Sophie Hayes (12546)
Western Resource Advocates
307 West 200 South, Suite 2000
Salt Lake City, UT 84101
801-212-9419
sophie.hayes@westernresources.org

Attorney for Western Resource Advocates

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of Rocky Mountain Power to Implement Community Clean Energy Program Authorized by the Community Clean Energy Act	DOCKET NO. 25-035-06

DIRECT TESTIMONY OF

KARL G. BOOTHMAN

ON BEHALF OF

WESTERN RESOURCE ADVOCATES

October 10, 2025

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I. INTRODUCTION AND QUALIFICATIONS

Q: Please state your name and business address.

A: My name is Karl Boothman. My business address is 307 West 200 South, Suite 2000, Salt Lake City, UT 84101.

Q: By whom are you employed and in what position?

A: I am employed by Western Resource Advocates (WRA) in its Clean Energy Program as a Senior Policy Advisor. WRA is a regional nonprofit advocacy organization that fights climate change and its impacts to sustain the environment, economy, and people of the West. WRA's Clean Energy Program develops and implements policies to reduce the environmental impacts of utilities in the Interior West by advocating for a western electric system that provides clean, affordable, reliable energy, reduces economic risks, and protects the environment through the expanded use of energy efficiency, renewable energy resources, and other clean energy technologies. WRA has offices in Salt Lake City, Utah; Boulder and Denver, Colorado; Reno, Nevada; Phoenix, Arizona; and Santa Fe, New Mexico.

Q: On whose behalf are you testifying in this proceeding?

A: I am testifying on behalf of Western Resource Advocates.

Q: Please describe your education and professional experience.

A: I provide policy analysis and regulatory support to WRA in electric-industry-related matters. I have a B.A. in economics, conferred with distinction from the University of

Michigan. From 2013-2016, I was employed as a Staff Analyst with ApplEcon LLC, a consultancy based in Ann Arbor, Michigan that provides regulatory and econometric support in litigation related to antitrust, collusion, and price fixing. From 2016-2019, I was employed as a Consultant and from 2019-2022 as a Senior Consultant with 5 Lakes Energy LLC, an energy policy consultancy based in Lansing, Michigan. In this role, I provided analysis for clients on a wide range of topics in the energy industry, including but not limited to, cost of service and rate design, energy efficiency and demand response, energy siting, and integrated resource planning. Since 2022, I have been employed as a Senior Policy Advisor with Western Resource Advocates where I have worked on Utah energy policy. In addition to my formal education and work experience, I have completed professional development courses including power grid school, utility accounting and ratemaking, and the annual regulatory studies program at Michigan State University Institute of Public Utilities as well cost of service, rate design, and depreciation courses with EUCI. A more detailed description of my qualifications is attached as Exhibit WRA__(KB-1).

Q: Have you previously testified before the Public Service Commission of Utah (Commission)?

A: Yes. I submitted direct, rebuttal, and/or surrebuttal testimony in Phase I, II, and III of Docket No. 24-035-04 (PacifiCorp General Rate Case) and Docket No. 20-035-34 (Application of Rocky Mountain Power for Approval of Electric Vehicle Infrastructure Program).

Q: Have you previously testified before a Public Service Commission in another jurisdiction?

A: Yes, I have submitted testimony in the following proceedings before the Michigan Public Service Commission:

- U-20561 (DTE Energy 2019 General Rate Case)
- U-20697 (Consumers Energy 2020 General Rate Case)
- U-20963 (Consumers Energy 2021 General Rate Case)

I have also filed comments and/or reply comments in the following non-litigated dockets before the Utah Public Service Commission:

- PacifiCorp's 2023 IRP (Docket No. 23-035-10)
- PacifiCorp's 2025 IRP (Docket No. 25-035-22)
- Investigation into Interconnection Rule Amendments (Docket No. 23-R312-01)[1]
- Schedule 37 Avoided Costs (Docket No. 25-035-T03)
- Solicitation Process for URC Program (Docket No. 24-035-55)

I have, or currently participate in, multiple stakeholder processes such as the DSM Steering Committee and DSM Advisory Group, RMP's Residential Time-of-Use Stakeholder workshops, RMP's wildfire workshops, RMP's Schedule 2E working group, RMP's Grid Modernization Collaborative, and the Multi-State Process (MSP).

Q: Please explain WRA's interest in participating in this proceeding.

[1] *See Comments of Western Resource Advocates*, Docket No. 23-035-10 (filed March 10, 2023; December 12, 2023; January 31, 2024; May 30, 2024; September 4, 2024); *Comments of Western Resource Advocates*, Docket No. 23-R312-01 (filed October 31, 2023); *Western Resource Advocates' Response to Proposed Amendments*, Docket No. 23-R312-01 (filed June 12, 2024).

A: As described in my introduction, WRA is a conservation organization that advocates for an electric system that provides affordable and reliable energy, reduces economic risks, and protects the environment with expanded use of energy efficiency, renewable energy, and other clean energy technologies. Our broader mission is to sustain the people, economies, and environments of the West by addressing climate change.

Q: Are other witnesses testifying for WRA?

A: No.

II. SUMMARY

Q: Please summarize your testimony and recommendations.

A: In my testimony, I identify aspects of the 2025 IRP that compromise its usefulness for Community Clean Energy Program (Program) resource valuation using the Schedule 38 avoided cost pricing methodology. I recommend the Company instead perform a Present-Value Revenue Requirement differential (PVRR(d)) analysis using project-specific information received by the Agency for its resource solicitation.

III. PROGRAM RESOURCE VALUATION METHOD

Q: What resource valuation methods have parties proposed for Program resources?

A: Christopher Thomas, testifying on behalf of the Community Renewable Energy Agency (Agency or CREA), represented the Community Renewable Energy Board's (Board) position:

> [The valuation of] Program Resources … should be calculated by comparing Rocky Mountain Power's expected system costs with and without Program Resources over such Program Resources' expected operating or contract life in a manner that is *consistent with Rocky Mountain Power's own resource procurement process* … with any deviations from such Utility Procurement Process clearly explained.[2]

This method is referred to as the present-value revenue requirement differential method (PVRR(d)).[3]

In contrast, Rocky Mountain Power (RMP) proposes using the "Schedule 38" avoided cost methodology applicable to non-standard Qualifying Facilities (QFs) as a starting point, supplemented with additional analyses. The net cost of the Program resource (not including administrative costs) would be the power purchase agreement (PPA) price, the value of renewable energy certificates (RECs) associated with Program resource generation, and any modifications necessary for interconnection or transmission upgrades, less the Schedule 38 avoided cost of the resource (i.e. the benefit).[4]

Q: Please describe the PVRR(d) method used by the Company in its own resource procurement and valuation process.

A: Resource procurements and valuation are usually addressed in rate case or resource procurement proceedings, where the Company must provide evidence that a resource, such as a new generation or transmission project, is just and reasonable and in the public

[2] *Direct Testimony and Exhibits of Christopher Thomas on Behalf of the Community Renewable Energy Agency*, Docket No. 25-035-06 (filed July 18, 2025) at lines 341-346 (emphasis added).
[3] *See, e.g.,* WRA Exhibit__(KB-2), Selected Data Request Responses from Docket No. 25-035-06 (specifically CREA Response to OCS Data Request 1.1 and Rocky Mountain Power Response to CREA Data Request 4.1, addressing the PVRR(d) resource valuation method).
[4] *Direct Testimony of Daniel J. MacNeil for Rocky Mountain Power*, Docket No. 25-035-06 (filed June 4, 2025) at lines 74-157 [hereinafter *MacNeil Direct Testimony*].

interest. To show this evidence, the Company uses its Integrated Resource Plan (IRP) modeling tool, PLEXOS, to calculate the change in system revenue requirement between modeling runs with and without the incremental resource(s). System revenue requirement is expressed as the present-value revenue requirement (PVRR) where capital costs are levelized over a fixed planning horizon and the sum of future system costs are expressed in present value terms. The Company runs multiple scenarios representing a range of future fossil fuel prices and proxy environmental costs known as price-policy scenarios but will select an "expected" price-policy scenario that represents the most likely future outcome at the time of modeling. The other price-policy scenarios are informative as to the robustness of the system costs or benefits of the incremental resource if future conditions differ from expectations. The difference in PVRR between a model run with the prospective resource and a model run without the prospective resource isolates the net system cost or benefit of the added resource(s). Each modeling run is endogenously optimized to account for the existence or lack of the prospective resource(s), such that the timing and necessity of other proxy resources and transmission across the system can change based on the impact or exclusion of the resource(s).

Q: Please explain the Schedule 38 Avoided Cost method.

A: The method for determining Schedule 38 avoided costs is the same as the Schedule 37 Partial Displacement Differential Revenue Requirement (PDDRR) method but includes QF generators in the queue with executed power purchase agreements. Under the PDDRR method, a zero-cost QF displaces a capacity contribution equivalent amount of a proxy resource, with wind, solar, and thermal resources displacing proxy resources of the same type (like-for-like displacement). The displaced megawatts of the proxy resource are removed from the portfolio, and the avoided fixed costs determine the QF's capacity payment.[5] This method uses the capacity expansion results from the most recent IRP, with minor periodic adjustments such as new fossil fuel and electricity market price forecasts. Avoided net power costs determine the QF's energy payment.

Q: Do you recommend a specific Program Resource valuation methodology?

A: Yes. I recommend the Company use the PVRR(d) method instead of a modified Schedule 38 avoided cost (PDDRR) method.

Q: Why should the Program Resource(s) be valued using the Present-Value Revenue Requirement Differential method instead of a modified Schedule 38 methodology?

A: Given the nature of Program resources and the statutory goals of the Community Clean Energy Program (CCEP), the PVRR(d) valuation method is more appropriate. The Schedule 37/38 avoided cost methodologies allow RMP to offer indicative pricing at terms satisfying the Public Utility Regulatory Policy Act's (PURPA) "customer indifference" standard. A QF decides whether the Company's indicative pricing is satisfactory to cover its costs and necessary return on investment. If it does, the QF and the Company can move forward with a PPA. This PURPA-based approach to resource

[5] *See, e.g., Rocky Mountain Power's Presentation for the June 18, 2025 Virtual Technical Conference*, Docket No. 25-035-T03 (filed June 18, 2025) at slide 4 [hereinafter *RMP's Sch. 37 Presentation*].

valuation allows for and encourages competition in the generation market up to, but not beyond, the point at which customers are indifferent in rates.[6]

In contrast, the Program is not bound by PURPA; rather, as a large-scale customer choice program, it is required that only participating customers pay a premium (or accrue benefits) for a Program resource. So, the CCEP requirements are already structured to account for additional costs or benefits. Within this construct, the CCEP's goal is to maximize incremental non-emitting generation given Program cost constraints to advance the Program's goal of 100% net-renewable energy by 2030. This is an important distinction and is a major reason for the Agency's solicitation process: the Agency is seeking to find the most cost-competitive mix of resources to maximize clean resource additions while maintaining a reasonable rate impact. A QF resource is not subject to competitive bidding and ratepayers are indifferent to resource development impacts because QF resources don't impact rates (theoretically).

Further, since a Program resource is not a QF, my understanding is that it will not be designated "must run" in PLEXOS modeling simulations.[7] Unlike QFs in Schedule 37/38 avoided cost pricing,[8] IRP resources and bilaterally negotiated resources are not required to generate in the model. Treatment of the Program resource as a non-curtailable QF in Schedule 38 valuation would be inconsistent. As a customer-funded resource, the

[6] There are many interpretations of what constitutes "indifference."
[7] *Direct Testimony and Exhibits of Kevin C. Higgins on behalf of the Community Renewable Energy Agency,* Docket No. 25-035-06 (filed July 18, 2025) at lines 318-321 [hereinafter *Higgins Direct Testimony*].
[8] *Recorded Live Stream of Virtual Technical Conference Held on June 18, 2025,* Docket No. 25-035-T03 (filed June 18, 2025) at approximately 28:30 [hereinafter *Recorded Live Stream Sch 37 Tech Conference*].

calculation of net costs for the Program resource should reflect the actual price of the PPA, not a generic utility avoided cost.

My main concern with using the Schedule 38 avoided cost method for Program resource valuation is that the method leads to extremely volatile results that may not realistically reflect the system's avoided costs. It is heavily dependent on the timing and technology of proxy resources in the Company's Preferred Portfolio. These resource selections are in turn heavily dependent on the Company's modeling methods and inputs, chosen price-policy scenario, and other choices. Whether a QF (or Program resource) earns a capacity payment would have an enormous impact on the Program's economics and viability. To provide an example, in its most recent quarterly filing, the Company's indicative solar QF pricing under Schedule 38 dropped from roughly \$25 to \$6.[9]

In contrast, the PVRR(d) method includes the Program resource primarily to calculate the system *benefits* of the resource (the costs would be known from the PPA terms). System benefits would accrue from avoided fuel expense and front office transactions over the life of the resource, as well as any avoided or delayed fixed costs of proxy resources that drop out of the portfolio or are delayed after endogenous re-optimization. Compared to the PDDRR method, PVRR(d) costs are more thorough and depend on the system's embedded resource mix and forecasted costs that, while impacted by IRP inputs, are unlikely to change nearly as markedly between published IRPs.

[9] *Rocky Mountain Power's Quarterly Compliance Filing – 2025.Q2 Avoided Cost Input Changes*, Docket No. 25-035-30 (filed September 30, 2025) at 3, available at [342021RMP2025Q2AvdCstInptChngs9-30-2025.pdf]().

Q: Do you have concerns with the Company's 2025 IRP that may impact the method and/or results of Program Resource valuation in this proceeding?

A: Yes. While the comment period of the 2025 IRP is ongoing, several Utah parties (including WRA) have expressed concerns with the Company's modeling assumptions, results, public input process, and portfolio selection. Specifically related to Program resource valuation, my primary concern is that the Company's bifurcated plan and ad hoc resource additions render the 2025 IRP unusable for this purpose. The Utah Commission has not yet issued an Order on the 2025 IRP, but it is my opinion that use of a bifurcated plan to determine Program resource benefits or costs in this docket is inappropriate. The underlying bifurcated nature of the 2025 IRP Preferred Portfolio renders the Schedule 38 valuation method unsuitable for valuing a Program resource because the timing and location of proxy resources for displacement were hand-selected rather than determined from a system-wide optimized model run. The 2025 IRP requires a significant overhaul, far beyond updating input assumptions.

Q: Briefly describe your concerns with the 2025 IRP.

A: While I have concerns with modeling inputs, the public input process, and the Company's portfolio selection, my primary concern with respect to resource valuation is the Company's new, bifurcated jurisdictional integration method.[10]

[10] For more detail on these concerns, see *Initial Comments of Western Resource Advocates,* Docket No. 25-035-22 (filed September 25, 2025).

A significant change introduced in the 2025 IRP was how the Company modeled and integrated three separate "Full Jurisdictional Portfolios" and imposed artificial siting and transfer limits to plan for a bifurcated, east-west system instead of an optimized single system. Just before the Final 2025 IRP was filed, the Company signaled that resources necessary to meet the resource adequacy and environmental compliance requirements of Oregon and Washington were constrained to being physically located on the west side of the system while Utah, Idaho, Wyoming, and California (UIWC) resources for resource adequacy were physically limited to the east side of the system, and **thermal units were reallocated to UIWC according to the policies of Oregon and Washington.**[11] To address the resulting compliance shortages, PacifiCorp hand-selected proxy resources in an ad hoc manner, such that there is little connection between the three system-optimized "Full Jurisdictional" portfolio runs and the final Preferred Portfolio. Altogether, the Company's choices were a deliberate departure from the dynamically-allocated, single-system planning that is designed to be least cost and least risk and is well-documented as the desired allocation and modeling approach from the Utah Commission.[12]

The "UIWC Full Jurisdictional Portfolio" *may* be more indicative of PacifiCorp's system needs than the bifurcated Preferred Portfolio, but whether it satisfied system resource adequacy requirements is indeterminable. The three Full Jurisdictional Portfolios (UIWC, OR, WA), despite being system-optimized runs, were modeled with Western Resource Adequacy Program (WRAP) compliance requirements to satisfy only a single

[11] *See id.* at 13.
[12] *See id.* at 18-22, especially n.53.

jurisdiction's load plus planning reserve margin (PRM), as opposed to the PRM of the entire system.[13]

Additionally, in previous IRPs, the Company has modeled a proxy CO_2 price to capture the effect of policies that incent reduced emissions. In a departure from recent IRPs, for the 2025 IRP, the Company chose a medium fossil fuel price and no CO_2 price-policy scenario (MN price-policy scenario). This modeling decision reduces the value of non-emitting resources (like wind and solar) relative to emitting resources (like coal or natural gas). The decision runs counter to the Company's frequent use of expected price-policy scenarios to justify its own resource procurements. As recently as the Company's 2024 general rate case (GRC), Company witness Rick T. Link testified, "The Company's price-policy scenarios include varying levels of assumed CO_2 costs to reflect the fact **it is more likely than not that some policy will exist that will drive reduced emissions over the life of the Transmission Projects.**"[14] As demonstrated in Mr. Link's 2024 GRC testimony, there is precedent for the Company to choose a price-policy scenario that represents the *most likely conditions* over the planning period or more specifically, *over the life of a resource.* Mr. Link testified further that "the LN [low fossil fuel prices/no CO_2 price] and MN [medium fossil fuel price/no CO_2 price] scenarios **unrealistically fail to account for the risk that there will be some form of policy action taken to impute a cost or penalty on greenhouse gas emissions over the planning period.**"[15] Notably, this statement was used as justification to *ignore* the PVRR(d) results under the LN and

[13] *Id.* at 40.
[14] *Direct Testimony and Exhibits of Rick T. Link for Rocky Mountain Power*, Docket 24-035-04 (filed June 28, 2024) at lines 404-409 (emphasis added).
[15] *Id.* at lines 579-581.

MN scenarios (these scenarios eroded the system benefits of the transmission resources being modeled). The Company's decision to pick a 2025 IRP Preferred Portfolio optimized under the MN scenario (medium fossil fuel price/no CO_2 price) is questionable considering the 21-year planning horizon of the 2025 IRP. I find the preference given to the MN scenario in the 2025 IRP and in this docket to be misguided.[16] A resource that provides significant benefits under other price-policy scenarios is expected to provide reliable, long-term benefits over the life of the contract or resource.

The Company made a late-breaking and unilateral decision to significantly reduce its 2025 IRP load forecast relative to the 2025 Draft IRP and the 2023 IRP Update. Again, in a departure from recent IRPs, the Company altered its treatment of large commercial (data center) loads by declaring these loads "outside of the traditional IRP planning process."[17] Removal of these loads was indiscriminate with respect to customer size, likelihood of coming online, and other important factors. The result of this decision was a reduction in proxy renewables and storage selected in the Final IRP and allocated to the UIWC jurisdiction.[18] As stated in WRA's IRP comments, the planning decision to remove large loads essentially provides a bookend scenario of what resources constitute an *underbuilt* Preferred Portfolio; if the Company connects even a single, incremental large commercial customer, all else equal, the system would be either resource

[16] Mr. MacNeil explains that "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." *MacNeil Direct Testimony*, supra note 4, at lines 286-288.
[17] PacifiCorp, 2025 IRP Public Input Meeting (January 22-23, 2025), at slide 17, https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2025-irp/January_22-23_2025_IRP_Public_Input_Meeting.pdf.
[18] Significant additions of wind and short duration battery storage were selected for UIWC in the Draft 2025 IRP but were delayed and/or decreased in the 2025 Final IRP.

insufficient or over-reliant on volatile market products. The Company's treatment of these loads was overly heavy-handed. Even Utah's SB 132 (2025), which allows non-utility generation for large loads if PacifiCorp is unable to provide service, applies specifically to customer requests greater than 100 MW.[19] The Company's "2026 Protocol" addresses new loads greater than 50 MW.[20] It's hard to believe that the challenge of serving a 1 MW load versus a 1,000 MW data center load request is equal, yet these two hypothetical requests both fall under the Company's blanket exclusion of large loads in the 2025 IRP.

Finally, the Company selected a suboptimal Preferred Portfolio (the Integrated Base MN Portfolio) based on the novel and speculative calculation of "end effects." Several portfolios outperformed the Preferred Portfolio on the established metrics of cost, stochastic risk, and environmental risk, but were ignored due to "end effects." This decision was not vetted with stakeholders and gave undue weight to highly uncertain modeling results outside of the planning horizon. Even in this proceeding, when discussing the valuation of a Program resource beyond the modeling horizon, the Company stated that extrapolating conditions from the last year of a planning horizon may "represent a transient condition…rather than something that is emblematic of all future years."[21]

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[19] *See* S.B. 132, 66th Gen. Assem., Reg. Sess. (Ut. 2025), https://le.utah.gov/~2025/bills/static/SB0132.html.
[20] *In the Matter of the Application of Rocky Mountain Power for Approval of the 2026 Inter-Jurisdictional Cost Allocation Protocol*, Docket No. 25-035-47.
[21] WRA Exhibit__(KB-2), Selected Data Request Responses from Docket No. 25-035-06, specifically RMP Response to OCS Data Request 2.9.

For these reasons, the 2025 IRP is unsuitable to use for Program Resource valuation using a Schedule 38 avoided cost method, where avoided costs vary greatly based on resource timing and location.

Q: Given these concerns with the IRP, what is your conclusion about the usefulness of the 2025 IRP for valuing a Program Resource?

A: My conclusion is that the 2025 IRP does not comply with the Commission's Guidelines and misidentifies *system* resource needs based on artificial locational constraints and is uninformative in its current form for a reliable determination of Program resource costs or benefits over the life of the resource. Handpicked resource additions and fabricated siting and transmission constraints compromise the key IRP outputs, most critically the location and timing of proxy resource needs. The validity of these outputs is foundational to technology-specific displacement of proxy resources, as in the PDDRR resource valuation method proposed by the Company; thus, a bifurcated plan should not be used.

Q: If the Commission approves the Company's proposal to use the Schedule 38 method, do you have any recommendations?

A: Yes. Because the avoided cost method is so dependent on the timing and location of proxy resources selected in the IRP, I would simply reiterate the importance of system planning over bifurcated planning. If the Schedule 38 method is approved, I recommend 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.

Q: If the 2025 IRP is unsuitable for use in an avoided cost context, is it usable for a PVRR(d) comparison?

A: The 2025 IRP Preferred Portfolio is not usable for a PVRR(d) comparison due to its bifurcated nature, but the Company could use its resource planning tool (PLEXOS), as informed by the 2025 IRP process, with updates, to simulate the Company's system with and without Program resources ("with-and-without" PVRR(d) analysis). I recommend the Company use the PLEXOS model to run with and without PVRR(d) analysis for the entire system using bids from the Agency's resource solicitation to evaluate resource value.

Q: Did the Company state why it prefers the PDDRR method over the PVRR(d) method?

A: The Company indicated that it intends to use the best available portfolio information as part of the Schedule 100 resource valuation (i.e. update the Preferred Portfolio with known changes) but believes that endogenous re-optimization of the portfolio with the Schedule 100 resource may not be precise enough given the "relatively small change" to the Company's portfolio.[22] I find this argument unconvincing for two reasons. First, PLEXOS is run at the hourly level of granularity. I see no reason why the precision of the model is incapable of accurately calculating benefits of, say, a 120 MW resource, yet the same model can presumably inform the value of smaller contracted resources, such as four new 80 MW battery storage projects (Enterprise, Escalante, Granite Mountain, Iron

[22] *MacNeil Direct Testimony, supra* note 4, at lines 364-370.

Springs) or Hornshadow I Solar (100 MW).[23] If the model is precise enough to justify Company resources, it should be precise enough for a Program resource.

Finally, the ultimate size of the change to the portfolio is unestablished. The size of the resource is ultimately dependent on the terms of bids received in the Agency's solicitation, as well as the resolution of all other outstanding issues in this docket that may impact the Program rate. For a concrete example, one must look no further than the discrepancy in Program resource size proposals between the Company (120 MW) and the Agency (600 MW). Surely a resource between 120 MW and 600 MW would not be considered small. When considering that the potential Program load of participating communities represents *more than half of Utah load*, the ultimate system impact of Program resources could be large.[24]

IV. REC VALUATION

Q: Why should the Company not retain the RECs associated with a Program Resource?

A: With respect to RECs, I echo the position of Agency witness Mr. Kevin Higgins in opposing the Company's proposal. Put simply, the Company proposes that the Program *purchase*, from non-participating customers, RECs associated with resources the Program itself acquires on behalf of participants. This is a nonsense proposal based on tenuous

[23] Or any of the Company's fourteen owned wind projects under 120 MW. *See* PacifiCorp's 2025 IRP Volume I at Chapter 6.

[24] RMP's Response to WRA Data Request 1.15 shows that on an energy basis load in participating communities has averaged roughly 52% over the past five years. WRA Exhibit__(KB-2), Selected Data Request Responses from Docket No. 25-035-06.

assumptions: that a Program resource will displace an IRP proxy resource that the Company would otherwise acquire; that the Company will necessarily be entitled to the RECs associated with that resource, even if it is a power purchase agreement; and that PacifiCorp will be able to monetize the RECs on behalf of customers at a specific value forecast years before (but not included in resource planning).

Agency witness Mr. Higgins points to flaws in the Company's proposal.[25] First, to paraphrase Mr. Higgins, if recent changes to PTCs are incorporated, it is an open question as to whether a Program resource will displace a resource of the same technology. A Program resource is an *incremental* resource funded by Program revenues from participating customers with an interest in being served by non-emitting generation. The acquisition of a Program resource need not adhere to the PURPA customer indifference standard of a Schedule 37 or Schedule 38 Qualifying Facility, nor does it displace a system resource in the near term. RECs should remain with the customers paying for the incremental costs of the resource, as it would not have been built by the Company but for the Program.

Second, allowing the Company to retain the RECs associated with the Program resource applies REC monetization benefits inconsistently across the resource planning and Program resource valuation venues. The Company does not incorporate a specific dollar value for RECs in IRP modeling and there is no assumed value for RECs relevant to Utah customers.[26] If RECs were valued in resource planning, the Company may have a better

[25] For a discussion of RECs, *see Higgins Direct Testimony, supra* note 9, at lines 407-438.
[26] Exhibit WRA___(KB-3), RMP's Response to WRA Data Request 2.14 in Docket No. 25-035-T03.

claim to retaining RECs. In this hypothetical, however, more renewables would have been selected by the model in the first place, making deferral of a planned system resource more likely.

The Company has no basis for claiming with any degree of certainty that Program resources will deprive non-participating customers of future REC revenues, let alone guess a price for such lost revenue years in advance. Hypothetical lost REC revenues are too uncertain to quantify in resource planning and therefore too uncertain to quantify here.

While it is not my preferred option, I also agree with Mr. Higgins that if the Commission finds that customers participating in the Program resource are obligated to compensate the Company for RECs, the Program should have the option of not retiring RECs on behalf of the Program and instead turn them over to the system, thereby eliminating the "lost value of RECs."[27]

V. RECOMMENDATIONS

Q: Please summarize your recommendations.

A: I recommend the following:

- The Commission should find that the PVRR(d) valuation method is more appropriate for Program resource valuation than the avoided costs (PDDRR) method.
- The Commission should direct the Company to use PLEXOS for system-optimized analysis as opposed to analysis based on bifurcated planning.

[27] *See Higgins Direct Testimony, supra* note 9, at lines 443-462.

- The Commission should reject the Company's proposal to charge participating customers for hypothetical, uncertain, and unquantifiable lost value of RECs.

Q: Does this conclude your testimony?

A: Yes.

I have read this filing and believe that it is supported in fact and in law.

Respectfully submitted,

WESTERN RESOURCE ADVOCATES

Sophie Hayes
Utah Clean Energy Manager/Senior Attorney
801-212-9419