed the Company's answers to data requests filed by the Division and the Office of Consumer Services ("OCS").

[6] *Id*, p.3.
[7] Order, (October 3, 2024).

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Discussion

The 2024 Report is an Excel spreadsheet in the same form as the Company's previous filings in this docket, with a tab corresponding to each of the Reporting Requirements. The 2024 Report incorporates the past filings, adding the 2024 information to the previous reports. The information in each tab is in the same form as past reports and satisfies the corresponding Reporting Requirement as it was approved in past filings.

Jurisdictional Allocation Factors

The Company added a tab labeled Factors to the 2024 report. The Factors tab lists the percentage of project costs and benefits allocated to Utah using the System Generation Factor ("SG Factor") each year for 2020 through 2024. The SG Factor is calculated using the System Capacity Factor ("SC Factor") and System Energy Factor ("SE Factor").[8] The Company recalculates the SG Factor annually to account for changes in the SC and SE Factors. The SC Factor measures a jurisdiction's relative capacity requirement based on its 12-month coincident peaks.[9] The SE Factor is the ratio of a jurisdiction's weather-normalized energy input divided by the weather-normalized energy input of the whole system.[10] The SG Factor is .75*SC+.25*SE.[11] These calculations and their inputs are described in more detail in the 2020 Protocol.

It is unclear whether the SG Factor's heavy weighting of peak usage in the 2020 Protocol still accurately reflects system costs. When appropriate, these allocations should be re-examined to determine if they still accurately allocate costs.

The Factors tab shows Utah's share of the Company's expenses allocated by the SG Factor gradually increasing from 43.66% in 2020 to 45.12% in 2024. This slight increase is a result of Utah's portion of the Company's system using a gradually growing percentage of the system's electricity from 2020 through 2024.

[8] *2020 PacifiCorp Inter-Jurisdictional Protocol*, Docket No. 19-035-42, Appendix C *Definitions of Allocation Factors*, p. 7 (December 3, 2019).
[9] *Id,* p. 6.
[10] *Id.*
[11] *Id,* p. 7.

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Reporting Requirements

i. Final Project Costs for each project.

This tab summarizes the booked total cost of each Wind Project and the Aeolus to Bridger/Anticline transmission project. [redacted]

ii. Realized PTC Benefits.

This tab calculates the value of the Production Tax Credits ("PTC") produced by the Wind Projects. The Wind Projects earn one PTC from the Federal Government for each kWh they produce during their first 10 years of operation. The value of each PTC increased 3.57%, from $0.028/kWh to $.029/kWh in 2024.

Total electricity produced by the three projects in this docket [redacted]

Table 2
Production by Project by Year

	2021 MWh	2022 MWh	2023 MWh	2024 MWh
Cedar Springs	[redacted]	[redacted]	[redacted]	[redacted]
Ekola Flats:	[redacted]	[redacted]	[redacted]	[redacted]
TB Flats:	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

[12] DPU Exhibit 1, *Rocky Mountain Power Response to DPU Data Request 35.2* (June 25, 2025).
[13] *DPU Action Request Response*, at 5 (July 25, 2023).

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[redacted]

Table 3
Actual Production as a Percentage of Projected Production

Year	Cedar Springs	Ekola Flats	TB Flats
2021	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]

In previous versions of this annual report, the Company attributed this [redacted]

Curtailment is when the Company effectively turned the plants off, producing no electricity, when they would otherwise be able to operate. In the 2023 Report, the Company attributed curtailment to [redacted]

In the tab of the 2024 Report labeled (iii) Energy Benefits, the Company values a MWh of electricity from these projects at the monthly market price for either a high load hour (HLH) or low load hour (LLH) minus the integration cost (discussed in iii. Energy Benefits, below). A proforma calculation of the costs of these curtailments using an average annual price per MWh (as reported by the Company), plus the value of PTCs, minus integration cost, values them at between [redacted] (if they all occurred during HLH) and [redacted] (if they all

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[14] *Rick T. Link Confidential workpaper EV2020 Second Supp Results Summary File*, Tab 'Wind Costs', rows 37-40 (Feb. 16, 2018).
[15] *DPU Action Request Response*, at 6 (July 25, 2023).
[16] *Id.*
[17] DPU Exhibit 2, *Rocky Mountain Power Response to DPU Data Request 35.4* (June 25, 2025).

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occurred during LLH).

The Company did not provide details of the times, dates, and amount of electricity curtailed from the Wind Projects, so a more exact estimate of the actual cost of the curtailments is not possible. Significantly, the Company was unable to identify why the Wind Projects were curtailed,[18] raising questions about the Company's efforts to minimize the curtailment of generation with virtually no variable costs.

iii. **Realized Energy Benefits.**

This tab calculates the incremental net power cost savings from the energy produced by the Wind Projects by multiplying the MWh of generation per month per project by the monthly market price (for both High Load Hours (HLH) and Low Load Hours (LLH)) and subtracting Integration Costs of each MWh.

The total amount of electricity generated by the Wind Projects increased slightly in 2024 over 2023, from 2,651,238 MWh to 2,730,149 MWh. This is an increase of 2.5%.

Market prices decreased significantly from 2023 to 2024, with the Wind Projects' output being valued at an average of $82.12 during HLH and $63.19 during LLH per MWh in 2023, and $41.81 and $30.64 in 2024.

Integration Cost is a calculation of the additional costs that variable generation (usually wind and solar) impose on the operation of the power system. Integration Costs predominantly account for the need to have dispatchable backup power to replace an intermittent source when it isn't generating as much as planned.[19] The Company calculates the Integration Cost of wind generation by "multiplying the hourly change in reserve requirements (in MW) by the hourly regulation reserve price in each hour of the year, and then dividing that total by the incremental wind generation over the year."[20]

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[18] *Id.*
[19] National Renewable Energy Laboratory, *Integration of Variable Generation and Cost Causation,* (2012), https://docs.nrel.gov/docs/fy12osti/56235.pdf.
[20] PacifiCorp, PacifiCorp's 2023 Integrated Resource Plan, Amended Final, Volume II, p. 152 (May 31, 2023).

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Table 4

Integration Cost by Year

Year	Integration Cost/MWh
2021	$0.19
2022	$0.27
2023	$0.29
2024	$2.03

The Wind Projects' Integration Costs significantly increased in 2024. The Company explained that it routinely recalculates Integration Costs after a new project has been in service for several years to more accurately account for alternative resources.[21] The Division reviewed the Company's Integration Cost calculation for 2024 and finds it reasonable. The recalculation of the Wind Projects' Integration Cost reduced the Realized Energy Benefit by $4.75 million.

The 2024 Report calculated the Wind Projects Realized Energy Benefit to be $101,867,294, a 48.57% decrease from 2023's $198,053,077. This decrease is primarily due to reduced market prices and increased Integration Costs.

iv. Transmission Costs.

This tab calculates the cost of the Transmission Project to the Company, offset by revenue from wholesale transmission customers. The most significant change in this calculation in the 2024 Report is a $114,518,967 (16.6%) decrease in the Annual Transmission Revenue Requirement, from $688,484,201 in 2023 to $573,966,175 in 2024. The Company explains that this is primarily the result of an approximately $1.3 billion reduction to the administrative and general expense account to correct for accrued wildfire expenses that had been used to calculate the Company's revenue requirement for 2023 but were removed for 2024.[22]

v. Liquidated Damages.

This tab lists any payments to PacifiCorp for damages related to the Projects. The 2024 Report shows [redacted]

[21] *See,* DPU Exhibit 3, *Rocky Mountain Power Response to DPU Data Request 35.6* (June 25, 2025).
[22] DPU Exhibit 4, *Rocky Mountain Power's Response to OCS Data Request 18.2*, (June 25, 2025).

Redacted

[redacted]

vi. 230kv Network Upgrade.

This tab calculates interconnection customers' contribution to the total cost of the Projects' 230 kV Network Upgrades. [redacted]

vii. Aeolus to Bridger/Anticline Revenue Requirement.

This tab calculates the total company and Utah allocated annual revenue requirement for the Aeolus to Bridger/Anticline Line and the offsetting wholesale wheeling revenues it generates. It is otherwise a conventional revenue requirement calculation that accounts for annual and accumulated depreciation and deferred income taxes. The calculation shows no capitalized operations and maintenance expense. The Utah allocation is determined by multiplying the property tax expense by the Gross Plant System Factor (GPS Factor) and all other costs by the SG factor (discussed above). The GPS factor shows a very gradual increase over the reported period, similar to the increases to the SG factor.

viii. Wind Operations and Maintenance.

This tab summarizes operations and maintenance expenses for each of the Wind Projects for the year. In 2024, O&M for the Cedar Springs Wind project exceeded those projected when the projects were proposed ($6,592,865 actual costs vs. $4,197,855 projected). But the other two projects produced less than projected O&M expenses, resulting in a total Wind Project O&M expense for the year that was $16,050,077 compared to the projected $21,309,062, a savings of $5,258,985. This pattern is consistent with that from the previous three annual reports, with some of the Wind Projects occasionally spending more on O&M than projected but the aggregate total O&M for the year being less than the projected total. This is true for all four of the annual reports filed since the Wind Projects became operational in 2021. Responding to a data request from the OCS, the Company stated that

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none of the O&M expenses in this report have been capitalized.[23]

ix. Renewable Energy Credits.

This tab accounts for the RECs earned by the Wind Projects. Tab (ix) RECs, has three tables for each year.

The first shows the number of RECs sold from each project, their vintage, sale price per REC, the total revenue, and the purchaser. Table 4 is a summary showing [redacted]

Table 5
REC Revenue Summary

Year	RECs Sold	Average Price
2021	[redacted]	[redacted]
2022	[redacted]	[redacted]
2023	[redacted]	[redacted]
2024	[redacted]	[redacted]

The next table shows the total number of RECs created by the Wind Projects, the number held to comply with laws in California, Oregon, and Washington, and the number left over. The Company withheld [redacted] of the total RECs generated for California, Oregon, and Washington. The total number of RECs generated reported in tab ix is [redacted]

The final table in this tab shows the total revenue from the RECs sold and the share of the revenue accredited to Utah. This was [redacted] in 2024.

Responding to a data request, the Company explained that the RECs that were not sold or held for compliance do not expire and will be held by the Company (in WREGIS) until they can be sold or otherwise used in the future.[24]

Conclusion

The DPU recommends the Commission approve the 2024 Report because it is complete, consistent with earlier filings, appears to contain no calculation errors, and complies with the

[23] DPU Exhibit 5, *Rocky Mountain Power's Response to OCS Data Request 18.3*, (June 25, 2025).
[24] DPU Exhibit 6, *Rocky Mountain Power's Response to DPU Data Request 35.7*, (June 25, 2025).

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Commission's guidelines.

The Wind Projects' consistent underperformance relative to their originally projected performance and purported value suggests the Commission consider future projections with some skepticism. Given relatively small benefits under certain price and policy scenarios, there is a reasonable likelihood that the Wind Projects are not delivering benefits to customers relative to other scenarios modeled at the time. Particularly when considering variable generation sources, repowering of existing facilities, and purported tax benefits, the Commission should carefully consider benefits analyses and their sensitivities to other factors.[25]

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

[25] See, e.g. Confidential Supplemental Rebuttal Testimony and Surrebuttal Testimony of Dr. Joni S. Zenger, Utah Division of Public Utilities, April 17, 2018, at 3-5; Confidential Supplemental Rebuttal and Surrebuttal Testimony of Daniel Peaco, Utah Division of Public Utilities, April 17,2018, at 71-73.

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DPU EXHIBIT 1

PacifiCorp's Response to DPU Data Request 35.2

17-035-40 / Rocky Mountain Power
June 24, 2025
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DPU Data Request 35.2

Is there any reason to believe that the values in the Final Project Costs (Tab (i)) could change in the future or are the costs final?

Response to DPU Data Request 35.2

The Cedar Springs II (Build Transfer Agreement (BTA)), Ekola Flats, and TB Flats wind resources were completed and placed into service December 8, 2020, December 20, 2020, December 20, 2020 and July 26, 2021. The Aeolus to Bridger/Anticline Line and 230 kilovolt (kV) network upgrades transmission resources were completed and placed into service November 4, 2020 and November 1, 2020. While minor project activities continued through 2022, the Company does not anticipate any further adjustments and considers the Final Project Costs to be final.

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DPU EXHIBIT 2

PacifiCorp's Response to DPU Data Request 35.3

17-035-40 / Rocky Mountain Power
June 24, 2025
DPU Data Request 35.4

DPU Data Request 35.4

Curtailment. Were there any curtailments of the resources that are part of this docket that exceeded 1 MWh?

(1) If so, please explain how much was curtailed and why for each incident of curtailment over 1 MWh.

Response to DPU Data Request 35.4

Yes. In calendar year 2024, economic curtailments that exceeded 1 megawatt-hour occurred for all of the wind resources relevant to this Energy Vision (EV) 2020 compliance filing proceeding, namely Cedar Springs Wind II (BTA), Ekola Flats Wind and TB Flats Wind.

(1) Please refer to the table below which provides approximate calendar year 2024 total economic curtailments for Cedar Springs Wind II (BTA), Ekola Flats Wind and TB Flats Wind:

	Cedar Springs II	**TB Flats**	**Ekola Flats**
2024 Total MWh	-26,977	-53,448	-4,895

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DPU EXHIBIT 3

Response to DPU Data Request 35.6

(1) The integration cost of $0.29 per megawatt-hour ($/MWh) for 2023 was calculated in PacifiCorp's 2019 Integrated Resource Plan (IRP). The integration cost of $2.03/MWh for 2024 was calculated in PacifiCorp's 2021 IRP. Because the IRP model is focused on long-term capacity expansion, the data in the first few years does not have all of the short-term options the Company uses in actual operations. The Company does not report integration costs from the IRP for the first few years if they appear to be skewed by the absence of short-term resource alternatives. While results for 2023 were reported in the 2021 IRP, the results for solar were somewhat elevated, which could be an indication that the results were impacted by the transition from short-term to long-term planning.

(2) For the work papers related to integration costs from the 2019 IRP, please refer to Attachment DPU 35.6-1, specifically row 78 of tab "Wind 2030" in file "App F - Flex Study PaR results.xlsx", as well as Confidential Attachment DPU 35.6-2. For the work papers related to integration costs from the 2021 IRP, please refer to Attachment DPU 35.6-3 and Confidential Attachment DPU 35.6-4.

Confidential information is provided subject to Public Service Commission of Utah (UPSC) Rules R746-1-601–606.

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DPU EXHIBIT 4

17-035-40 / Rocky Mountain Power
June 25, 2025
OCS Data Request 18.2

OCS Data Request 18.2

RMP Attachment 1 – RMP's New Wind and Transmission Report for CY 2024 filed on May 22, 2025 in this docket. Refer to Tab (iv) Transmission Costs. Line 1, Annual Transmission Revenue Requirement in 2024 dropped to $573,966,174 from $668,484,201 in 2023. This is a 14% decrease. Please explain the reasons for this large decrease. In addition, please discuss and quantify any categories of the revenue requirement that saw large increases from 2023 to 2024.

Response to OCS Data Request 18.2

The primary driver to the large drop in the revenue requirement in 2024 from 2023 based on comparisons between the 2024 formula rate true-up compared to the 2023 formula rate true-up as posted on the Open Access Same-Time Information System (OASIS) is approximately $1.3 billion reduction in administrative and general (A&G) expenses. This decrease is the result of lower 2024 wildfire accruals compared to the accruals recorded in 2023. In addition, revenue credits in 2024 increased approximately $40.2 million compared to 2023, which reduces the annual revenue requirement, primarily due to increases in short-term revenue credits and lower rate base, resulting in a smaller revenue requirement benefit on rate base.

Partially offsetting the decreases to the annual revenue requirement is higher rate base in 2024 of approximately $492 million, higher depreciation expense of approximately $7.2 million, higher income taxes of $12.8 million increasing the revenue requirement and higher interest on network upgrade facilities of approximately $4.7 million.

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DPU EXHIBIT 5

17-035-40 / Rocky Mountain Power

June 25, 2025

OCS Data Request 18.3

OCS Data Request 18.3

RMP Attachment 1 – RMP's New Wind and Transmission Report for CY 2024 filed on May 22, 2025 in this docket. Refer to Tab (viii) of the 2024 Report, Wind O&M Costs for Cedar Springs, Ekola Flats and TB Flats. Please provide:

(a) The amount of O&M for each project in 2024 that was capitalized. Please provide a table similar to the one in Tab (viii) that includes columns for Expensed O&M and Capitalized O&M.

(b) The wind O&M costs assumed in RMPs last general rate case, in Docket No. 24-035-04, for these three projects. Please break out by amounts expensed versus capitalized.

(c) For each wind project's total 2024 O&M (both expensed and capitalized), please breakout the dollar amounts into major categories or types of maintenance performed, for example (but not limited to) inspections, blade repair, gearbox maintenance or replacement, generator maintenance or replacement, etc.

Response to OCS Data Request 18.3

Referencing the Company's compliance filing for calendar year 2024, specifically confidential file "17-035-40 RMP PROPRIETARY Attachment 1 for 2024 5.23.25", tab "(viii) wind O&M", the Company responds as follow:

(a) None of the O&M amounts in the referenced table were capitalized. The values provided in the table are operations and maintenance (O&M) costs.

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(b) None of the O&M amounts in the 2024 general rate case (GRC) proceeding, Docket 24-035-04, were capitalized. The values provided are O&M costs.

	2025 Utah GRC
EKOLA FLATS WIND PLANT	$ 3,111,375
TB FLATS WIND PLANT	$ 6,817,120
CEDAR SPRINGS WIND PLANT	$ 4,067,041
TOTAL	$ 13,995,535

(c) Please refer to Confidential Attachment OCS 18.3 which provides O&M costs according to FERC Account categories.

Confidential information is provided subject to Public Service Commission of Utah (UPSC) Rules R746-1-601 et. seq

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DPU EXHIBIT 6

17-035-40 / Rocky Mountain Power

June 24, 2025 DPU

Data Request 35.7

DPU Data Request 35.7

Renewable Energy Credits

(1) What does the Company do with RECs that are not used for compliance or sold?

(2) Do the RECs from the projects in this docket expire? If so, in how long after they are generated?

Response to DPU Data Request 35.7

(1) The Company holds (banks) renewable energy credits (REC), that are not sold or used for compliance, in the Western Renewable Energy Generation Information System (WREGIS).

(2) RECs from the wind projects relevant to this Energy Vision (EV) 2020 compliance filing proceeding, namely Cedar Springs Wind II (BTA), Ekola Flats Wind and TB Flats Wind, do not expire.