Rocky Mountain Power
Docket No. 22-035-01
Witness: Jack Painter

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Direct Testimony of Jack Painter

March 2022

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 Specialist.

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 specialist in 2020.

Q. Have you testified in previous regulatory proceedings?

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

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, 2021 through December 31, 2021 ("Deferral Period"). More specifically, I provide the following:

- Details supporting the calculation of the Company's request to recover $90.6 million for excess EBA-related costs, including interest, an adjustment for sales made to a special contract customer, and Utah situs resource adjustments included in the EBA for the true-up of solar facilities and the Utah Transition Program for Customer Generators;

- 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 energy imbalance market ("EIM") with California Independent System Operator ("CAISO") and the benefits from EIM that are passed through to customers.

Q. Is an additional witness presenting testimony specifically for the EBA and Electric Service Schedule No. 94 ("Schedule 94") in this case?

A. Yes. Mr. Robert M. Meredith, Director, Pricing & Tariff Policy, provides testimony on the proposed Schedule 94 rates.

SUMMARY OF THE EBA DEFERRAL CALCULATION

Q. Please summarize the Company's EBA application.

A. The Company's application requests recovery of $90.6 million in deferred costs, comprised of $107.6 million of EBA-related costs, a credit of $22.4 million for sales made to a special contract customer, a $2.9 million adjustment for Utah situs resources, and approximately $2.6 million of interest.

Q. Are there any changes to the EBA calculation?

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

- Base NPC rates have been updated to reflect the Company's most recent 2020 general rate case ("GRC") filing in Docket No. 20-035-04.
- Production Tax Credits ("PTC") are included in the EBA calculation as part of the Company's 2020 GRC filing in Docket No. 20-035-04.

- The interest calculation for the period after the deferral has been updated to reflect the Company's recent proposal to implement interim rates, which is pending Commission approval in Docket No. 22-035-T05.[1]

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 2021 EBA Deferral			*Exhibit RMP___(JP-1) Reference*
Actual EBA ($/MWh)	$	23.04	*Line 6*
Base EBA ($/MWh)		18.81	*Line 12*
$/MWh Differential	**$**	**4.22**	
Utah Sales (MWh)		25,523,328	*Line 5*
EBA Deferrable*	$	107,599,353	*Line 14*
Special Contract Customer Adjustment*		(22,400,376)	*Line 17*
Utah Situs Resource Adjustment*		2,866,745	*Line 18*
Total Deferrable	$	88,065,722	*Line 19*
Interest Accrued through December 31, 2021		1,451,080	*Line 23*
Interest Accrued January 1, 2022 through March 31, 2022		871,124	*Line 25*
Interest Accrued April 1, 2022 through April 30, 2022		229,736	*Line 26*
Requested EBA Recovery	**$**	**90,617,662**	*Line 27*

** Calculated monthly*

The EBA deferral of $107.6 million is calculated as the difference between the Actual NPC, PTC's and wheeling revenue and the Base NPC, PTC's and wheeling revenue,

[1] PacifiCorp's tariff filing was filed March 2, 2022 in Docket Nos. 22-035-T05 and 09-035-15 to implement interim rates in Schedule 94 on May 1, 2022.

as established in the 2020 GRC. The calculation of the monthly amount debited or credited into the EBA Deferral Account is based on the following formula:

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

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

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

A. The EBA deferral calculation consists of three revenue requirement components: NPC, PTC's and wheeling revenue. NPC are defined as the sum of fuel expenses, wholesale purchase power expenses, and wheeling expenses, less wholesale sales revenue. PTC's 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 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 $1.694 billion. This amount captures all components of NPC as defined in the Company's GRC proceedings and modeled by the Company's Generation and Regulation Initiative Decision Tool ("GRID") 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. 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;
- Situs assignment of the generation from Oregon solar resources procured to satisfy Oregon Revised Statute 757.370 solar capacity standard;
- Situs assignment of Oregon allocated excess amortization related to a prepaid wheeling expense;
- Situs assignment of certain Utah resources;
- Situs assignment of Reasonable Energy Price adjustments to QF's
- Coal inventory adjustments to reflect coal costs in the correct period;
- Legal fees related to fines and citations included in the cost of coal;
- Adjustments related to liquidated damages that occurred outside the Deferral Period—all liquidated damage fees per a coal supply agreement are booked in accordance with generally accepted accounting principles ("GAAP");
- Electric Service Schedule No. 32 ("Schedule 32") and Schedule 34 ("Schedule 34") contracts; and
- An adjustment for costs related to participation in the Western Power Pool's ("WPP") Western Resource Adequacy Program ("WRAP").
- Situs assignment of the EIM Body of State Regulators ("BOSR") fees charged for commission related work as a participant in the EIM.

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 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 interest 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. Additionally, the calculation of carrying charges has been updated to reflect interim rates and a 14-month amortization period as requested in Docket No. 20-035-T05 by reducing the time frame from the end of the deferral period until collection of the deferral begins to 4 months as described in the Application.

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 2022 EBA, the adjustment for sales made to a special contract customer is a $22.4 million credit.

Q. Please describe the Utah Situs Resource Adjustment.

A. The Utah Situs Resource Adjustment accounts for the Utah situs costs of certain resources and expenses, namely the Utah Subscriber Solar Program, the Utah Transition Program for Customer Generators, and the EIM BOSR fees charged for commission related work as a participant in the EIM.

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 EBA adjustment rate schedule changes (Schedule 73, Special Condition 15).

Q. Please describe the 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.[2] The generation costs of the solar resource are compared to the generation charges paid by solar subscriber customers and 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 approximately $48 thousand.

Q. Please describe the Utah Transition Program for Customer Generators ("Transition Program").

A. In Docket No. 14-035-114, the Commission approved the Transition Program Electric Service Schedule No. 136, effective November 15, 2017, which measures the difference between the electricity supplied by the Company and the electricity generated by an eligible customer-generator and fed back to the electric grid at 15-minute intervals. The program enables eligible customers to offset part or all of their own electrical requirements with self-generation and receive export credits for energy

[2] Order approving amended settlement agreement, Docket No. 15-035-61, issued October 21, 2015, Page 7 of the amended settlement stipulation.

fed back to the electric grid.

Q. Please describe the adjustment to the EBA for the Transition Program.

A. Under the stipulation in Docket No. 14-035-114, the difference between export credits to eligible customers and the market value of the exports is recovered from or credited back to Utah customers through the EBA. The EBA adjustment for the Transition Program is approximately $2.8 million.

Q. Please explain the purpose of the EIM BOSR.

A. The EIM BOSR is a body that addresses the regional nature of the EIM through the EIM governance process. The purpose of the EIM BOSR is to provide "a forum for state commissioners to (1) select a voting member of the EIM Governing Body Nominating Committee, (2) learn about and discuss the EIM and CAISO markets, and (3) express a common position in CAISO stakeholder processes or the EIM Governing Body on EIM issues."[3]

Q. Please describe new fee that is associated with the EIM BOSR.

A. As described by the EIM BOSR, the fee supports the BOSR's expenses and support 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."[4]

Q. Please describe the adjustment to the EBA for the EIM BOSR Fees.

A. The Utah allocated cost in the EBA is $44,639.

[3] *EIM BOSR Energy Imbalance Market Body of State Regulators*, WESTERN INTERSTATE ENERGY BOARD ofpc2022), https://www.westernenergyboard.org/energy-imbalance-market-body-of-state-regulators/.
[4] ibid.

Q. What is the WPP WRAP?

A. The WPP WRAP is the new 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.

Q. Please explain the WPP WRAP Fee.

A. There are three main components of the WRAP fee that are necessary to meet the Company's resource adequacy requirements for the WPP WRAP. First is facilitation and coordination services, include the use of staff resources related to facilitation and coordination services provided by WPP Corporation in connection with the Phase 3A Scope of Work. Secondly, WPP will bill to the participants the expenses the WPP Corporation incurs directly to perform the Phase 3A Scope of Work, including costs associated with contracting for a Program Operator. Finally, there are binding program preparation costs including preparation for Federal Energy Regulatory Commission filings, setting up an independent board and preparing the WPP Corporation to undertake the obligations required to house the program as a public utility under the Federal Power Act.

Q. Please describe the adjustment to the EBA for the WPP WRAP Fees.

A. The total-Company cost for 2021 is $129,720 and the Utah allocated cost in the EBA is $57,825.

Q. Please describe the adjustment to the EBA for the Schedule 32 and 34 Contracts.

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 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.

DIFFERENCES IN NPC

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 were $1.694 billion, approximately $263 million more than Base NPC for the Deferral Period. Table 2 below provides a high-level summary of the difference between Base NPC and Actual NPC by category on a total-Company basis.

Table 2
Net Power Cost Reconciliation ($ millions)

	TOTAL
Base NPC	**$ 1,431**
Increase/(Decrease) to NPC:	
Wholesale Sales Revenue	42
Purchased Power Expense	125
Coal Fuel Expense	30
Natural Gas Expense	52
Wheeling and Other Expense	13
Total Increase/(Decrease)	**263**
Total Company NPC Difference	**$ 263**
Adjusted Actual NPC	**$ 1,694**

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

A. The Base NPC for the 2022 EBA was 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 at $1.431 billion.

Q. Please describe some of the weather events that impacted NPC.

A. 2021 was characterized by a large number of extreme and unforeseeable weather events. Collectively, they shaped actual NPC throughout the year. For instance, February 2021 saw a polar vortex that brought record cold temperatures to a significant portion of the United States from February 6, 2021 through February 22, 2021 with temperatures falling as much as 25-50 degrees Fahrenheit below average. Combining this event with the 2021 Texas power crisis created a perfect storm and market prices were significantly higher during this period.

After the polar vortex, the Company experienced another significant impact to NPC with the Western North America heat wave, a 13 day long extreme weather event that occurred between June 25, 2021 and July 7, 2021 that saw a temperature peak of 119 degrees Fahrenheit in the Western United States and had a significant impact on market prices for June and July as compared to the same period in 2020.

Q. Please describe how drought conditions have an effect on NPC.

A. Ongoing drought has caused negative effects to NPC because it impacts the availability of hydro resources. In 2021, actual generation from hydro resources were 837,340 MWhs, or 23 percent lower, than forecasted generation. Unrealized hydro MWhs need to be replaced to meet customer demand through system dispatch of other resources, reducing market sales, increasing market purchases or any combination of these options. The estimated impact to total-Company NPC of the decreased hydro MWhs due to drought is $39.3 million.

Q. Please describe the primary differences between Actual NPC and Base NPC.

A. As shown in Table 2, Actual NPC were higher than Base NPC due to a $42 million reduction in wholesale sales, a $125 million increase in purchased power expense, a $52 million increase in natural gas expense, a $30 million increase in coal fuel expense, and a $13 million increase in wheeling and other expenses.

Q. Please explain the changes in wholesale sales revenue.

A. The decline in wholesale sales revenues relative to Base NPC was due to a reduction in the wholesale sales volumes of market transactions (represented in GRID as short-term firm and system balancing sales).

Revenue from market transactions is approximately $42 million lower than Base NPC due to a lower volume of market sales transactions, but offset by increased market prices. The average price of actual market sales transactions was $5.82/MWh, or 18 percent, higher than the average price in Base NPC. Actual wholesale market volumes were 2,203 gigawatt-hours ("GWh"), or 31 percent, lower than the Base NPC.

Q. Please explain the changes in purchased power expense.

A. The increase in purchased power expense relative to Base NPC was due to an increase in the average price of market purchase transactions (represented in GRID as short-term firm and system balancing purchases) with a significant impact tied to the polar vortex in February, the Western North America heat wave in June and July, and drought.

Expenses from market transactions increased by $303.6 million compared to Base NPC. Actual market purchases were 860 GWh (24 percent) higher than Base NPC and the average price of actual market purchases transactions was $65.47/MWh (381 percent) higher than Base NPC.

For the polar vortex in February, the Mid-Columbia market hub saw average market prices increase 188 percent for peak hours and 151 percent for off-peak hours while the Four Corners market hub saw average market prices increase 520 percent for peak hours and 242 percent for off-peak hours.

With the heat wave in June and July, the Mid-Columbia market hub saw an average increase in high load hour market prices of 620 percent and 560 percent respectively while the Four Corners market hub saw an average increase in high load hour market prices of 464 percent and 150 percent, respectively. Combining the impact of increased actual Utah sales in June and July over base sales and higher market prices results in a NPC variance of $78.4 million above base NPC on a Utah-allocated basis.

Q. Please explain the changes in wheeling expenses.

A. The increase in wheeling expenses relative to Base NPC was primarily due to an increase in short-term firm wheeling expense of $11.8 million.

Q. Please discuss the changes in coal fuel expense.

A. The principal driver of the coal fuel expense increase is a coal generation volume increase of 3,496 GWh (12 percent) compared to Base NPC. The average cost of coal generation decreased slightly from $21.45/MWh in Base NPC to $20.03/MWh in the Deferral Period, but the higher generation results in an overall increase of approximately $30 million in coal fuel expense.

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

A. The total natural gas fuel expense in Actual NPC increased by $52 million compared to Base NPC. The main driver of the increase is the average cost of natural gas generation increased from $20.73/MWh in Base NPC to $26.40/MWh (27 percent) in the Deferral Period, but increased costs were offset by a decrease in natural gas generation volume of 1,116 GWh (8 percent) below Base NPC during the Deferral Period.

Natural gas market prices were also impacted by the extreme weather events in 2021. At the Opal natural gas trading hub, average market prices were 790 percent higher in February 2021 as compared to the same period last year and June and July 2021 were 115 percent and 135 percent higher respectively. Overall, gas prices at Opal were 137 percent higher in 2021 as compared to 2020.

IMPACT OF PARTICIPATING IN THE EIM

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

A. Yes. Participation in the EIM provides benefits to customers in the form of reduced Actual NPC. The EIM benefits are embedded in Actual NPC through lower fuel and purchased power costs. For 2021, CAISO's EIM benefits report shows $115.5 million in EIM benefits for PacifiCorp and $391.4 million since the inception of the EIM.

Q. Does this conclude your direct testimony?

A. Yes.