Rocky Mountain Power
Docket No. 25-035-06
Witness: Daniel J. MacNeil

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Direct Testimony of Daniel J. MacNeil

June 2025

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

A. My name is Daniel J. MacNeil. My business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My present position is Commercial Analytics Adviser.

I. QUALIFICATIONS

Q. Briefly describe your education and professional experience.

A. I received a Master of Arts degree in International Science and Technology Policy from George Washington University and a Bachelor of Science degree in Materials Science and Engineering from Johns Hopkins University. Before joining PacifiCorp ("Rocky Mountain Power" or "Company"), I completed internships with the U.S. Department of Energy's Office of Policy and International Affairs and the World Resources Institute's Green Power Market Development Group. I have been employed by PacifiCorp since 2008, first as a member of the net power costs group, then as manager of that group from June 2015 until September 2016. In my current role, I provide analytical expertise on a broad range of topics related to PacifiCorp's resource portfolio and obligations, including oversight of the calculation of avoided cost pricing in PacifiCorp's jurisdictions.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have provided testimony in California, Idaho, Oregon, Utah, Washington, Wyoming, and Federal Energy Regulatory Commission ("FERC") dockets.

II. PURPOSE OF TESTIMONY AND RECOMMENDATION

Q. What is the purpose of your testimony?

A. My testimony describes the Company's proposed methodology for valuing clean energy resources proposed by the Utah Community Clean Energy Program ("Program") and identifying the associated incremental cost to be recovered from participating customers under the proposed Electric Service Schedule No. 100 ("Schedule 100").

Q. Please summarize your recommendations for the Commission.

A. For each proposed Schedule 100 resource the Company will provide an estimate of the value using the methodology established for Electric Service Schedule No. 38 ("Schedule 38"), adjusted for the impact of transmission upgrade costs associated with the proposed Schedule 100 resource and the impact of the contract term beyond the production cost model study horizon. This value will be non-confidential.

The Company will also provide an adjusted valuation that incorporates Renewable Energy Credit ("REC") value and any price-policy, risk, or other modifications it believes are appropriate to ensure the Schedule 100 resource value does not shift any costs or benefits to non-participating customers. Certain discussion and detail related to these cost elements will be confidential, to protect the Company's ability to negotiate the best contracts for resources and RECs on behalf of all customers.

III. VALUATION METHODOLOGY

Q. What is the basis for the Schedule 100 resource valuation methodology?

A. The Company is basing its Schedule 100 resource valuation methodology by adhering to the Utah Community Clean Energy Act[1], specifically UT Code § 54-17-904(4), which considers the bases for Commission-approval of rates for participating customers; and Utah Admin. Code § 54-17-904(2)(d), which considers necessary aspects taken into account when the Company forms proposed rates to be approved by the Commission.

Q. Which costs and benefits in the statute are addressed by your testimony?

A. My testimony addresses UT Code § 54-17-904 (2)(d)(ii), namely "…*quantifiable costs and benefits to the qualified utility and all of the qualified utility's customers."* Each incremental resource added to the Company's portfolio provides energy and capacity benefits. A variety of factors should be considered when establishing the incremental costs of a proposed Schedule 100 resource that need to be collected from participating customers, relative to its quantifiable benefits, so as to ensure compliance with this statute.

Q. Will the benefits of new clean energy resources be determined in the same manner as the avoided costs calculated under the Commission-approved applicable to non-standard Qualified Facilities ("QFs") in accordance with Schedule 38?

A. Not necessarily. As a starting point, the Company proposes to include a calculation that reflects the current Schedule 38 methodology; however, the Company performs more analysis when it is considering procurement of significant non-QF resources. The incremental analysis can include:

- Multiple price-policy scenarios;
- Stochastic risk assessment;

[1] Previously known as the "Utah Community Renewable Act"; *See generally*, Utah Admin Code § 54-17-901.

- Variant analysis (alternative resources and/or transmission);
- Sensitivity analysis (other input assumption alternatives); or
- Resource cost validation.

I will address modifications to the Schedule 38 methodology as well as each of these incremental analysis items in the sections below.

IV. MODIFICATIONS TO THE SCHEDULE 38 METHODOLOGY

Q. Does the Schedule 38 methodology have any specific limitations relative to Schedule 100 resource valuation?

A. Yes. There are four primary elements of the Schedule 38 methodology that require modifications with respect to Schedule 100 resource valuation: interconnection costs, transmission service costs, REC valuation, and valuation estimates for the life of the contract beyond the production cost model study horizon.

Q. Please describe the Schedule 100 resource valuation issue related to interconnection costs.

A. When a Utah QF seeks to interconnect to the transmission system, studies performed by PacifiCorp Transmission identify any upgrades that are necessary and the cost of those upgrades are paid for by the QF, according to regulations established by the Commission. In contrast, when PacifiCorp Transmission's interconnection study for a non-QF resource identifies transmission system upgrades that are needed to accommodate the additional resource, the cost of the upgrades is initially funded by the developer of the resource but refunded over time, with interest. Thus, for non-QF resources, the cost of transmission system upgrades generally becomes part of the transmission system rate base, paid for by all transmission customers, under regulations established by FERC. This cost is incremental to the compensation paid to the developer in a power purchase agreement and is not captured in Schedule 38, where it is not applicable, so it must be accounted for to ensure costs are not shifted to non-participating customers.

Q. Please describe the Schedule 100 resource valuation issue related to transmission service costs.

A. After the contract for a Schedule 100 resource is executed, the Company submits a request to PacifiCorp Transmission to designate it as a network resource. If necessary, PacifiCorp Transmission may need to study whether sufficient transmission capacity is available to deliver the resource to the Company's retail load. If insufficient transmission capacity is available, PacifiCorp Transmission will identify the costs and timing of required upgrades. This request cannot be made until after contract execution and the Company's proforma power purchase agreements allow for termination if upgrades are required and costs exceed a specified threshold, typically one million dollars for utility-scale resources.

Q. How does the Company account for the costs of transmission upgrades when evaluating non-QF resources?

A. The costs of transmission upgrades are identified in interconnection studies completed by PacifiCorp Transmission. Similarly, while the cost of network resource designation may not be known until well after contract execution, it is appropriate to account for potential costs up to the designated network resource cost threshold. When evaluating bids received in a request for proposals ("RFP") or in bilateral negotiations, the analysis accounts for transmission costs by converting them into a real-levelized annualized cost. This technique is also appropriate as part of the evaluation of a Schedule 100 resource, and uses the following inputs:

a) Network upgrade transmission cost ($): The cost of modifications or additions to transmission-related facilities that are integrated with and support the overall transmission system for the general benefit of all users.

b) Open Access Transmission Tariff Share (%): the percentage of the Company's transmission service attributable to retail customers. The remaining portion of the cost of network transmission upgrades are recovered from wholesale transmission customers.

c) Real-levelized Payment Factor (%): This percentage reflects the revenue requirement associated with transmission plant, levelized over its life in constant real dollars (i.e. grow at inflation in nominal dollars).

The total annual cost of a transmission upgrade for the Company's retail customers is thus:

[(a) * (b)] * (c) * (1 + Inflation) ^ (Current year – 1st year of operation)

Q. Would Utah retail customers pay the entire cost of all transmission upgrades associated with Schedule 100 resources?

A. Not at present. Currently, the Company's six state jurisdictions make up approximately eighty percent of the total transmission service provided by PacifiCorp Transmission, with third-party transmission customers representing the other twenty percent. PacifiCorp Transmission's Open Access Transmission Tariff ("OATT") rates are based on a formula which allocates the entire cost of the transmission system to all transmission customers, resulting in a portion of each transmission upgrade cost being paid for by third-party transmission customers as shown in the equation above.

The Company's retail customers are also allocated a portion of the transmission upgrade costs necessary to serve third-party transmission customers. While this current system has been in place for many years, recent FERC orders require long-term planning for regional transmission facilities, to identify future needs and how costs should be allocated.[2] As a result, it is possible that transmission cost allocation could change in the future, at least for certain upgrades.

Q. Please describe the Schedule 100 resource valuation issue related to RECs.

A. Under the Schedule 38 methodology, the Company retains RECs during any period in which a QF's pricing reflects deferral of a renewable resource. This maintains a balanced outcome, as the RECs that would have been generated by a renewable resource are replaced by RECs generated by the QF. However, this methodology does not place a specific value on RECs.

Q. Does the Company's long-term planning identify a specific value for RECs acquired from resources used to serve Utah customers?

A. No. While other states include compliance requirements related to RECs, the Company's Integrated Resource Plan ("IRP") does not assign a value to RECs produced for Utah customers.

Q. Will the Schedule 100 resource valuation need to account for the lost value of RECs?

A. Yes. Utah customers benefit from the RECs generated by the resources included in

[2] Federal Energy Regulatory Commission (FERC), Order No. 1920, 85 FERC ¶ 61,205, (May 13, 2024); FERC Order 1920-A, (Nov. 21, 2024).

their rates. The value of RECs is uncertain but varies by resource type and vintage and should be accounted for in the Schedule 100 resource valuation.

Q. Is there a second incremental cost impact related to RECs?

A. Yes. Both owned resources and non-QF purchases can be curtailed in the Western Energy Imbalance Market ("WEIM"). When curtailment occurs, the Company's power purchase contracts include compensation at the contract price for the generation which would otherwise have occurred, plus the value of any lost production tax credits on the curtailed output. When curtailment occurs, RECs are not generated, and a Schedule 100 incremental cost tied to the REC volume would result in lower compensation. The portion of the contract price recovered from Schedule 100 customers would not be collected in that interval, even though the project owner is still receiving the full contract price for the potential output. To make up for this difference, a resource with a contracted REC would not be curtailed until the negative market price exceeds the cost of the REC.

Q. Do WEIM prices frequently become negative?

A. Yes. In the WEIM data for PacifiCorp's east balancing authority area for the twelve months ending June 2024, a total of over 460 hours had negative prices, more than 5% of the total hours in a calendar year.[3] During those negatively priced periods, the average market price was approximately -$15 per megawatt-hour, which would be an appreciable contributor to the overall value of the resource. While five percent sounds like a small amount, the occurrences are not random, and most of those negative prices

[3] *Rocky Mountain Power's Notice of Intent to Use Export Credit Rate Input*, Docket No. 24-035-57, Tariff, RMP Workpaper A – UT Schedule 136 Export Credit Annual Update (Jan. 27, 2025).

occur in the middle of the day, when solar generation is high. The relative impacts are even higher when considering that a typical solar facility operates at a capacity factor of approximately 28% meaning the 5% of hours with negative pricing could correspond to nearly 18% of the expected output of a solar facility. The frequency is expected to increase as more variable energy resources like wind and solar are added to the regional transmission grid, driven by the value of production tax credits, RECs and renewable portfolio standards in the region.

Q. Can the Company's production cost modeling account for this effect?

A. To a degree. The Company's modeling reflects the marginal costs of the Company's resource portfolio and transmission rights, with limited connections to broader markets at static prices. In actual operations, WEIM prices are not static and reflect the marginal cost of supply relative to regional demand. The Company can model the REC value associated with a particular resource and curtail higher cost resources first (i.e., less negative costs).

A resource with a $10 per megawatt-hour REC would be curtailed only when marginal prices drop below -$10 per megawatt-hour, resulting in generation (and incremental costs) whenever marginal costs are between -$10 and $0. There are two issues with this. First, the incremental cost (i.e. REC value) for Schedule 100 resources is not determined until after production cost modeling is complete, while the REC price is also an input, so adjustments may be necessary based on the final result. Second, as previously discussed, much like the value of RECs, the prevalence and magnitude of negative market prices is highly uncertain. This is an important risk factor for variable energy resource procurement, particularly solar, which is naturally highly correlated with the solar resources across the region and should be, at a minimum, qualitatively part of the Commission's determination of Schedule 100 resource value.

Q. Please describe the Schedule 100 resource valuation issue related to the life of the contract beyond the production cost model study horizon.

A. Under Schedule 38, there is a very limited chance of QF contract terms extending beyond the production model study horizon because QF contracts are limited to a term of fifteen years, the QF developer must select a commercial operation date within thirty months of contract execution, and the QF developer is subject to updated contract pricing if their contract negotiations are not complete within specified timelines. For Schedule 38, a simple extrapolation of the final year values at inflation is used in the rare event the study horizon ends before the QF contract term.

Schedule 100 resources are not limited by these factors and are likely to extend several years beyond the study horizon. To the extent a sizeable portion of the contract term is outside of the study horizon, an accurate determination of the incremental costs over that period is crucial, and a simple extrapolation may not suffice. In past resource procurement, the Company has extrapolated expected benefits over multiple years, and has worked around other known drivers, such as expiring production tax credit value, which may exist near the end of the study horizon but are not associated with the extended horizon. In the 2025 IRP, these "end effects" impacts related to the study horizon were explicitly reported as part of the preferred portfolio selection process and similar adjustments may be needed to appropriately compare cases with and without proposed Schedule 100 resources.[4]

V. PRICE-POLICY SCENARIOS

Q. What are price-policy scenarios?

A. Price-policy scenarios refer to the natural gas price and federal carbon dioxide policy assumptions used in the development of a portfolio and in calculating the dispatch costs of a portfolio. The Company's 2025 IRP evaluates three natural gas price conditions (low, medium, and high) and three federal carbon dioxide ("CO2") policy scenarios (zero compliance requirements, a high price on CO2 emissions, and compliance with current Environmental Protection Agency ("EPA") CO2 regulations). An additional CO2 policy scenario was developed to evaluate performance assuming a price signal that aligns with the social cost of greenhouse gases ("SC-GHG"). Analysis within the 2025 IRP is based on a selected set of price and policy assumption combinations, specifically:

- MN: Medium natural gas/No federal CO2 regulations.
- MR: Medium natural gas/Current federal CO2 regulations under Section 111 of the Clean Air Act. This scenario requires coal-fired resources to convert to an alternative fuel by 2030, install carbon capture and sequestration equipment by 2032, or retire by 2032.
- LN: Low natural gas/No federal CO2 regulations.
- HH: High natural gas/High CO2 cost applied to all emitting generators (starting 2030) with no other federal CO2 regulations. This scenario also includes

[4] *PacifiCorp 2025 Integrated Resource Plan*, Docket No. 25-035-22, 2025 Integrated Resource Plan Volume I, Chapter 9, Table 9.34 at 260 (March 31, 2025).

increased coal costs, proportionate to the change in natural gas pricing relative to the medium case, to reflect volatility in coal supply and availability.

- SC: Medium natural gas/Social cost of greenhouse gases (starting immediately) from Washington docket U-190730 with no other federal CO2 regulations.

Q. Are all of the IRP price-policy scenarios equally likely to occur?

A. No. The Company does not assign probabilities to the price-policy scenarios. The MN scenario is the expected case and is currently used in the Company's Official Forward Price Curve ("OFPC"). The LN and HH cases represent potential high and low conditions that could exist. While lasting fundamental changes in natural gas prices and greenhouse policy do occur, the conditions in the LN and HH cases might not persist for more than a year or two before reverting to more normal conditions.

Q. Are all of the IRP price-policy scenarios pertinent to the Schedule 100 resource valuation methodology?

A. No. Some of the price-policy scenarios have limited relevance to customer rates in Utah or are associated with other assumption changes. For example, the SC scenario does not represent costs that would be included in rates in Utah because it incorporates expected societal impacts of greenhouse gases that are required for long-term resource analysis by the Company's Washington jurisdiction and is not expected to be part of the dispatch decision in actual operations. The MR scenario assumes that federal requirements that are currently being litigated will be upheld, and that all of the Company's coal-fired resources will need to convert to natural gas, install carbon capture and sequestration equipment, or retire. The market prices in the MR scenario are not significantly different from the MN scenario, and this scenario can only be used in combination with relevant portfolios that include both the necessary modifications to the Company's coal-fired resources as well as indirect impacts on other resource procurement decisions that would be cost-effective if such a policy shift occurred.[5]

Q. What price-policy scenario is used under the Schedule 38 methodology?

A. The Schedule 38 methodology uses the Company's most recent OFPC, which is produced on a quarterly basis, and reflects the Company's current expectation for natural gas prices and expected compliance requirements under existing federal policy. At present, the OFPC reflects MN price-policy assumptions.

Q. What price-policy scenarios do you anticipate providing for the Commission's consideration for Schedule 100 resource valuation?

A. The Company expects to provide results under the MN, LN, and HH price-policy scenarios. This is comparable to the analysis the Company has used to justify the prudence of recent non-QF resource procurement.

Q. Does the Company typically weight price-policy results to produce a single value?

A. No. Typical procurement decisions evaluate two scenarios (with/without a resource) and identify the relative benefits of one alternative over another under a range of conditions. A larger spread in benefits between the two scenarios makes the choice easier, and more likely to hold under a wider range of possible future conditions, but the dollar amount of the difference doesn't impact the fundamental yes/no choice.

[5] *PacifiCorp 2025 Integrated Resource Plan*, Docket No. 25-035-22, 2025 Integrated Resource Plan Volume I, Chapter 1, Table 1.2 at 10 (March 31, 2025).

Q. Should results under the MN, LN, and HH price-policy scenarios be given equal weighting?

A. No. The MN scenario is expected to represent the most accurate results and in general, the Company would not pursue resources that were not cost-effective under the MN scenario. As a result, the MN results should receive the highest weighting.

Q. Should results under the LN and HH price-policy scenarios be given equal weighting?

A. Not necessarily. Assuming any weight is given to these price-policy conditions at all, they may not be equally likely to occur. Inclusion of these results could also be limited to cases where time constraints limit the ability to complete stochastic analysis as described in the next section.

VI. STOCHASTIC RISK ASSESSMENT

Q. What is stochastic risk assessment?

A. The Company's IRP develops portfolios that are optimized under expected conditions. In reality, many inputs vary from expected levels from year to year, and it is not possible to know which years in the future will be above or below average. With that in mind, the Company's 2025 IRP includes additional analysis that uses historical patterns for the following key inputs to identify a range of likely system conditions:

- Load;
- Hydro generation;
- Thermal outages;
- Market prices; and
- Wind and solar generation.

Portfolios that perform well under a range of possible conditions are more likely to result in lower costs in the long term.

Q. How much additional analysis is involved in stochastic risk assessment?

A. The Company's 2025 IRP includes eighteen stochastic scenarios, representing conditions in each historical calendar data from 2006-2023. Given the large scope of the analysis, stochastic risk assessment in the 2025 IRP was only conducted under the MN price-policy scenario.

Q. Did the Company weigh the stochastic scenario results in the 2025 IRP?

A. Yes. Random draws are used to identify a historical year for each year of the IRP study horizon (2025-2045) and this is repeated to create fifty iterations representing different combinations of historical years. The risk-adjustment accounts for the average variable cost impacts across all fifty iterations plus an additional five percent of the 95th percentile result (representing variable costs that exceed 95 percent of all outcomes). This is intended to reduce the risk of extreme cost outcomes.

Q. Should Schedule 100 resource valuation reflect risk-adjusted values using the 2025 IRP methodology, based on the MN price-policy scenario?

A. Yes, if time allows.

VII. VARIANT AND SENSITIVITY ANALYSIS

Q. What is variant analysis?

A. In the Company's IRP, variant analysis (also called "alternative-path" analysis) assesses the changes that would occur if certain major resource or transmission elements became unavailable (if selected in a base portfolio) or were required (if not selected in the base portfolio). Variant analysis looks at key portfolio decisions to identify both the relative cost-effectiveness of different options and the indirect changes that would occur when a portfolio is reoptimized with those differences incorporated. For example, the 2025 IRP included variant studies that the removed carbon capture and sequestration options and nuclear resource options, both of which were part of the preferred portfolio, plus studies which forced in offshore wind and geothermal, which were not part of the preferred portfolio. Besides the resource and transmission changes that are modified, the underlying assumptions in a variant case are unchanged.

Q. What is sensitivity analysis?

A. In the Company's IRP, sensitivity analysis assesses the changes that would occur with different modeling inputs, for example, different load forecasts, changes in resource costs, or other fundamental differences in inputs. The results of sensitivity analysis are not directly comparable to other analysis because they are based on different inputs, and not just different resource selections as in variant analysis.

Q. Should Schedule 100 resource valuation reflect any variant or sensitivity analysis?

A. In general, no. Rather than performing analysis with multiple possible portfolios the Company would recommend that the most representative portfolio be used, at present, which is the preferred portfolio presented in Chapter 9 of the 2025 IRP. While uncertainties remain, as with any plan, this portfolio includes carbon capture and sequestration on Jim Bridger units 3 and 4 and the Natrium™ nuclear power plant adjacent to Naughton, and those choices continue to represent the best expectation at this time.

This preferred portfolio also excludes new data center loads which would significantly increase resource needs on the Company's system, resource needs that are expected to be addressed via special contracts with individual customers. Any change to load forecasts should be paired with changes in the resource portfolio, and any sensitivity that increases load without identifying resource additions that would be appropriate in light of an ongoing resource shortfall would not be appropriate for setting the Schedule 100 resource valuation.

To the extent that an appreciable change occurs, modification of the preferred portfolio to account for the appreciable change is appropriate. This is analogous to the updates for signed contracts within the existing Schedule 38 methodology, which the Company would also incorporate for Schedule 100 resource valuation.

Q. Will the Company incorporate portfolio updates and assumptions that have not yet been published in an IRP or IRP Update?

A. The Company reserves the right to do so. The Company does not intend to develop endogenously optimized portfolios with and without a proposed Schedule 100 resource, as the optimization process may not be precise enough when considering a relatively small change to the Company's portfolio. If the Company has completed a separate portfolio optimization analysis, for example in a recently completed RFP process or other significant resource decision, it intends to use the best available portfolio information as part of its Schedule 100 resource valuation.

VIII. RESOURCE COST VALIDATION

Q. Will the Company use other available information when assessing whether results under the Schedule 38 methodology and the other analyses described above are reasonable?

A. Yes, to the extent such information is available. For example, the prices of recently contracted resources may be higher or lower than assumptions in the most recent IRP and could be an indication that a Schedule 100 resource is more or less valuable, relative to expected alternatives. The Company would note that care is required when assessing such information. For example, proxy solar resources in an IRP preferred portfolio might be replaced by alternative resource types if a significant cost increase occurs. These price results are also highly sensitive and cannot be released to all parties without risking harm to customers. Notwithstanding this limitation, this is information the Company would use when considering non-QF resource procurement on behalf of its retail customers.

IX. CONCLUSION

Q. Please summarize your recommendations for the Commission.

A. For each proposed Schedule 100 resource the Company will provide an estimate of the value using the methodology established for Electric Service Schedule No. 38 ("Schedule 38"), adjusted for the impact of transmission upgrade costs associated with the proposed Schedule 100 resource and the impact of the contract term beyond the production cost model study horizon. This value will be non-confidential.

The Company will also provide an adjusted valuation that incorporates REC value and any price-policy, risk, or other modifications it believes are appropriate to ensure the Schedule 100 resource value does not shift any costs or benefits to non-participating customers. Certain discussion and detail related to these cost elements will be confidential, to protect the Company's ability to negotiate the best contracts for resources and RECs on behalf of all customers.

Q. Does this conclude your direct testimony?

A. Yes.