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

Rebuttal Testimony of Daniel J. MacNeil

November 2025

Q. Are you the same Daniel J. MacNeil who previously provided direct testimony in this docket on behalf of PacifiCorp, d/b/a Rocky Mountain Power (the "Company")?

A. Yes.

I. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. My testimony responds to specific testimonies provided by the Community Renewable Energy Agency ("Agency"), Division of Public Utilities ("DPU"), the Office of Consumer Services ("OCS"), Western Resource Advocates ("WRA") and Sierra Club (collectively, "Parties") regarding the resource valuation methodology for the Utah Community Clean Energy Program ("CCEP" or "Program").

II. SUMMARY OF ISSUES AND RESPONSE

Q. How is your testimony organized?

A. Parties raise a variety of issues related to resource valuation that can be broadly organized into the following categories:

- Valuation methodology
- Schedule No. 38 modeling inputs
- Transmission costs
- Renewable energy credits ("RECs")

Each of these issues is addressed in a section of my testimony.

Q. Please summarize the Company's proposed valuation methodology for the CCEP.

A. The proposed valuation methodology is intended to mirror the analysis that the Company would perform for comparable long-term resource decisions made on behalf of non-participating customers. A prudent decision should have expected overall outcomes that are as good or better than other potential alternatives, and care must be taken to identify and assess the best potential alternatives. It is also appropriate to reassess input assumptions in light of evolving circumstances and new information. The approved Schedule No. 38 methodology provides an established starting point for analysis but might not represent the most appropriate outcome. The Company recognizes the need to clearly present and justify any alternative analyses of Program resources that it uses to support its resource valuation proposal and will present those alternatives along with the approved Schedule No. 38 methodology.

Q. Please summarize the Company's position on Schedule No. 38 inputs, transmission costs, and RECs.

A. Whenever PacifiCorp procures a long-term resource, it does so without perfect foresight into future conditions. As a result, any resource procurement could turn out better or worse than expected. It is reasonable for non-participating customers to face some risk of negative outcomes as a result of the procurement of a Schedule No. 100 resource, so long as that possibility is balanced by potential negative outcomes in the absence of a Schedule No. 100 resource. This balance of different risks is part of any long-term resource decision.

III. VALUATION METHODOLOGY

Q. Please summarize the valuation methodology recommendations made by parties.

A. Parties make the following valuation methodology recommendations:

- WRA recommends that resource valuation be based on a Present-Value Revenue Requirement differential ("PVRR(d)") analysis, with endogenous re-optimization of PacifiCorp's resource portfolio as a result of the addition of a Program resource.[1]

- The DPU suggests that stochastic risk assessment should not be part of the Program resource valuation and suggests additional evidence is needed to determine whether a weighting of valuations under different price-policy conditions is appropriate.
- The DPU expresses concern about the reliance of the partial displacement differential revenue requirement ("PDDRR") methodology on the specific Integrated Resource Plan ("IRP") preferred portfolio at the time a resource valuation is prepared and suggests that an annual update to avoided costs would prevent cost shifting.[2]

Q. As an opening point, did the Company propose that Program resource valuation be based on the PDDRR methodology approved for developing Schedule No. 38 avoided cost rates?

A. No. No single methodology is appropriate under all circumstances, and this is particularly true when underlying assumptions are in flux. Accordingly, the Company proposed providing a calculation of avoided costs based on the approved Schedule No. 38 methodology as well as incremental analysis to more thoroughly assess the potential benefits and risks of Program resources.[3] The long-term value of a Program resource should be determined in light of all available analyses and the facts and circumstances at the time the determination is being made. The incremental analysis is comparable to what would be performed for a long-term resource decision, which the Company would typically make on behalf of non-participating customers.

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[1] Direct Testimony Karl G. Boothman on behalf of Western Resource Advocates ("Boothman Direct"), at pgs. 8-10.
[2] Direct Testimony of Timothy M. Lenell for the Division of Public Utilities ("Lenell Direct"), at pgs. 28-31.
[3] Direct Testimony of Daniel J. MacNeil for Rocky Mountain Power ("MacNeil Direct"), at pgs. 2-3.

Q. Does PacifiCorp typically use endogenous portfolio re-optimization when assessing long-term resources using the PVRR(d) methodology?

A. Yes, but only for large-scale procurements, such as evaluation of large numbers of bids received in response to a Request for Proposals ("RFP") process. Even in an RFP, an initial analysis using endogenous portfolio re-optimization would be supplemented by variant analysis, with removals and additions of marginal bids (without full re-optimization) to assess the relative risks and performance of different combinations of resource selections. Endogenous re-optimization is not perfect. Endogenous resource selections by the PLEXOS Long-Term ("LT") model are based on a circumscribed view of future conditions that is not a comprehensive determination of the value of each resource in a portfolio and that does not necessarily identify the optimal quantities by location or by online date. As a result, adding or removing a one-hundred-megawatt resource could potentially result in lower costs, hence the need to evaluate marginal bids in order to avoid sub-optimal portfolio selections.

Q. Why is the risk of sub-optimal portfolio selections of significant concern?

A. The key issue is that the relative level of optimization may vary between the portfolio with a Program resource and the portfolio without a Program resource. Absent extensive analysis of alternative portfolio combinations, which is part of the comprehensive analysis performed in an IRP or typical RFP, it is difficult to determine whether a portfolio is sub-optimal and by how much. The only conclusive evidence is identifying a lower-cost outcome, but that does not preclude the possibility of even lower-cost outcomes that were not yet identified.

Q. How does sub-optimal portfolio optimization impact Program resource valuation?

A. If the portfolio with the Program resource is closer to optimal than the portfolio without the Program resource, there will be an apparent benefit from the Program resource, which would result in a high resource value. However, if that portfolio produces a better outcome, PacifiCorp could procure all of the other resources from that optimal portfolio while excluding the Program resource itself.

Q. Can the Company provide an example to illustrate how this situation might unfold?

A. Yes. In PacifiCorp's 2020 All-Source Request for Proposals ("2020AS RFP"), the Company tested different portfolio optimization approaches under various price-policy scenarios. Under medium natural gas, medium greenhouse gas ("MM") conditions, the best portfolio was endogenously optimized from a model with restricted wholesale sales (the "Staff No Sales" assumption) and assuming the low natural gas, no greenhouse gas ("LN") price-policy scenario. When the resulting LN-optimized portfolio was run under the MM price-policy scenario, it outperformed the portfolio that was endogenously selected under the MM price-policy scenario. This outcome would not be possible if endogenous portfolio selection resulted in perfectly optimized results—sometimes a portfolio optimized for one set of conditions performs better under different conditions than a portfolio optimized specifically for those conditions. This is possible because the PLEXOS LT model selects portfolios based on a simplified view of future conditions, and that simplified view is not the same as the full range of hourly conditions that are evaluated in the PLEXOS Short-Term ("ST") modeling used to evaluate portfolio results.

Q. Beyond uncertainty in the degree of optimization, are there any other concerns related to the PVRR(d) methodology using endogenous portfolio selection?

A. Yes. Endogenous portfolio selection is time-consuming, and the testing of possible alternatives necessary to find more optimal solutions is not very transparent. In an RFP, the possible alternatives in the near term are limited to the set of bids received, which are assumed to encompass all possible resource additions in the near term. Given the limited scope of the Program RFP, with a relatively small quantity under consideration and program-specific contract provisions, there is less information about potential alternatives that are available. With all that in mind, the Company would reiterate that it does not recommend using endogenous portfolio optimization to evaluate individual Program resources.

Q. In direct testimony, the Company identified that it might use an updated portfolio as the starting point for Program resource valuation.[4] Has the Company completed any recent portfolio optimization analysis relevant to Program resource valuation?

A. Not since the 2025 IRP was filed. Since the 2025 IRP, PacifiCorp has prepared portfolios for a Clean Energy Plan for Oregon and a Clean Energy Implementation Plan for Washington; however, the resource selections in these plans are primarily focused on Oregon and Washington requirements, respectively, and do not include a detailed reevaluation of cost-effective resource selections relevant to Utah customers. As a result, the 2025 IRP represents the best available resource portfolio at this time.

[4] MacNeil Direct, pg. 14.

Consistent with its most recent avoided cost inputs quarterly compliance filing, PacifiCorp recommends using the Final 2025 IRP preferred portfolio, presented in Chapter 9 of the Utah 2025 IRP, rather than the Utah 2025 IRP preferred portfolio, presented in Chapter 12 of the Utah 2025 IRP, which reflected assumptions as of PacifiCorp's draft IRP filing on December 31, 2024.[5] Given the 2025 IRP has been contested as part of the Schedule No. 38, at this time the Company intends to provide PDDRR results based on both the Utah 2025 IRP preferred portfolio and the Final 2025 IRP preferred portfolio, ensuring that results are available for both the current approved methodology, and for what the Company believes represents the best available information.

Q. How do you respond to the DPU's proposal to remove stochastic risk assessment from consideration in Program resource valuation, and the absence of a specific recommendation for assessing alternative price-policy forecasts?

A. The Company recommends that all available analysis should be presented for Parties to review, even if it is not quantitatively tied to the proposed resource valuation, so that risks can be assessed. With the current resource valuation analysis timeline, the Company does not anticipate any difficulty providing stochastic analysis of Program resources for the Parties' consideration. To the extent stochastic analysis is available, it is appropriate for Parties and the Commission to consider the resulting implications on resource value. In the same manner, alternative price-policy forecasts should be considered if they are available. The absence of a defined weighting for stochastic or

[5] *Rocky Mountain Power's 2025 Avoided Cost Input Changes Quarterly Compliance Filing*, Docket No. 25-035-30, Rocky Mountain Power's Quarterly Compliance Filing – 2025.Q2 Avoided Cost Input Changes (Sept. 30, 2025).

price-policy scenarios is intentional. The low natural gas-no greenhouse gas ("LN") price-policy scenario and high natural gas-high greenhouse gas ("HH") price-policy scenario are not developed based on a distribution of possible outcomes, so there is no inherent probability those conditions will occur. That does not mean that those risks should be ignored. The LN and HH price-policy scenarios serve as useful examples of unfavorable and favorable conditions that could potentially occur. The Company will present all of the applicable analysis, including a Program resource valuation proposal with weightings of specific results, as well as a justification for that proposal. Parties also will be able to propose a resource valuation based on their own weightings and justifications.

Q. How do you respond to the DPU's proposal to update Program resource valuation on an ongoing basis over the life of the resource, rather than a one-time analysis at the time of contract execution?

A. The Company believes a one-time analysis at contract execution remains the more appropriate and practical approach for several reasons. The intent of the Company's proposed resource valuation methodology was to identify appropriate costs and risk considerations for long-term resource decisions on behalf of non-participating customers. A one-time analysis is appropriate to the extent that the resource value is established at a level where the Company would have executed a contract for a long-term resource on behalf of non-participating customers. This is true despite the inherent uncertainty in long-term resource evaluation and the need to precisely apportion costs related to Program resources between participating and non-participating customers. In typical resource analysis, selected bids provide a benefit relative to other alternatives, such that uncertainty and changes in assumptions may diminish the expected benefits without changing the decision to move forward.

Updating resource valuation on an ongoing basis is likely to be more labor-intensive for and stakeholders, as it would require preparation and review for each year of the contract term. The Company understands the DPU's proposal to be for a one-year forecast, updated each year, but would highlight that most IRP planning does not include resource additions in the first several years, meaning that only executed contracts would be included in the portfolio. The absence of proxy resource additions in the first several years of an IRP or IRP Update would also preclude resource deferral under the PDDRR methodology, as a new IRP or IRP Update would generally be filed before a long-term proxy resource need was identified for the upcoming year for inclusion in an annual Program resource valuation update. The Company expects that, even with annual price updates, a production cost modeling approach may still result in disputes among the Company and various stakeholders about the appropriate modeling assumptions. The Company respectfully recommends that the Commission adopt the one-time resource valuation approach as proposed, which appropriately balances the need for reasonable cost allocation with regulatory efficiency and alignment with established resource planning practices.

Q. What is your recommendation for the resource valuation methodology?

A. Each Program resource valuation prepared by the Company will include a variety of analyses along with a recommendation for the appropriate long-term price that would leave non-participating customers indifferent. Parties will certainly have their own interpretation of the appropriate long-term price, and the Commission can make an appropriate determination of the value to non-participating customers and the incremental cost to be collected from Schedule No. 100 participants at the time of its approval of the Program resource. The Company does not believe this value needs to be revisited on an ongoing basis consistent with other prudently procured PPA resources.

IV. SCHEDULE NO. 38 MODELING INPUTS

Q. Please summarize the Schedule No. 38 modeling input recommendations made by parties.

A. Parties make the following recommendations:

- The Agency suggests the Company's solar capital cost de-escalation rate is erroneous.
- The Agency and Sierra Club recommend that avoided cost calculations reflect the loss of federal production tax credits ("PTCs").
- WRA recommends that the Company use an updated resource portfolio that accounts for system needs and resource adequacy requirements in addition to updated inputs like load forecast, resource costs, and tax credit developments.
- Sierra Club recommends that Program resources not be modeled with a negative dispatch price equal to the incremental cost.
- Sierra Club recommends an analysis using the social cost of greenhouse gases should be provided with any potential pricing recommendation the Company submits to the Commission for approval.

- Sierra Club suggests the Company should not have open-ended authority to impose additional pricing adjustments under the rubric of "other modifications" without full Commission review and an opportunity for intervenor input.

Q. Please describe the Agency's concerns related to the solar capital cost de-escalation rate assumed in the 2025 IRP.

A. The Agency identifies a solar cost-escalation correction that was identified in Company's current Schedule No. 37 avoided cost update,[6] and indicates that this correction would likely also apply under Schedule No. 38.[7] The Agency also expresses concerns about the solar cost de-escalation assumption generally, in light of supply chain and tariff uncertainty.

Q. Has the referenced solar cost-escalation correction been applied to Schedule No. 38?

A. Yes. This correction (and a related correction to wind cost-escalation) was identified as a routine update to Schedule No. 38 avoided cost inputs in PacifiCorp's September 30, 2025 quarterly filing.[8]

Q. Has PacifiCorp developed a new resource cost forecast?

A. Not at this time. PacifiCorp's resource cost assumptions for the 2025 IRP Update are expected to continue to reflect the 2024 Annual Technology Baseline used in the 2025 IRP but potentially with fewer adjustments so as to increase transparency. This would

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[6] *Rocky Mountain Power's Proposed Tariff Revisions to Electric Service Schedule No. 37, Avoided Cost Purchases from Qualifying Facilities,* Docket No. 25-035-T03, Rocky Mountain Power's Presentation for the June 18, 2025 Virtual Technical Conference (June. 18, 2025).
[7] Direct Testimony of Kevin C. Higgins on behalf of the Community Renewable Energy Agency ("Higgins Direct"), pgs. 13-14.
[8] *Rocky Mountain Power's 2025 Avoided Cost Input Changes Quarterly Compliance Filing,* Docket No. 25-035-30, 2025.Q2 Avoided Cost Input Changes Quarterly Compliance Filing (Sept. 30, 2025).

not result in a significant change in the cost assumptions.

Q. Is the application of an updated resource cost forecast under the Schedule No. 38 methodology appropriate?

A. No. The cost-effective resources identified in the 2025 IRP preferred portfolio (either the Utah version or the Final version) are only cost-effective relative to the assumptions used in that 2025 IRP. An increase in solar resource costs might result in those resources no longer being cost-effective. As a result, while it is reasonable to consider what solar resource costs might be given the many uncertainties that exist, inserting those assumptions in the Schedule No. 38 methodology is inappropriate, particularly without a broader consideration of cost-effectiveness.

Q. Should avoided cost calculations under the Schedule No. 38 methodology reflect a loss of federal PTCs?

A. No. For the same reason described above, it is not appropriate to modify assumptions in the Schedule No. 38 methodology without a broader consideration of cost-effectiveness.

Q. Can the Company use an updated resource portfolio that accounts for system needs and resource adequacy requirements in addition to updated inputs like load forecast, resource costs, and tax credit developments, as requested by WRA?

A. Not yet. The Company will have an updated resource portfolio that incorporates the requested inputs as soon as it files its 2025 IRP Update, which is expected on March 31, 2026. Consistent with the Schedule No. 38 procedures, the 2025 IRP Update assumptions would become immediately applicable for avoided cost calculations at that time. If the approval of Program resource values continues beyond the filing of the

2025 IRP Update, it may be appropriate for the Commission to consider updated analysis that reflects the 2025 IRP Update. The Company does not have an updated resource portfolio at this time.

Q. Will Parties and the Commission have the ability to assess the risks related to applying negative dispatch prices to Program resources?

A. PacifiCorp currently expects to model all Program resources with the assumption that they cannot be dispatched down (i.e., curtailed). This maximizes the production of RECs for the Program. The resulting resource value results will reflect a range of conditions, including some hours in which a Program resource may displace PTC-eligible resources. PacifiCorp will also report Program resource generation during all periods when the model reports locational marginal pricing that is below zero. If the Company is contractually allowed to curtail the Program resource during those periods, it may significantly increase the resource value, though at the expense of some RECs, with a proportionate increase in the cost per REC generated. Parties will also be able to dispute whether negative locational marginal pricing ("LMP") results based on the loss of PTCs are reasonable given recent changes in tax law, tariffs, and supply chains. The availability of this information should address the Sierra Club's concerns about negative dispatch prices, because it will have the data necessary to quantify its proposed adjustment to the dispatch and value of the Program resource.

Q. Does the Company intend to provide analysis using the social cost of greenhouse gases?

A. Not at present. If directed by the Commission, the Company can certainly provide analysis using its most recent social cost of greenhouse gases price-policy scenario. If directed by the Commission, PacifiCorp can certainly provide analysis using its most recent social cost of greenhouse gases price-policy scenario.

Q. Does the Company expect full Commission review and an opportunity for intervenor input each time a Program resource valuation is prepared, with particular focus on any additional pricing adjustments that it identifies?

A. Yes. The Company recognizes that it is uniquely suited to prepare Program resource valuation analysis, given its access to modeling tools and inputs. This does not necessarily mean the Company is suited to determine the appropriate balance of risks among the results of that analysis, and input from all intervenors should be considered when the Commission determines the value of a Program resource that will be attributed to non-participating customers and the incremental cost that will be collected under Schedule No. 100.

V. TRANSMISSION COSTS

Q. Please summarize the transmission cost recommendations made by parties.

A. Parties make the following recommendations:

- The DPU recommends that transmission upgrades should be categorized as either part of the IRP transmission plan or triggered by the Program resource.
- The DPU suggests costs related to transmission service requests should be assigned to Program participants if under the $1 million cap, or if over the cap, PacifiCorp should provide evidence of the quantifiable benefits of the upgrade and identify the allocation to Program participants.
- The DPU recommends that transmission costs be explicitly accounted for to ensure they remain within the Program.

- The Agency recommends that shared costs within a given cluster should reflect generator-specific cost allocation.
- The Agency also recommends that for "lumpy" transmission investments, only the proportion of the cost needed for the Program resource should be factored into the valuation.

Q. Is the IRP transmission plan a comprehensive assessment of the need for transmission upgrades?

A. No. PacifiCorp's IRP includes a simplified representation of the transmission system, specifically of the transmission rights used to serve its retail customers. Transmission upgrades in the IRP provide the ability to interconnect additional resources and/or the ability to transfer additional volumes between adjacent areas. As an example, the level of detail in the IRP model is insufficient to identify how growing loads might trigger the need for transmission upgrades within a transmission area, as the model has no restrictions between loads and resources within a single area of its aggregated topology. The IRP model also does not account for upgrades that might be triggered by reliability requirements or by requests from other transmission customers.

Q. Does PacifiCorp maintain a comprehensive assessment of the need for transmission and interconnection upgrades?

A. No. Due to the nature of transmission planning over a large and disparate geographic area, a separate transmission or interconnection study is performed for each new request (or cluster of requests) for transmission service, generation interconnection, and load interconnection. When evaluating a new request, all prior requests that are still pending are accounted for, and all of the network upgrades (transmission or interconnection) associated with those prior requests are assumed to be in service. Any change in the prior requests, including withdrawal, delay, or reduction in size, could impact the results for the new request, along with all of the requests that came after it. Each transmission and interconnection study identifies the network upgrades necessary to accommodate the specific request being evaluated. Each transmission and interconnection study also identifies network upgrades that were previously identified and are "contingent facilities", i.e., assumed in-service in the analysis and which could impact the cost or timing of the current request. Even after a study is completed, the results are subject to restudy and revision. For example, interconnection customers are invoiced based on the final cost after network upgrades are placed in service.

Q. Is it possible to know network upgrade costs with certainty at the time a contract is executed?

A. No. Because requirements may change and actual construction costs will evolve over time, transmission and interconnection upgrade costs are likely to be different from what was expected at the time of contract execution.

Q. How do generator interconnection customers manage the uncertainty related to transmission and interconnection upgrade costs?

A. Under PacifiCorp Transmission's Open Access Transmission Tariff ("OATT"), network upgrade costs paid for by generator interconnection customers are refunded over time with interest once the associated generation resources go into service, in recognition of the value to the transmission system as a whole that the network upgrades provide. As a result, these customers are relatively indifferent to the specific cost, though they may need to finance the upfront payment.

Q. Is it possible for transmission and interconnection upgrade costs for a Program resource to increase significantly?

A. Yes. The most likely cause of a significant cost increase is a prior request being withdrawn and a contingent facility that was assigned to that prior request instead of being assigned to the Program resource.

Q. Can PacifiCorp identify which Program resources might face reassigned contingent facility costs?

A. Yes. Contingent facilities are identified in each transmission and interconnection study, so potential risks to timing or cost related to the contingent facilities applicable to a Program resource can be evaluated. This concept is also present in IRP modeling, as earlier upgrades to a given area must be in place before later transmission and interconnection upgrades can be selected.

Q. Are reassigned contingent facilities more likely to be beneficial to the system than upgrades that are only necessary for a single request?

A. It is possible. To be considered a contingent facility an upgrade would have to be necessary for at least two requests (the request it was originally assigned to as well as the Program resource it was reassigned to). This could be an indication that the upgrade could provide broader benefits beyond what is strictly related to the Program resource. For example, an upgrade that was previously going to facilitate both an earlier request and the Program resource might instead facilitate both the Program resource and a future request.

Q. Given all of the above, what does PacifiCorp recommend with regard to the interconnection costs related to Program resources?

A. The best information about Program resource interconnection costs is what is identified in the resource's most recent study results, including the specific cost-allocation treatment among requests that are part of a cluster study. PacifiCorp can also verify the status of prior-queued requests, contingent facilities, and cost allocation estimates to ensure the most recent information is considered. Despite gathering the best available information at the time of execution, PacifiCorp cannot guarantee that the actual costs will be consistent with those estimates. However, this is true for any long-term resources PacifiCorp considers procuring on behalf of non-participating customers. PacifiCorp would thus recommend that interconnection costs be estimated at the time a Program resource's long-term value is established and held constant over the contract term, consistent with the consideration PacifiCorp uses for other long-term resource decisions. The risks associated with contingent facility costs also would be assessed. Contingent facility risks would be low if upgrades are likely to be necessary in the absence of the Program resource, for instance if they are also contingent for later-queued requests, particularly those selected in the IRP preferred portfolio. Contingent facility risks would be high if upgrades are not necessary for later requests and associated resources are not selected in the IRP preferred portfolio. The treatment of contingent facilities is necessarily somewhat qualitative, i.e., not readily captured in the resource valuation results, but could still be used to shift Program resource selections to lower risk outcomes by removing high risk options from consideration.

Q. Is PacifiCorp's proposed cost-allocation treatment for shared cluster study upgrades the same as that proposed by the Agency?

A. It appears so. Subject to change from any new information received, PacifiCorp proposes to use the cluster study cost allocation results specific to the Program resource.

Q. Is PacifiCorp's proposed cost-allocation treatment for "lumpy" upgrades the same as that proposed by the Agency?

A. Probably not. There are a wide range of possible circumstances, and PacifiCorp, the Agency, and other parties are likely to recommend different interpretations in different circumstances. The appropriate treatment is likely to depend on several factors, including whether a "lumpy" upgrade was identified as part of the IRP preferred portfolio, whether incremental resource selections are expected to be facilitated, and in what timeframe.

Q. Does PacifiCorp's proposed treatment of transmission upgrade costs apply to transmission service-related upgrades?

A. The same principles would apply, but the timing is different. The best available information about transmission service-related upgrade costs is not received until after a contract is executed and a designated network resource request is submitted and assessed. PacifiCorp's typical long-term resource contracts allow for termination when transmission service upgrade costs are received if the resulting costs exceed a threshold value. For the purpose of the Program, if the Agency opts to move forward when the transmission service study is completed, the forecasted costs in the study should be charged to the Program and held constant over the contract term. This mirrors

PacifiCorp's decision point for other long-term resources.

Q. Is the $1 million threshold for transmission service-related upgrade costs particularly relevant?

A. No. For PacifiCorp's typical long-term resource procurement, resource benefits generally exceed $1 million relative to the alternative, such that a cost up to that point would not change the decision, so having a threshold avoids unnecessary contract renegotiation or termination. For Program resources, it is PacifiCorp's intent to pass through all of the forecasted costs, if any, when the transmission service study is completed, regardless of the cost threshold. It would be up to the Agency to accept the forecasted costs or else the contract would be terminated. PacifiCorp agrees that it may be appropriate to waive the Program's cost responsibility to the extent there is evidence that the associated upgrades would otherwise have been cost-effective, for instance if they were part of the selections in the IRP preferred portfolio.

Q. Are PacifiCorp's proposals consistent with the DPU's recommendation that transmission costs be explicitly accounted for to ensure they remain within the Program?

A. No. As indicated above, actual transmission costs vary and actual transmission benefits evolve over time, such that explicit transmission cost accounting could become disconnected from cost causation. It is already extremely time-consuming to assess the necessary upgrades for new requests and it would be even more onerous to attempt to reassess the transmission system in the absence of particular upgrades to attempt to identify benefits. PacifiCorp cannot achieve perfect foresight in its long-term resource procurement, and a good forecast of transmission costs is reasonable for Program resources.

VI. RENEWABLE ENERGY CREDITS

Q. Please summarize the REC recommendation made by parties that you address.

A. The Agency and Sierra Club recommend that the resource valuation should not be adjusted for any lost value of RECs from a proxy renewable resource.

Q. Do Utah customers benefit from the RECs associated with renewable resources that are either owned or purchased on their behalf?

A. Yes. PacifiCorp monetizes the value of the renewable resources in its portfolio and credits customers through Schedule No. 98, REC Revenue Adjustment.

Q. Could RECs be more valuable in the future?

A. Yes. The value of RECs currently changes with demand for RECs, which can be used for compliance with renewable portfolio standards and clean energy policies in several states. Many electricity customers also have voluntary renewable resource procurement goals, not unlike the Program, which also drive demand. It is possible that RECs could have additional uses in the future. For example, eligibility for tax credits for clean hydrogen production requires the retirement of RECs.[9] Future federal policies related to taxes or emissions could include RECs as a component of compliance. Because California, Oregon, and Washington have greenhouse gas and clean energy policies that tighten over time, the demand for RECs (or the clean energy equivalent for nuclear or existing large hydro) in those jurisdictions will increase significantly in the coming

[9] *See* Internal Revenue Service Income Tax Regulations "Credit for Production of Clean Hydrogen and Energy Credit" (Jan. 10, 2025). Available at: https://www.federalregister.gov/documents/2025/01/10/2024-31513/credit-for-production-of-clean-hydrogen-and-energy-credit

years, potentially resulting in higher REC prices. Markets used to serve customers in those jurisdictions may also place a premium on generation from resources that have retained their RECs.

Q. Is the position of the Agency and Sierra Club regarding the lost REC value from proxy renewable resources reasonable?

A. No. To the extent non-participating customers are paying based on the all-in cost of a renewable resource, they would be entitled to all of the benefits associated with that resource, including energy, capacity, and renewable attributes.

Q. Are there circumstances in which lost REC value would not be applicable?

A. Yes. If resource value is not based on the cost of a renewable resource, lost REC value would not be applicable. For example, the annually updated avoided costs proposed by the DPU would be unlikely to include deferral of proxy resources, so REC value would not be relevant.

Q. Does this conclude your rebuttal testimony?

A. Yes.