Rocky Mountain Power
Docket No. 25-035-01
Witness: Jack Painter

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Direct Testimony of Jack Painter

May 2025

Q. Please state your name, business address, and present position with PacifiCorp d/b/a Rocky Mountain Power ("Rocky Mountain Power" or the "Company").

A. My name is Jack Painter, and my business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My title is Net Power Cost Adviser.

I. QUALIFICATIONS

Q. Please describe your education and professional experience.

A. I received a Bachelor of Arts degree in Business Administration with a Finance major from Washington State University in 2007. I have been employed by PacifiCorp since 2008 and have held positions in the regulation and jurisdictional loads departments. I joined the regulatory net power costs group in 2019 and assumed my current role as a Net Power Cost Adviser in 2024.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have previously provided testimony to the public service commissions in Utah, Idaho, Wyoming, Oregon, Washington, and California.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony in this proceeding?

A. My testimony presents and supports the Company's calculation of the Energy Balancing Account ("EBA") deferral for the 12-month period from January 1, 2024, through December 31, 2024 ("Deferral Period"). More specifically, I provide the following:

- Details supporting the calculation of the Company's request to recover $471.6 million for excess EBA-related costs including interest, an adjustment for sales made to a special contract customer, Utah situs-assigned resource adjustments included in the EBA, an adjustment to reflect the Public Service Commission of Utah's ("Commission") order in the 2024 EBA,[1] an adjustment to include the remaining uncollected balance from the 2023 EBA,[2] an adjustment to credit the EBA with 33 percent of Schedule 60 revenues from the Electric Vehicle Infrastructure Program ("EVIP"); and an adjustment to credit the EBA with additional Production Tax Credits from calendar year 2023 that were calculated in the Company's tax filing, which occurred after the 2024 EBA application.

- Discussion of the main differences between adjusted actual net power costs ("Actual NPC") and net power costs in rates ("Base NPC"); and
- Discussion about the Company's participation in the Western Energy Imbalance Market ("WEIM") with the California Independent System Operator ("CAISO") and the benefits from the WEIM that are passed through to customers.

Q. Are any other witnesses presenting testimony specifically for the EBA and Electric Service Schedule No. 94 ("Schedule 94") in this case?

A. Yes. Company witness Robert M. Meredith, Director, Regulation, provides testimony on the proposed Schedule 94 rates.

III. SUMMARY OF THE EBA DEFERRAL CALCULATION

Q. Please summarize the Company's EBA application.

A. The Company's application requests recovery of $471.6 million in deferred costs,

[1] *Rocky Mountain Power's Application for Approval of the 2024 Energy Balancing Account*, Docket No. 24-035-01, Order (Feb. 25, 2025) ("2024 EBA Order").

[2] *Rocky Mountain Power's Application for Approval of the 2023 Energy Balancing Account*, Docket No. 23-035-01, Order (Feb. 23, 2024) ("2023 EBA Order").

comprised of $474.9 million of EBA-related costs, a credit of $24.9 million for sales made to a special contract customer, a $9.2 million adjustment for Utah situs-assigned resources, a credit of $24.2 million to reflect the 2024 EBA Order, a $0.2 million adjustment to reflect the remaining balance from the 2023 EBA, a credit of approximately $0.1 million for EVIP Schedule 60 revenue, and a credit of approximately $0.4 million to update 2023 Production Tax Credits and approximately $36.8 million of interest. The Company proposes to collect the deferred balance over 12 months beginning July 1, 2025.

Q. Are there any changes to the EBA deferral calculation?

A. Yes. Changes have been included as part of the EBA calculation for the following items:

- Inclusion of revenues from Schedule 60 associated with the EVIP.
- Inclusion of the interest accrued through the rate effective period from July 1, 2025 through June 30, 2026.

IV. EBA DEFERRAL CALCULATION

Q. Please describe the calculation of the EBA deferral included in this filing.

A. Table 1 below provides a summary of the total EBA deferral and a breakdown of the individual components of the EBA. Additionally, Exhibit RMP___(JP-1) presents the detailed calculation of the EBA deferral on a monthly basis.

Table 1
Annual EBA Calculation

Calendar Year 2024 EBA Deferral		*Exhibit RMP___(JP-1) Reference*
Actual EBA ($/MWh)	$ 37.05	*Line 6*
Base EBA ($/MWh)	18.81	*Line 12*
$/MWh Differential	**$ 18.24**	
Utah Sales (MWh)	26,070,633	*Line 5*
EBA Deferrable*	$ 474,911,772	*Line 14*
Special Contract Customer Adjustment*	(24,903,951)	*Line 17*
Utah Situs Resource Adjustment*	9,220,126	*Line 18*
Total Deferrable	$ 459,227,947	*Line 19*
2023 EBA Collection True-Up	$ 238,367	*Line 25*
2024 EBA Final Order Adjustment	(24,244,080)	*Line 26*
Interest Accrued through December 31, 2024	12,324,881	*Line 27*
Interest Accrued January 1, 2025 through March 31, 2025	5,995,373	*Line 29*
Interest Accrued April 1, 2025 through June 30, 2025	6,144,341	*Line 30*
Interest Accrued through Rate Effective Period July 1, 2025 through June 30, 2026	12,376,556	*Line 31*
EVIP Revenue	(51,052)	*Line 24*
2023 PTC Update	(397,024)	*Line 23*
Requested EBA Recovery	**$ 471,615,308**	*Line 32*

* *Calculated monthly*

The EBA deferral of $471.6 million is calculated as the difference between the Actual NPC, Production Tax Credits ("PTCs") and wheeling revenue and the Base NPC, PTC's and wheeling revenue, as established in the 2020 general rate case.[3] The calculation of the monthly amount debited or credited into the EBA Deferral Account is based on the following formula:

$$EBA\ Deferral_{Utah,month} =$$

$$\left[\left(Actual\ EBAC_{\frac{Utah,month}{MWh}} - Base\ EBAC_{\frac{Utah,month}{MWh}}\right) \times Actual\ MWh_{Utah,month}\right]$$

[3] *Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations,* Docket No. 20-035-04, Order (Dec. 30, 2020).

Q. What revenue requirement components are included in the EBA deferral calculation?

A. The EBA deferral calculation consists of three revenue requirement components: NPC, PTCs, and wheeling revenue. NPC are defined as the sum of fuel expenses, wholesale purchase power expenses, and wheeling expenses, less wholesale sales revenue. PTCs are credits the Company receives for generation at certain Company-owned wind facilities that are included as an offset to the Company's federal income taxes and reduce net power costs for rate-making purposes. Wheeling revenue includes amounts booked to Federal Energy Regulatory Commission ("FERC") account 456.1 and revenues from transmission of electricity of others. Collectively, these three components are known in the Company's EBA tariff, Schedule 94, as Energy Balancing Account Costs ("EBAC").

Q. How are the Utah-allocated Actual NPC calculated?

A. Utah-allocated Actual NPC are calculated in three steps. First, unadjusted actual NPC are established on a total-Company basis. Second, adjustments are made to the unadjusted actual NPC to apply certain regulatory adjustments and to remove out-of-period accounting entries. Third, the adjusted total-Company Actual NPC are allocated to Utah based on the 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol.

Q. What were the total-Company adjusted Actual NPC for the Deferral Period and how were they determined?

A. The total-Company adjusted Actual NPC in the Deferral Period were approximately $2.597 billion. This amount captures all components of NPC as defined in the Company's GRC proceedings and modeled by the Company's power cost production model. Specifically, it includes amounts booked to the following FERC accounts:

Account 447 –	Sales for resale, excluding on-system wholesale sales and other revenues that are not modeled in GRID
Account 501 –	Fuel, steam generation; excluding fuel handling, start-up fuel (gas and diesel fuel, residual disposal) and other costs that are not modeled in GRID
Account 503 –	Steam from other sources
Account 547 –	Fuel, other generation
Account 555 –	Purchased power, excluding the Bonneville Power Administration residential exchange credit pass-through if applicable
Account 565 –	Transmission of electricity by others

Q. Does the Company have any updates to the potential FERC accounting change that was noted in your testimony in the 2023 EBA proceeding?

A. Yes. On June 29, 2023, the FERC issued Order No. 898 (Docket No. RM21-11-000), Accounting and Reporting Treatment of Certain Renewable Energy Assets, to change the accounting required for certain types of costs that have been previously booked to FERC Account 555 to be booked to FERC account 509.[4]

Q. Does FERC Order No. 898 impact the current EBA?

A. No. The change from FERC account 555 to FERC account 509 for these costs becomes effective January 1, 2025.

[4] *File Rule*, 183 FERC ¶ 61,205, Docket No. RM21-11-000 (Jun. 29, 2023) *available at* https://www.ferc.gov/media/order-no-898.

Q. Did the Company update the accounts listed in Schedule 94 as recommended by the Division of Public Utilities in the 2023 EBA?

A. Mr. Meredith presents the Company's revisions to Schedule 94, which includes an update to the accounts listed for inclusion or exclusion from the EBA as recommended by Division witness Gary Smith.[5]

Q. What adjustments are made to Actual NPC and why are they needed?

A. The Company adjusts Actual NPC to reflect the ratemaking treatment of several items, including:

- Out of period accounting entries booked in the Deferral Period that relate to operations prior to implementation of the EBA in October 2011;
- Buy-through of economic curtailment by interruptible industrial customers;
- Revenue from a contract related to the Leaning Juniper wind resource;
- Costs for situs-assigned resources/programs in Utah and Oregon;
- Situs assignment of Reasonable Energy Price adjustments to QF's;
- Coal inventory adjustments to reflect coal costs in the correct period; and
- Legal fees related to fines and citations included in the cost of coal.

Additional details regarding each of these adjustments and the impact on NPC are provided in Additional Filing Requirement 15.

Q. What allocation methodology did the Company use to calculate the EBA Deferral Account balance?

A. The 2020 GRC set the Base NPC effective January 1, 2021, in Docket No. 20-035-04 using the Commission Order Method, which was originally approved by the

[5] *Rocky Mountain Power's Application for Approval of the 2023 Energy Balancing Account*, Docket No. 23-035-01, Direct Testimony of Gary Smith for the Division of Public Utilities at 8-9, (Nov. 7, 2023).

Commission in Docket No. 09-035-15. Exhibit RMP___(JP-1) calculates the EBA deferral using the Commission Order Method for the entire Deferral Period.

Q. Does the calculation of the EBA deferral include carrying charges?

A. Yes. In accordance with the Commission's orders dated March 2, 2011, and February 16, 2017, in Docket No. 09-035-15, carrying charges accrue on the monthly EBA deferral. Effective January 1, 2020, the carrying charge is the customer deposit rate for Residential and Non-residential Deposits in Electric Service Schedule No. 300. Carrying charges accrue monthly during the Deferral Period, the review period, and will continue to accumulate during the collection period. While carrying charges have always accrued during the collection period, the Company has not previously included them in the initial request until the 2024 EBA application filed on May 1, 2024. In that docket, the Company also proposed a rate effective period of 24 months versus 12 months for rate mitigation. In its preliminary review, the Division of Public Utilities ("DPU") noted this was a departure from past practice and stated it did not have enough information to understand the underlying assumptions and details for the interest calculation during the collection period. The interim rates order in the 2024 EBA approved a 12-month collection period without inclusion of interest through the period to be consistent with prior years filings. The Company is requesting this change again as it reflects a more accurate rate design. The estimated impact of carrying charges during the rate effective period of July 1, 2025 through June 30, 2026 is included in the EBA calculation. To address the DPU's concerns, the supporting calculation is provided in Additional Filing Requirement 21.

Q. Please describe the impact of the special contract customer in the EBA.

A. The special contract customer pays rates specified in the contract and is not subject to new EBA rates approved on or after December 1, 2016. The NPC associated with serving the special contract customer are embedded in Actual NPC. As Utah tariff customers benefit from the special contract remaining on the Company's system and paying a portion of the total revenue requirement, the EBA deferral amount associated with the special contract customer is shared among Utah tariff customers. Additionally, a certain portion of the sales to the special contract customer are at a price different than NPC in base rates, and an adjustment is made to the EBA in which the Utah tariff customers share the variance between the contract price and Base NPC with the Company.

Q. Please describe the adjustment for sales made to a special contract customer.

A. Per the stipulation in Docket No. 16-035-33, the EBA includes an adjustment for certain sales made to the special contract customer. The adjustment calculates monthly the difference between the average monthly contract price paid and NPC in base rates ("Special Contract Differential"). The Special Contract Differential is then multiplied by the megawatt-hour ("MWh") sales to the special contract customer to calculate the dollar amount of the variance. The difference is then subject to a symmetrical deadband of $350,000. For the 2025 EBA, the adjustment for sales made to a special contract customer is a $24.9 million credit.

V. TREATMENT OF SITUS-ASSIGNED RESOURCES

Q. What are situs-assigned resources?

A. Situs-assigned resources are renewable resources that the Company acquired on behalf of either individual states or customers in order to serve part or all of their energy needs by a renewable resource. Both the costs and benefits for these resources are situs-assigned to the state of origin. Non-participating states should not bear higher costs for these resources.

Q. Which resources or programs are considered situs-assigned?

A. There are currently twelve resources or programs that are situs-assigned, with eight in Utah and four in Oregon. The Utah situs-assigned resources or programs are Pavant III Solar for the Utah Subscriber Solar Program, Electric Service Schedule No. 136 Transition Program for Customer Generators ("Schedule 136"), Electric Service Schedule No. 137 Net Billing Service for Customer Generators ("Schedule 137"), Amor IX/Soda Lake Geothermal and Castle Solar under Electric Service Schedule No. 32 ("Schedule 32"), and Cove Mountain Solar 2, Graphite Solar, Appaloosa Solar 1A and 1B, Rocket Solar, Horseshoe Solar, and Elektron Solar under Electric Service Schedule No. 34 ("Schedule 34"). The Oregon situs-assigned resources or programs are Black Cap Solar, Old Mill Solar, Oregon Community Solar, and the Oregon Solar Incentive Plan.

Q. How does the company treat situs-assigned resources in the EBA?

A. The Company uses either the actual cost or the mark-to-market calculation, whichever is lower for NPC allocation purposes. This treatment will ensure that non-participating states will not pay costs higher than actual costs and only the costs that are above market will be situs-assigned to state of origin.

Q. Are there any exceptions to the changes the Company has made?

A. Yes. Black Cap Solar in Oregon is a Company leased resource that has continued the sole use of the mark-to-market calculation because there is no Power Purchase Agreement ("PPA") costs in NPC. Additionally, because the Utah Subscriber Solar Program and both Utah Schedule 32 and Schedule 34 resources, except Elektron Solar, are paid entirely by the respective customers, the lower of actual cost or market results in zero PPA costs. While the PPA costs for the Utah Subscriber Solar Program and most of the Schedule 32 and Schedule 34 resources are zero, there are specific program or contractual costs situs-assigned in the EBA discussed later in my testimony.

Q. Please describe the Utah Situs-Assigned Resource Adjustment.

A. The Utah Situs-Assigned Resource Adjustment accounts for the Utah situs costs of certain resources and expenses, namely the Utah Subscriber Solar Program, Schedule 136, Schedule 137, the Western Energy Imbalance Market ("WEIM") Body of State Regulators ("BOSR") fees charged for commission related work as a participant in the WEIM, and the Western Power Pool ("WPP") Committee of State Representatives ("COSR") and Western Resource Adequacy Program ("WRAP") implementation costs and program coordination services.

Q. Please describe the Utah Subscriber Solar Program.

A. The Commission approved the "Subscriber Solar Program Rider - Optional" Electric Service Schedule No. 73 ("Schedule 73"), effective March 28, 2016, which enables participating Utah customers to purchase electricity from a specific utility-scale solar resource. Customers can elect to purchase blocks of energy at a set amount each month, and the value of any excess, unused block energy is rolled forward to future months. Participating blocks of energy purchased are subject to rates specific to Schedule 73 and are not subject to the EBA adjustment rate schedule changes (Schedule 73, Special

Condition 15).

Q. Please describe the situs-assigned adjustment to the EBA for the Utah Subscriber Solar Program Resource.

A. Under the stipulation in Docket No. 15-035-61, the solar resource is included as a Utah-situs resource in net power costs.[6] The generation costs of the solar resource are compared to the generation charges paid by solar subscriber customers. The difference is either recovered from or credited back to Utah customers through the EBA. In addition, there are no load adjustments and no change in allocation factors due to the program. The EBA adjustment for Subscriber Solar is a cost of $0.1 million.

Q. Please describe Schedule 136 Transition Program and Schedule 137 Net Billing for Customer Generators.

A. In Docket No. 14-035-114, the Commission approved Schedule 136, effective November 15, 2017. In Docket No. 17-035-61, the Commission approved Schedule 137, effective October 31, 2020. Both programs enable 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, which measures the difference between the electricity supplied by the Company and the electricity generated by an eligible customer-generator.

Q. Please describe the situs-assigned adjustment to the EBA for the Schedule 136 and Schedule 137 costs.

A. The cost difference between export credits to eligible customers and the market value

[5] *In the Matter of the Application of Rocky Mountain Power for Approval of its Subscriber Solar Program (Schedule 73)*, Docket No. 15-035-61, Order Approving Amended Settlement Agreement, Exhibit A at 7 (Oct. 21, 2015).

of the exports is recovered from Utah customers through the EBA using the lower of cost or market treatment described above. The EBA adjustment for Schedule 136 costs is $4.4 million and for Schedule 137 costs is $4.2 million.

Q. Please describe the situs-assigned adjustment to the EBA for the fees associated with the WEIM BOSR, WPP COSR, and WPP WRAP.

A. The WEIM BOSR fee supports the BOSR's expenses and supports the body's goal that consistent, and informed regulator engagement on regional market operations and developments is crucial to efficient and sustainable markets that deliver public benefits. The Utah allocated cost in the EBA is $47,090. The WPP WRAP and its state represented committee, COSR, is the regional resource adequacy initiative that is being implemented by many utilities and power producers across the west to ensure that the region is better able to plan for its regional resource adequacy needs. The Utah allocated cost in the EBA is $496,624 for the WRAP and $21,690 for the COSR. The WEIM BOSR and WPP WRAP fees were approved by the Commission for inclusion in the EBA in Docket No. 22-035-01. The Company is proposing to include the WPP COSR fees for calendar year 2024 in the EBA with the WPP WRAP costs, which have been included in base rates in the Company's most recent GRC. If the GRC is approved with these costs in base rates, the costs will no longer be included as a true-up in future EBAs.

Q. What is the WPP COSR?

A. "The Committee of State Representatives ("COSR") is a standing committee of the Western Resource Adequacy Program ("WRAP"), a first-of-its-kind reliability program in the West operated by the Western Power Pool ("WPP"). The WRAP tariff was approved by the Federal Energy Regulatory Commission ("FERC") at the beginning of 2023, and the COSR was established soon after in April 2023 in accordance with the WRAP Bylaws. The COSR aims to support state and provincial engagement in the WRAP and share those valuable perspectives on pertinent program matters. The COSR will advise the WPP Board of Directors, Program Review Committee ("PRC"), Resource Adequacy Participants Committee ("RAPC"), any working groups or task forces, and the FERC on matters related to WRAP governance, program design, and operations. The COSR is composed of one representative from each state or provincial jurisdiction that regulates at least one Participant. State and provincial representatives are nominated by the Chair or President of their respective public utility commissions and may include representatives from the state or provincial energy offices or state or provincial funded consumer advocates. The COSR operates in a public setting and welcomes other regional stakeholders to attend committee meetings to better foster engagement and collaboration."[7]

Q. Please describe the situs-assigned adjustment to the EBA for Schedule 32 and Schedule 34 excess generation purchases.

A. Schedule 32 and Schedule 34 are unique retail service options available to any customer who would otherwise qualify for Electric Service Schedule Nos. 6, 8, or 9 that desires to receive all or part of its electricity from a renewable energy facility. This allows the Company to meet its customers' renewable energy goals while protecting the Company's other customers from the financial impacts of another customer's preference. Purchase power agreement costs and generation from renewable energy

[7] More information on the COSR is available at: https://www.westernenergyboard.org/cosr/.

facilities for the customer are removed from NPC in the EBA and any excess generation is purchased at Electric Service Schedule No. 37 avoided costs rates. Total-Company Schedule 32 and Schedule 34 excess generation costs in the EBA are $9.7 million and situs-assigned costs are zero under the lower of cost or market treatment.

Q. Please describe the new adjustment to include Schedule 60 revenues in the EBA associated with the EVIP.

A. The Company's EVIP was established through a Settlement Stipulation that was approved by the Commission on December 20, 2021.[8] The Settlement Stipulation specified that thirty-three percent of the revenue collected from Company-owned electric vehicle charging infrastructure through Schedule 60 would be credited to Utah customers in the EBA.[9] The Company-owned charges began operating in October 2024 and a credit of $51,052 is included in the EBA in accordance with the terms of the Settlement Stipulation.

VI. DIFFERENCES IN NPC

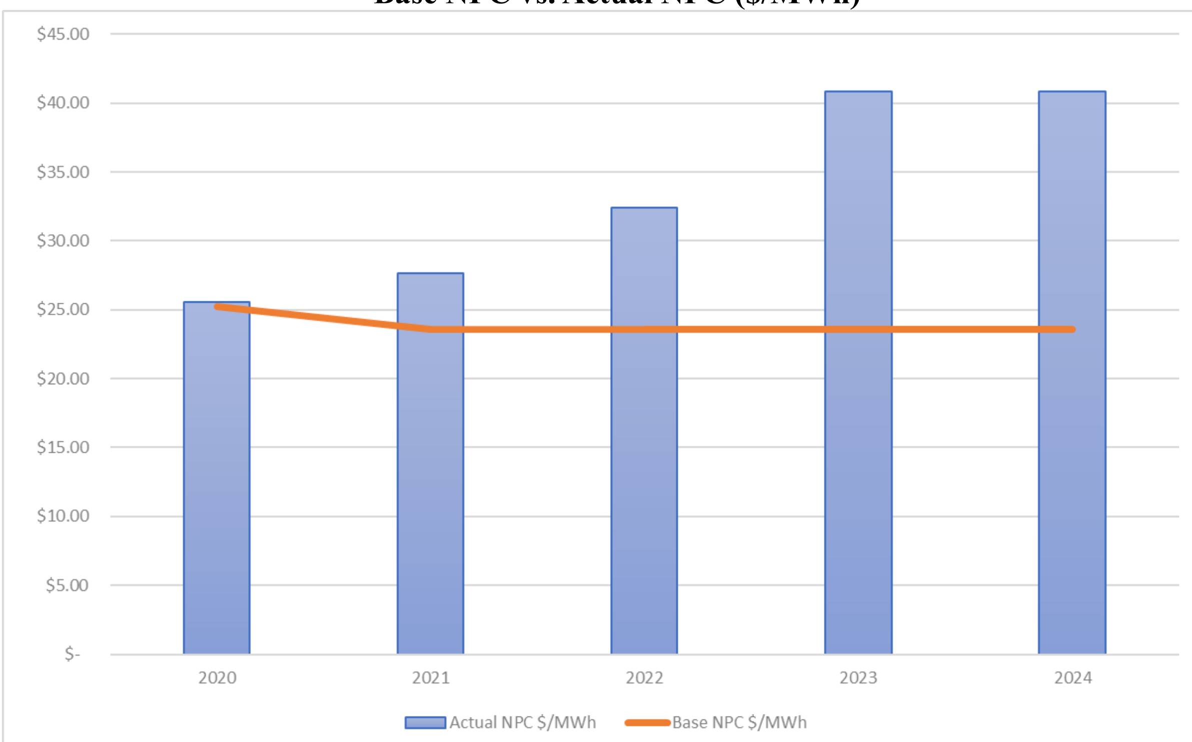
Q. Please describe the Base NPC the Company used to calculate the NPC component of the EBA deferral.

A. The Base NPC for the 2025 EBA were set in the 2020 GRC and became effective January 1, 2021. Base NPC used a test period of 12 months from January 2021 through December 2021 and set total-Company Base NPC $23.61/MWh. Based upon a normalized forecast and perfect operating conditions, actual operating and market conditions have changed since the Base NPC were established. The Company operates

[8] *Application of Rocky Mountain Power for Approval of Electrical Vehicle Infrastructure Program,* Docket No. 20-035-34, Order Approving Settlement Stipulation (Dec. 20, 2021).
[9] *Application of Rocky Mountain Power for Approval of Electrical Vehicle Infrastructure Program,* Docket No. 20-035-34, Settlement Stipulation at 8-9 (Nov. 17, 2021).

its system on a least-cost economic dispatch model for its customers and it is important to note that Base NPC are set for ratemaking purposes only, not the management of actual system operations, nor would it be prudent to do so. Figure 1 below illustrates how Base NPC have been fairly static over time, while Actual NPC has increased significantly.

Figure 1
Base NPC vs. Actual NPC ($/MWh)



Q. On a total-Company basis, what was the difference between Actual NPC and Base NPC for the Deferral Period?

A. On a total-Company basis, Actual NPC for the Deferral Period was $40.84/MWh, approximately $17.23/MWh more than Base NPC for the Deferral Period. Table 2 provides a high-level summary of the difference between Base NPC and Actual NPC by category on a total-Company basis.

Q. What is the Actual NPC $/MWh difference between the current Deferral period and calendar year 2023?

A. From a $/MWh perspective, Actual NPC for the Deferral Period was $40.84/MWh while calendar year 2023 Actual NPC for the Deferral Period was $40.83/MWh, an increase of $00.01/MWh or 0.04%.

Table 2
Net Power Cost Reconciliation

Net Power Costs $	Actual	Base	Variance
Wholesale Sales	106,724,822	223,178,425	(116,453,603)
Purchased Power	1,421,024,233	600,690,780	820,333,453
Coal	527,475,934	602,628,592	(75,152,657)
Gas	571,862,902	299,136,021	272,726,880
Other	183,618,646	151,248,344	32,370,302
Total $	**$2,597,256,893**	**$1,430,525,312**	**$1,166,731,582**
Net Power Costs GWh	**Actual**	**Base**	**Variance**
Wholesale Sales	1,964	7,042	(5,079)
Purchased Power	20,595	13,808	6,787
Coal	18,225	28,094	(9,869)
Gas	16,942	14,428	2,514
Other	9,793	11,292	(1,499)
Total GWh	**63,591**	**60,580**	**3,011**
Net Power Costs $/MWh	**Actual**	**Base**	**Variance**
Wholesale Sales	$54.35	$31.69	$22.66
Purchased Power	$69.00	$43.50	$25.50
Coal	$28.94	$21.45	$7.49
Gas	$33.75	$20.73	$13.02
Other	$18.75	$13.39	$5.36
Total $/MWh	**$40.84**	**$23.61**	**$17.23**

Q. What are the main drivers of NPC in 2024?

A. For 2024, the main drivers of increased NPC were coal fuel supply constraints, increased market power and natural gas prices, the conversion of Jim Bridger Unit 1 and Unit 2 from coal to natural gas, the decommissioning of the Company's hydro generating facilities on the Klamath river, and extreme weather events, all of which are discussed with further detail in my testimony below. Coal supply constraints which began at the end of calendar year 2022, continued through the first part of 2024. Market power prices and natural gas prices have risen sharply since 2021. Changes to the Company's dispatchable resources with the Jim Bridger conversion and Klamath river decommissioning impact overall system operations and NPC through lost mega-watt hours. Extreme weather impacts while small in duration have exponential impacts to NPC due to spiking market prices and demand. These drivers have an overarching influence on all components of the Company's actual system operations through its least cost economic dispatch model.

Q. Please explain the changes in wholesale sales revenue.

A. Wholesale sales volumes declined relative to Base NPC due to an increase in total Company load combined with coal supply constraints and decreased hydro generation. When actual market conditions differ from normalized forecast conditions in the power cost production model, the opportunities for the Company to sell excess generation to the market are limited. Additionally, as market power prices and loads increase simultaneously, wholesale sales volumes decrease as the Company serves its load through its own generation. While the average price of actual wholesale market transactions, represented in the power cost production model as short-term firm and system balancing sales, was $61.94/MWh, or 94 percent higher than the average price in Base NPC, actual wholesale market volumes were 5,431 gigawatt-hours ("GWh"), or 81 percent, lower than Base NPC. In order to achieve a more accurate level of wholesale sales volumes, the Company proposed enhancements to its power cost production modeling in the pending general rate case.

Q. Please explain the changes in purchased power expense.

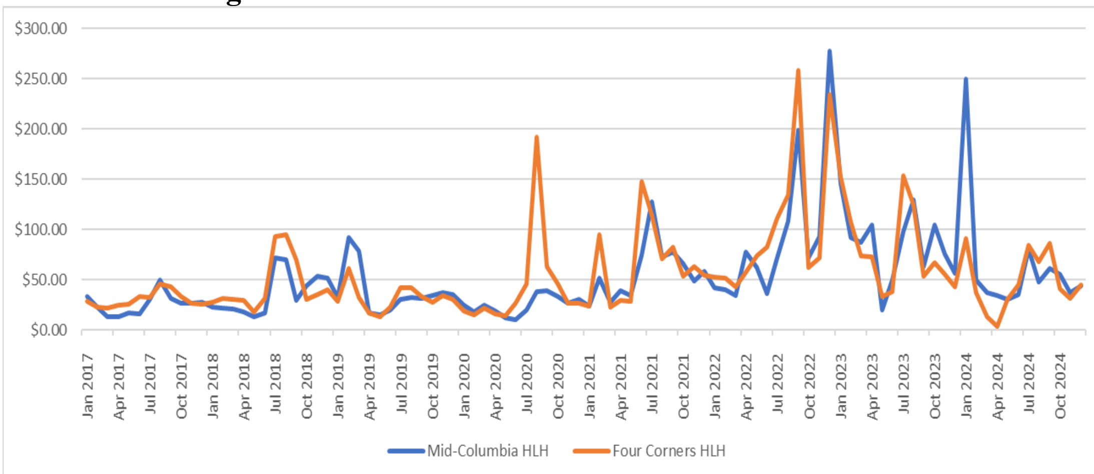
A. On a dollar per megawatt-hour basis, actual market purchase transactions increased from $17.17/MWh in Base NPC to $114.86/MWh, or 569 percent and actual market purchase volumes increased by 4,814 GWh or 136 percent higher than Base NPC.

The average monthly price of market transactions at the Mid-Columbia and Four Corners market hubs has risen significantly since 2021. Between 2016 and 2020, the average monthly Heavy Load Hour ("HLH") market price at the Mid-Columbia market hub was $29.27/MWh and $35.11/MWh at the Four Corners market hub while the average monthly HLH market price in 2024 was $63.45/MWh and $47.87/MWh respectively. Table 3 and Figure 2 illustrate these significant market price increases impacting 2023 NPC.

Table 3
Average HLH Mid-Columbia & Four Corners Market Price

Year	Mid-C HLH Average	Four-C HLH Average
2016-2020	$29.27	$35.11
2021	$58.36	$65.42
2022	$92.75	$102.59
2023	$85.51	$81.12
2024	$63.45	$47.87

Figure 2
Average HLH Mid-Columbia & Four Corners Market Price



Q. Please explain the changes in coal fuel expense.

A. As discussed in my testimony above, coal supply shortages, primarily at the Hunter and Huntington plants, that began in the fourth quarter of 2022 and extended into mid-2024, had a significant impact on the Company's coal generating resources and total system operations. Due to overall lower coal fuel availability and newly executed coal contracts in 2024, the Company had to adjust its overall system operations through increased natural gas resource output and reduced wholesale sales. Total coal fuel expense decreased because coal generation volume was 9,869 GWh, or 35 percent lower than Base NPC as presented in Table 4.

Table 4
Coal Generation

Year	Base GWh	Actual GWh	Variance	Percent
2021 EBA	28,094	31,590	3,496	12%
2022 EBA	28,094	28,391	297	1%
2023 EBA	28,094	21,951	(6,143)	(22%)
2024 EBA	28,094	18,225	(9,869)	(35%)

The coal supply shortages and new coal contracts also increased the average cost of coal generation from $21.45/MWh in Base NPC to $28.94/MWh in the Deferral

Period. Overall, the lower generation volume resulted in a decrease of $75 million in coal fuel expense, but the coal supply limitations and new contracts impacted all other aspects of the Company's system operations and net power costs in 2024.

Q. Please describe the changes in natural gas fuel expense.

A. With a reduction in coal generating resource output in 2024, the Company increased output at its natural gas generating resources. While natural gas prices and the average cost of natural gas generation are higher than Base NPC, the price for operating the Company's natural gas generating resources was more economic than market power purchases on average. Overall, the total natural gas fuel expense in Actual NPC increased due to an increase in the average cost of natural gas generation from $20.73/MWh in Base NPC to $33.75/MWh in the Deferral period and an increase in gas generation volumes of 2,514 GWh (17 percent). Table 5 below shows how gas generation volumes have increased since 2021.

Table 5
Gas Generation

Year	Base GWh	Actual GWh	Variance	Percent
2021 EBA	14,428	13,312	(1,116)	(8%)
2022 EBA	14,428	13,686	(742)	(5%)
2023 EBA	14,428	14,050	(378)	(3%)
2024 EBA	14,428	16,942	2,514	17%

Q. Please describe how the Jim Bridger units 1 and 2 coal to gas conversion impacted NPC.

A. Jim Bridger units 1 and 2 were taken offline at the end of December 2023 for their conversion from coal fired to natural gas fired generating units. Unit 1 was returned to service on 4/16/2024 and Unit 2 was returned to service on 3/12/2024. The natural gas conversion impacted the overall lower coal generation volumes and increased market purchase volumes while also contributing to increased natural gas generation volumes when the units came back online. Between January 2024 and April 2024, 1,039 GWh were lost, which increased NPC by $24.0 million.

Q. Please describe how hydro conditions and the decommissioned Klamath river hydro generating plants have impacted NPC.

A. Weather conditions throughout 2024 have continued to lead to lower water volumes for the Company's hydro resources which reduced the availability of the Company's hydro resources. Additionally, the Company decommissioned all of its hydro generating facilities on the Klamath river consisting of the Copco #1, Copco #2, Iron Gate, and JC Boyle generating plants. In 2024, actual generation from the Company's hydro resources was 1,038 GWh (29 percent) lower than forecasted generation from Base NPC as shown in Table 7 below and needed to be replaced to meet customer demand, which had an estimated impact on total-Company NPC of $61 million. The Company has also updated its forecast for hydro generation volumes in its pending general rate case to better reflect actual operating conditions and the decommissioning of the Klamath river hydro generating facilities.

Table 7
Hydro Generation

Year	Base GWh	Actual GWh	Variance	Percent
2021 EBA	3,627	2,789	(838)	(23%)
2022 EBA	3,627	2,936	(691)	(19%)
2023 EBA	3,627	3,000	(627)	(17%)
2024 EBA	3,627	2,589	(1,038)	(29%)

Q. Please describe how the January 2024 North America winter storm over the Martin Luther King Jr. holiday weekend impacted NPC.

A. Between January 13, 2024 and January 16, 2024, North America experienced a significant winter storm with wide-ranging impacts increasing both market and natural gas prices, along with increasing demand. Table 8 and Table 9 below show the large variance between average January market power and gas prices against the average February through December market and gas prices at the Opal and Sumas natural gas hubs and Mid-Columbia and Four Corners market purchase power hubs for 2024. The total cost of day-ahead and real-time market purchases during this storm was $89.9 million.

Table 8
Opal and Sumas Average Monthly Price ($/MMBtu)

Month	Opal	Sumas
Jan	$6.39	$6.33
Feb - Dec	$1.82	$1.61

Table 9
Mid-Columbia and Four Corners Average Monthly Price ($/MWh)

Month	Mid-C HLH	Four-C HLH
Jan	$249.95	$91.38
Feb - Dec	$46.50	$43.91

VII. ADJUSTMENTS RELATED TO FINAL EBA RATES

Q. Please explain the adjustment to reflect the 2024 EBA Order.

A. The 2024 EBA Order adopted two adjustments to the recovery requested in that docket with respect to Schedule 137 prior period adjustments and Washington Climate Commitment Act/Greenhouse Gas expenses. The impact to this EBA is a reduction to the requested recovery by $24,244,080, including interest.

Q. Please explain the adjustment related to the 2023 EBA.

A. After collection of the authorized EBA in Docket No. 23-035-01 through Schedule 94 concluded, $238,367 still remained to be collected from customers. The Company has included this remaining balance to be recovered in this EBA.

VIII. IMPACT OF PARTICIPATING IN THE WEIM

Q. What is the CAISO Western Energy Imbalance Market?

A. The CAISO WEIM is an advanced real-time energy market that automatically finds low-cost energy to serve real-time consumer demand across the west by allowing participants to buy and sell power close to the time electricity is consumed. Since its launch in 2014, the WEIM has enhanced grid reliability, improved the integration of renewable resources, lowered carbon emissions, and generated significant cost savings for its participants.

Q. Are the actual benefits from participating in the WEIM included in the EBA deferral?

A. Yes. Participation in the WEIM provides significant benefits to customers in the form of reduced Actual NPC. The benefits are embedded in Actual NPC through lower fuel costs, lower purchased power costs, and higher wholesale sales revenue.

Q. What are the actual WEIM benefits included in the EBA deferral?

A. CAISO's WEIM benefits report indicates that PacifiCorp has received $192 million in benefits in 2024. Since inception of the WEIM, PacifiCorp has received $938 million in total benefits.

IX. CONCLUSION

Q. Please summarize your testimony.

A. The EBA deferral of $471.6 million, including interest for the calendar year 2024 Deferral Period, was accurately calculated in compliance with the EBA tariff and previous Commission orders.

Q. Does this conclude your direct testimony?

A. Yes.

Rocky Mountain Power
Exhibit RMP___(JP-1)
Docket No. 25-035-01
Witness: Jack Painter

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Jack Painter

Monthly EBA Deferral Calculation

May 2025

Utah Energy Balancing Account Mechanism
January 1, 2024 - December 31, 2024
Exhibit 1 - Commission Order Calculation Method (Dynamic Annual Allocation Factor

Line No.		Reference	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	Total
	Actual: Utah Allocated														
1	NPC	(2.1)	$ 149,206,779	$ 86,696,460	$ 77,870,597	$ 70,805,457	$ 73,192,717	$ 89,664,249	$ 142,886,704	$ 128,489,642	$ 113,846,927	$ 76,449,967	$ 81,485,862	$ 84,718,164	$ 1,175,313,526
2	PTC	(9.1)	(10,513,106)	(10,643,549)	(10,794,710)	(11,028,473)	(11,277,459)	(10,819,453)	(6,235,742)	(7,600,984)	(6,742,853)	(8,076,453)	(11,072,928)	(15,532,071)	(120,337,780)
3	Wheeling Revenue	(4.1)	(7,388,048)	(6,515,681)	(7,071,318)	(6,454,661)	(5,895,390)	(8,816,253)	(9,751,938)	(9,361,347)	(8,175,534)	(7,443,032)	(7,029,934)	(5,122,293)	(89,025,428)
4	Total	∑ Lines 1:3	$ 131,305,625	$ 69,537,230	$ 60,004,569	$ 53,322,324	$ 56,019,868	$ 70,028,543	$ 126,899,024	$ 111,527,310	$ 98,928,540	$ 60,930,483	$ 63,383,000	$ 64,063,800	$ 965,950,318
5	Jurisdictional Sales	(5.2)	2,214,801	1,998,881	1,996,692	1,780,136	1,956,804	2,456,624	2,656,486	2,605,963	2,016,042	2,109,248	2,078,134	2,200,823	26,070,633
6	Actual Utah $/MWh	Line 4 / Line 5	**$ 59.29**	**$ 34.79**	**$ 30.05**	**$ 29.95**	**$ 28.63**	**$ 28.51**	**$ 47.77**	**$ 42.80**	**$ 49.07**	**$ 28.89**	**$ 30.50**	**$ 29.11**	**$ 37.05**
	Base: Utah Allocated														
7	NPC	(3.1)	$ 52,896,516	$ 49,963,481	$ 51,232,250	$ 45,143,308	$ 46,529,610	$ 53,485,781	$ 61,875,110	$ 58,318,910	$ 49,315,103	$ 48,730,667	$ 51,240,255	$ 55,415,210	$ 624,146,199
8	PTC	(9.1)	(8,852,301)	(8,852,301)	(8,852,301)	(8,852,301)	(8,852,301)	(8,852,301)	(8,852,301)	(8,852,301)	(8,852,301)	(8,852,301)	(8,852,301)	(8,852,301)	(106,227,616)
9	Wheeling Revenue	(4.1)	(4,219,347)	(4,219,347)	(4,219,347)	(4,219,347)	(4,219,347)	(4,219,347)	(4,219,347)	(4,219,347)	(4,219,347)	(4,219,347)	(4,219,347)	(4,219,347)	(50,632,163)
10	Total	∑ Lines 7:9	$ 39,824,867	$ 36,891,833	$ 38,160,602	$ 32,071,659	$ 33,457,962	$ 40,414,132	$ 48,803,462	$ 45,247,261	$ 36,243,454	$ 35,659,019	$ 38,168,606	$ 42,343,562	$ 467,286,420
11	Jurisdictional Sales	(5.2)	2,087,756	1,833,770	1,924,709	1,851,240	1,929,518	2,156,059	2,546,774	2,449,322	2,055,691	1,956,778	1,940,943	2,104,828	24,837,388
12	Base Utah $/MWh	Line 10 / Line 11	**$ 19.08**	**$ 20.12**	**$ 19.83**	**$ 17.32**	**$ 17.34**	**$ 18.74**	**$ 19.16**	**$ 18.47**	**$ 17.63**	**$ 18.22**	**$ 19.66**	**$ 20.12**	**$ 18.81**
	Deferral:														
13	$/MWH Differential	Line 6 - Line 12	$ 40.21	$ 14.67	$ 10.23	$ 12.63	$ 11.29	$ 9.76	$ 28.61	$ 24.32	$ 31.44	$ 10.66	$ 10.83	$ 8.99	$ 18.24
14	EBA Deferrable	Line 5 * Line 13	**$ 89,057,317**	**$ 29,323,691**	**$ 20,416,779**	**$ 22,482,509**	**$ 22,088,775**	**$ 23,980,484**	**$ 75,993,160**	**$ 63,386,373**	**$ 63,384,137**	**$ 22,492,943**	**$ 22,516,535**	**$ 19,789,069**	**$ 474,911,772**
15	Special Contract Customer Adjustment Subject to Deadband	(7.1)	(14,968,940)	(1,441,943)	(661,871)	(461,336)	(306,932)	(324,133)	(1,209,043)	(1,242,037)	(1,580,884)	(1,369,650)	(665,971)	(1,021,212)	(25,253,951)
16	Symmetrical Deadband	Docket 16-035-33	350,000	350,000	350,000	350,000	350,000	350,000	350,000	350,000	350,000	350,000	350,000	350,000	350,000
17	Total Special Contract Adjustment	Line 15 - Line 16	(14,618,940)	(1,441,943)	(661,871)	(461,336)	(306,932)	(324,133)	(1,209,043)	(1,242,037)	(1,580,884)	(1,369,650)	(665,971)	(1,021,212)	(24,903,951)
18	Utah Situs Resource Adjustment	(8.1)	(140,585)	480,457	690,871	1,804,880	1,184,397	1,188,862	(100,006)	1,523,655	484,723	645,662	941,906	515,303	9,220,126
19	Total Incremental EBA Deferral	∑ Lines 14 and Lines 17:18	**$ 74,297,793**	**$ 28,362,206**	**$ 20,445,780**	**$ 23,826,053**	**$ 22,966,241**	**$ 24,845,213**	**$ 74,684,111**	**$ 63,667,991**	**$ 62,287,976**	**$ 21,768,955**	**$ 22,792,470**	**$ 19,283,160**	**$ 459,227,947**
	Energy Balancing Account:														
20	Monthly Interest Rate	Note 1	0.38%	0.38%	0.38%	0.45%	0.45%	0.45%	0.45%	0.45%	0.45%	0.45%	0.45%	0.45%	
21	Beginning Balance	Prior Month Line 28	$ -	$ 74,439,268	$ 103,138,970	$ 124,016,469	$ 148,447,408	$ 172,125,340	$ 197,787,538	$ 248,817,792	$ 313,730,430	$ 377,544,355	$ 401,032,710	$ 425,650,246	$ -
22	Incremental Deferral	Line 19	74,297,793	28,362,206	20,445,780	23,826,053	22,966,241	24,845,213	74,684,111	63,667,991	62,287,976	21,768,955	22,792,470	19,283,160	459,227,947
23	2023 PTC Update								(397,024)						(397,024)
24	EVIP Revenue	Docket 20-035-34						(4,244)	(4,244)	(4,244)	(8,723)	(9,088)	(10,219)	(10,291)	(51,052)
25	2023 EBA Collection True-Up	Docket 23-035-01												238,367	238,367
26	2024 EBA Final Order Adjustment	Docket 24-035-01							(24,244,080)						(24,244,080)
27	Interest	Line 20 * (Line 21 + 50% x Line 22)	141,475	337,496	431,720	604,886	711,691	821,229	991,491	1,248,891	1,534,672	1,728,488	1,835,286	1,937,556	12,324,881
28	**Ending Balance**	∑ Lines 21:27	**$ 74,439,268**	**$ 103,138,970**	**$ 124,016,469**	**$ 148,447,408**	**$ 172,125,340**	**$ 197,787,538**	**$ 248,817,792**	**$ 313,730,430**	**$ 377,544,355**	**$ 401,032,710**	**$ 425,650,246**	**$ 447,099,038**	**$ 447,099,038**
29	Interest Accrued January 1, 2025 through March 31, 2025	Line 28 * (1 + 1.0534% / 12) ^ 3 - Line 28													5,995,373
30	Interest Accrued April 1, 2025 through June 30, 2025	Line 28 and 29 * (1 + 1.0540% / 12) ^ 3 - Line 28 and 29													6,144,341
31	Interest Accrued through Rate Effective Period July 1, 2025 through June 30, 2026														12,376,556
32	**Requested EBA Recovery**	∑ Lines 28:30													**$ 471,615,308**

Notes:

1 Interest rate is from Electric Service Schedule No. 300 due to Docket No. 09-035-15/Order Issued November 14, 2019.