BEFORE THE UTAH PUBLIC SERVICE COMMISSION

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

AND EXHIBITS

OF

KEVIN C. HIGGINS

On Behalf of

Community Renewable Energy Agency

July 18, 2025

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LIST OF EXHIBITS

Agency Exhibit 4.1	RMP Data Responses Referenced in Testimony

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Kevin C. Higgins. My business address is 111 East Broadway, Suite 1200, Salt Lake City, Utah, 84111.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am a Principal in the firm of Energy Strategies, LLC, a private consulting firm that specializes in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. My testimony is being sponsored by the Community Renewable Energy Agency ("Agency").

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS.

A. My academic background is in economics, and I have completed all coursework and field examinations toward a Ph.D. in Economics at the University of Utah. In addition, I have served on the adjunct faculties of both the University of Utah and Westminster College, where I taught undergraduate and graduate courses in economics. I joined Energy Strategies in 1995, where I assist private and public sector clients in the areas of energy-related economic and policy analysis, including evaluation of electric and gas utility rate matters.

Prior to joining Energy Strategies, I held policy positions in state and local government. From 1983 to 1990, I was economist, then assistant director, for the Utah Energy Office, where I helped develop and implement state energy policy. From 1991 to 1994, I was chief of staff to the chairman of the Salt Lake County Commission, where I was responsible for development and implementation of a broad spectrum of public policy at the local government level.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE UTAH PUBLIC SERVICE COMMISSION ("PSC" OR "THE COMMISSION")?

A. Yes. Since 1984, I have testified in 51 dockets before the Commission on electricity and natural gas matters.

Q. HAVE YOU TESTIFIED PREVIOUSLY BEFORE ANY OTHER STATE UTILITY REGULATORY COMMISSIONS?

A. In addition to these Utah proceedings, I have testified in approximately 260 other proceedings on the subjects of utility rates and regulatory policy before state utility regulators in Alaska, Arizona, Arkansas, Colorado, Florida, Georgia, Idaho, Illinois, Indiana, Kansas, Kentucky, Michigan, Minnesota, Missouri, Montana, Nevada, New Mexico, New York, North Carolina, Ohio, Oklahoma, Oregon, North Carolina, Pennsylvania, South Carolina, Texas, Virginia, Washington, West Virginia, and Wyoming, as well as the Bonneville Power Administration. I have also filed affidavits in proceedings before the Federal Energy Regulatory Commission and prepared expert reports in state and federal court proceedings involving utility matters.

Q. HAVE YOU TESTIFIED PREVIOUSLY ON THE SUBJECT OF PACIFICORP'S AVOIDED COSTS?

A. Yes. In 1984, I participated in the Commission's initial determination of avoided costs for sales from Qualifying Facilities ("QFs") to PacifiCorp's Utah predecessor, Utah Power & Light Company. Since then, I have periodically participated in PacifiCorp avoided cost cases in Utah, Wyoming, and Oregon. I have also participated in numerous cases involving the determination of transition adjustments for direct access customers in Oregon, which involves a series of calculations similar to the determination of avoided costs for QFs.

Q. PLEASE DESCRIBE YOUR INVOLVEMENT IN THE AGENCY'S EFFORTS TO ADVANCE THE OBJECTIVES OF THE COMMUNITY CLEAN ENERGY ACT.

A. For the past several years I have provided consulting support to the Agency in its collaboration with Rocky Mountain Power ("RMP" or "Company") to implement the Utah Community Clean Energy Program ("Program"). The primary focus of my consulting support has been in the area of rate design and resource valuation for ratemaking purposes, with a particular emphasis on ensuring that the acquisition of an Agency resource would result in just and reasonable rates for participants, as well as not shift costs or benefits to nonparticipating customers.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony addresses rate design and resource valuation pertaining to the Program.

Q. PLEASE SUMMARIZE YOUR PRIMARY CONCLUSIONS AND RECOMMENDATIONS.

A. I offer the following conclusions and recommendations:

- It is reasonable to establish Program rates using a "top-down" rate design, as discussed in my testimony.
- The Commission should expressly require that if Program benefits exceed Program costs, then Schedule 100 should reflect a net credit to Program participants to ensure that the Program does not shift costs or benefits to nonparticipating customers.
- If a Schedule 38 approach is used to determine the Program resource valuation, then the assumptions would need to be updated to reflect the fact that under recently enacted budget and tax legislation, renewable resources coming on line in 2028 or later will not be eligible for production tax credits ("PTCs") unless construction on the project begins within one year of enactment of that legislation. In addition, RMP's current Schedule 38 assumption that the capital cost of a solar tracking generating plant will decline 25%

between 2025 and 2032 appears to be erroneous and would require correction before it could be used in valuing the Program resource.

- RMP's proposal to charge program participants for "the lost value of RECs" as part of the resource valuation calculation should be rejected by the Commission. However, if the Commission accepts RMP's proposal and requires Program participants to pay for the RECs the Agency wishes to retire, then the Commission should offer the Agency the option of declining to retire the RECs from the Program resource, and instead turn over the RECs produced by the Program resource to the system as a whole.

II. RATE DESIGN

Q. WHAT IS MEANT BY THE TERM "RATE DESIGN"?

A. In the context of utility regulation, rate design refers to the structure of the rate schedules under which customers take service, particularly the various charges on each rate schedule.

Q. IN YOUR DISCUSSIONS WITH RMP, WERE YOU ABLE TO COME TO A COMMON UNDERSTANDING AS TO THE RATE DESIGN FOR PROGRAM PARTICIPANTS?

A. At a high level, yes. An important point on which we agree is that Program pricing would be implemented through a "top-down" rate design.

Q. WHAT IS A "TOP-DOWN" RATE DESIGN?

A. In general, a top-down rate design starts with current rates and then adjusts the current rate *up* to recover the incremental *costs* of a program, as well as *down* to credit its incremental *benefits*. The net effect of the simultaneous increase in costs and benefits can be reduced to a single net cost (or net benefit) per kWh. This net cost (or net benefit) can be recovered (or credited) through a separate rider applied to the participant's current rate for the portion of their service that is associated with a special product or program.

In the case of the Program, the top-down rate design keeps each participating customer on their current rate schedule. The portion of their service that is provided by (or attributable to) the Program resource(s) would be subject to Schedule 100 as proposed by RMP.

Q. IS A TOP-DOWN RATE DESIGN DISTINGUISHABLE FROM A BOTTOM-UP RATE DESIGN?

A. Yes. A bottom-up rate design would unbundle and separately price the various service functions that the utility provides the customer, such as distribution, transmission, generation, and ancillary services, and then *exclude* from the customer's bill the utility service that the customer is providing from a separate source (and paying for separately). In theory, a top-down and a bottom-up rate design ought to arrive at the same total price, although in practice that might not actually occur, in part because current bundled rates typically diverge from cost of service, as well as the fact that it is difficult to price and quantify the ancillary services that a utility provides in support of its retail customers.

For a participant in a resource acquisition program, the structure of a bottom-up rate design might seem more intuitive than a top-down design, but from an implementation standpoint, a bottom-up approach is a far more complicated to achieve. For example, in the case of the Program, it would require each of RMP's various rate schedules to be "unpacked" and repriced on an unbundled basis. I concluded early in this process that a top-down rate design would be far more practical to administer.

Q. YOU STATED THAT YOU AGREE WITH RMP AT A HIGH LEVEL CONCERNING THE USE OF A TOP-DOWN RATE DESIGN. ARE THERE DETAILS ABOUT WHICH YOU DISAGREE?

A. Yes. Earlier in my discussion, I stated that, in general, the net effect of a simultaneous increase in costs and benefits from a program can be reduced to a single net cost or net *benefit* per kWh. In the case of the Program, this means that if the benefits of the Program, such as avoided energy costs, were to exceed the costs of the Program (*i.e.*, resource and administrative costs), then Schedule 100 should result in a net credit to participating customers.

RMP disagrees, as indicated in its Response to Agency Data Request 1.7.[1] RMP states that it opposes allowing Schedule 100 to provide a credit to Program customers. According to RMP:

> Providing a benefit to participants of the Utah Community Clean Energy Program would mean collecting the avoided cost benefit from a Schedule 100 resource that were to exceed the cost of acquiring the Schedule 100 resource ("hypothetical benefit") identified from other non-participating customers to pay participating Utah Community Clean Energy Program customers. The Company interprets that having non-participating customers pay for a "hypothetical benefit" violates the requirement that non-participating customers not be impacted by any cost or benefit shifts to any non-participating customers as per the approved House Bill (HB) 411 legislation.

Q. WHAT IS YOUR RESPONSE TO RMP'S POSITION THAT SCHEDULE 100 CANNOT BE A CREDIT?

A. The Company's position is unreasonable and appears to plainly violate the statutory requirement that the Program not shift costs or *benefits* to nonparticipating customers.[2] At a minimum, the Project resource(s) will allow the Company to avoid incurring energy costs

[1] *See* RMP Response to Agency Data Request 1.7, included in Agency Exhibit 4.1.
[2] *See* Utah Code § 54-17-904(4)(b) (directing that Program rates "may not result in any shift of costs or benefits to any nonparticipating customer, or any other customer of the qualified utility beyond the participating community boundaries.").

from running its thermal units or purchasing power from the wholesale market. If the selected resource from the Request for Proposals ("RFP") issued by the Agency results in a purchased power price (plus administrative costs) that is less than the value of the avoided energy and other savings made possible by the resource, and the Company fails to pass that net benefit on to the Program participants through a Schedule 100 credit, then the Program would be transferring that net benefit to nonparticipants through lower costs, which would most likely be passed on to nonparticipants through the Energy Balancing Account ("EBA"). Such a benefit-shift would not be consistent with the requirements of the statute. Just as Program participants should be responsible for any net costs of the Program, they should be entitled to any net benefits if they should occur.

Q. IN ITS DISCOVERY RESPONSE, RMP REFERS TO THE CIRCUMSTANCE OF A SCHEDULE 100 BENEFIT EXCEEDING THE SCHEDULE 100 COST AS A "HYPOTHETICAL BENEFIT." WHAT IS YOUR RESPONSE TO THIS CHARACTERIZATION?

A. If we were to accept this characterization, then it would be equally true that the benefits analysis that RMP uses to justify the billions of dollars of capital projects it puts into rate base are also merely "hypothetical benefits." RMP uses this pejorative characterization to claim erroneously that providing a credit to Program participants if the Program resource produces net benefits to the system would somehow cause a cost shift to non-participants. This claim is absurd on its face.

To see this point, consider a simple example. Assume the Agency acquires the Program resource for $40 per MWh. Now assume that the value of the energy it is projected to avoid in a given year averages $30 per MWh and administrative costs average

$2 per MWh. It is obvious from this example that the Schedule 100 charge to Program participants would be $12 per MWh in that year.[3]

But now assume that in a different year, the avoided cost of energy is projected to be $45 per MWh. The resource still costs $40 per MWh and the administrative costs remain $2 per MWh. But instead of a credit equal to $3 per MWh, Schedule 100 would be set at $0, according to the Company. RMP asserts that even though the system is avoiding $45 per MWh in power costs due to the power that the Program resource is producing, it cannot recognize the $3 in net savings as a credit to Schedule 100 because the non-participants would "pay" for it – even though RMP (and customers) would have had to pay $45 per MWh for that power anyway but for the energy produced by the Program resource. These savings would be realized by non-participants through lower costs in the EBA. It is clear from this example that RMP's proposed restriction on Schedule 100 is arbitrary and would transfer benefits to non-participants.

Q. ARE THERE OTHER ASPECTS IN WHICH RMP'S PROPOSED RESTRICTION ON SCHEDULE 100 IS UNREASONABLE?

A. Yes. According to RMP's Response to Agency Data Request 2.1, RMP does <u>not</u> anticipate that the net cost of the Schedule 100 resource would be levelized, but rather that "Schedule 100 rates in each year would use the net cost for that year, as calculated at the time of contract execution and approved by the Public Service Commission of Utah (UPSC)." RMP explains that:

> A levelized net cost and the stream of nominal net costs upon which it was based would be expected to result in equal net present values. However, the recovery of those net cost streams over time would be different. The

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[3] $40/MWh + $2/MWh -$30/MWh = $12/MWh.

> difference between the levelized net cost and the stream of nominal net costs in a given year is inherently a cost shift between participating and non-participating customers in that year, even if it is expected to cancel out over the life of the resource on a net present value (NPV) basis. Levelization frequently results in higher value at the start of a contract term relative to the nominal value in those years, which could represent additional risk related to repayment.[4]

The implication of RMP's opposition to levelizing the Schedule 100 charge is that the charge to participants could be greater in the early years and lower in the later years. But yet in the later years, if the Schedule 100 calculation would provide benefits greater than costs, RMP would deprive participants of the credit associated with that later benefit, despite charging Participants more in the early years of the project so as to not shift costs over time. The Company's position in inherently unfair and, although I am not attorney, appears to be in direct conflict with statutory requirements.

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION REGARDING PROGRAM RATE DESIGN?

A. I recommend that the Commission approve the top-down rate design as proposed for Program participants but expressly require that if Program benefits exceed Program costs, then Schedule 100 should reflect a net credit to Program participants to ensure that the Program does not shift costs or benefits to nonparticipating customers.

[4] *See* RMP Response to Agency Data Request 2.1, included in Agency Exhibit 4.1

III. RESOURCE VALUATION

Q. WHAT IS THE ROLE OF RESOURCE VALUATION IN THE CONTEXT OF THE PROGRAM?

A. At the broadest level, the resource valuation will determine the net cost or net benefit of the Program resource(s). In simple terms, the net cost of a Program resource will be the cost of the power purchased from the resource developer and other incremental costs incurred by RMP to support the project, minus the benefits provided by the resource, which will largely consist of avoided costs.

Q. IN YOUR COLLABORATIVE DISCUSSIONS WITH RMP, HAVE YOU TALKED ABOUT RESOURCE VALUATION?

A. Yes, we've discussed this subject at length.

Q. IN YOUR OPINION, DID RMP AND THE AGENCY REACH A COMMON UNDERSTANDING AS TO HOW THE RESOURCE VALUATION WOULD BE CALCULATED PRIOR TO RMP'S PART II APPLICATION FILING ON JUNE 4, 2025?

A. No. But we did not necessarily disagree either. There simply was not enough specificity about the method the Company would ultimately use to agree or disagree about it. One of my objectives during the collaborative process was to reach agreement with RMP on a specific calculation method for determining the valuation of a Program resource. Ideally, we would have vetted the method with the Office of Consumer Services and the Division of Public Utilities prior to filing. However, we were unable to get to the point in our collaboration where a specific illustrative calculation was endorsed by the Company. To underscore the challenge in trying to reach a complete understanding on this point, when asked in discovery in this docket whether RMP agreed that prior to selecting a shortlist of six prospective Schedule 100 resources from the ongoing Program solicitation for PacifiCorp to value, the Agency should have the opportunity to review in detail the valuation mechanics that the Company intends to use, the Company indicated that it disagrees that the Agency should have the opportunity to review all aspects of the valuation mechanics prior to that analysis being conducted.[5]

Q. DO YOU BELIEVE THE PROGRAM SHOULD HAVE THE OPPORTUNITY TO REVIEW IN DETAIL THE VALUATION MECHANICS OF THE AVOIDED COST CALCULATION PRIOR TO SELECTING A RESOURCE?

A. Yes. The Agency needs to have this information to ensure that any resource it acquires will provide the greatest possible benefit to reduce Program rates.

Q. HAVE YOU REVIEWED THE DIRECT TESTIMONY OF RMP WITNESS DANIEL J. MACNEIL CONCERNING RESOURCE VALUATION?

A. Yes.

Q. WHAT IS YOUR REACTION TO MR. MACNEIL'S DISCUSSION OF THIS SUBJECT?

A. At a basic level, I agree with Mr. MacNeil that the resource valuation calculation involves determining the incremental benefits of the Program resource. A fundamental incremental benefit is the avoidance of energy costs that would have been incurred absent the Program resource. Theoretically, the Program resource could also cause the Company to avoid capital investment costs, although as I will discuss later in my testimony, under current

[5] *See* RMP Response to Agency Data Request 1.5, included in Agency Exhibit 4.1.

circumstances, it is difficult to speculate about what capital costs would be avoided by the initial Program resource and when those capital costs would be avoided.

Mr. MacNeil's reference point for his discussion of the resource valuation method to be used for the Program resource is the calculation of avoided costs for non-Standard Qualifying Facilities ("QFs") in accordance with Schedule 38. Mr. MacNeil identifies four different modifications to the Schedule 38 analysis that he believes are required when valuing the Program resource: interconnection costs, transmission service costs, REC valuation, and valuation estimates for the life of the contract beyond the production cost model study horizon.[6]

Q. DO YOU AGREE THAT SCHEDULE 38 IS THE APPROPRIATE POINT OF DEPARTURE FOR VALUING THE PROJECT RESOURCE?

A. It depends on whether the analysis is updated to reflect the impact on production tax credits ("PTCs") due to the "One Big Beautiful Bill Act" recently enacted by Congress. My understanding is that according to that legislation, solar and wind projects will no longer be eligible for production tax credits ("PTCs") unless they are under construction within one year of enactment or else completed by the end of 2027. A key element of the Schedule 38 avoided cost calculation is the assumption that the QF (or in this case, the Program resource) will displace the Company's acquisition of a resource using the same or similar technology at some date in the future. According to the current Schedule 38 calculation, the next displaceable resource for a solar tracking project is a proxy solar plant located in Willamette Valley, Oregon that would be displaced in 2032.[7]

[6] Direct Testimony of Daniel J. MacNeil, lines 74-77.
[7] Docket Nos. 03-035-14 and -25-035-30, 2025.Q1 Avoided Cost Input Changes Quarterly Compliance Filing, Appendix A, p. 4.

In accordance with the assumptions currently used in the Schedule 38 analysis, the capital cost of that Oregon project would be 25% *lower* than the cost of a solar project coming into service today[8] and the project would also be eligible for PTCs. Both of these assumptions drive *down* significantly the avoided cost calculation for a Schedule 38 solar tracking resource. Similarly, these assumptions, if applied to the Program resource, would drive down the calculated benefits of the resource and increase its net cost to Program participants.

Q. WHY DOES THE ASSUMPTION THAT A DISPLACED RENEWABLE RESOURCE WOULD BE ELIGIBLE FOR PTCS DRIVE DOWN THE CALCULATED BENEFITS OF A PROGRAM RESOURCE?

A. In accordance with the Schedule 38 calculation method, if a QF project (or Program resource) displaces a future resource that would have generated PTCs, the displacement of those future PTCs counts as a *lost benefit* in the calculation of the QF's avoided cost. In other words, displacing PTCs materially reduces the avoided cost price that is offered to the QF. If the Schedule 38 approach is used to determine the Program resource valuation, then it would need to be updated to reflect the fact that under current law, renewable resources coming on line in 2028 or later will not be eligible for PTCs unless construction on the project began within one year of enactment.

[8] Utah PSC Docket No. 25-035-30, RMP's Schedule 38 2025.Q1 Avoided Cost Quarterly Compliance Filing, Avoided Cost Input Changes, RMP Attachment 2 – Appendix B.2 workpaper. In this workpaper, RMP projects the current build cost of an Oregon cited solar resource will decline from $1,290/kW to $1,029/kW by 2032. As I discuss later in my testimony, RMP noted in a June 18, 2025 technical conference that it made an error in its application of cost escalation rates it applied to the Schedule 37 IRP proxy resource costs. Since the avoided cost pricing methods are similar for both Schedules 37 and 38, a similar error was likely made in the Schedule 38 quarterly filing as well.

Q. DO YOU HAVE ANY CONCERNS ABOUT THE PROJECTED COST OF CONSTRUCTING A SOLAR RESOURCE AS CURRENTLY USED IN THE SCHEDULE 38 CALCULATION?

A. Yes. As I noted above, RMP's capital cost assumptions assume that the capital cost of a tracking solar project will *decline* 25% between 2025 and 2032. This assumption has the effect of suppressing QF or Program resource benefits because the displaced resource is assumed to be relatively inexpensive compared to current costs. RMP noted in a June 18, 2025 technical conference that it made an error in its application of cost escalation rates it applied to the Schedule 37 IRP proxy resource costs. Since the avoided cost pricing methods are similar for both Schedules 37 and 38, a similar error was likely made in the Schedule 38 quarterly filing as well. I assume that this error will be corrected prior to valuing the Program resource. The correction of this error notwithstanding, the assumption of a substantial decline in capital costs strikes me as aggressive in light of supply chain uncertainties exacerbated by US tariff policy and is potentially problematic in determining a reasonable Program resource valuation.

Q. DO YOU HAVE ANY OTHER CONCERNS ABOUT THE ASSUMPTIONS USED IN THE SCHEDULE 38 ANALYSIS?

A. Yes. If a Schedule 38 approach is used to determine the Program resource valuation, it should account for flexibility in the operation of a Program resource when determining avoided energy costs. QFs are "must run" resources, meaning that they cannot be curtailed even when it is economic to do so. I understand that the Company utilizes such a modeling constraint when conducting a Schedule 38 avoided cost analysis for QF resources. The Program resource is not a QF and need not be a "must run" resource. To the extent flexibility is built into the power purchase agreement allowing the Company to curtail the Program resource in certain hours, the Program valuation should account for that flexibility

.Q. WHAT MODIFICATIONS DOES MR. MACNEIL PROPOSE FOR SCHEDULE 100 RELATIVE TO THE CURRENT SCHEDULE 38 ANALYSIS?

A. Mr. MacNeil proposes four modifications with respect to Schedule 100 resource valuation: interconnection costs, transmission service costs, REC valuation, and valuation estimates for the life for the contract beyond the production cost model study horizon.[9]

Q. PLEASE EXPLAIN MR. MACNEIL'S PROPOSAL REGARDING INTERCONNECTION COSTS?

A. Mr. MacNeil explains that the cost of upgrades to interconnect with the transmission system are paid for by QFs, whereas when transmission system upgrades are needed to accommodate a non-QF resource, the cost of the upgrades is initially funded by the developer of the resource, but it is refunded over time, with interest. Mr. MacNeil concludes:

> 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.[10]

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[9] Direct Testimony of Daniel J. MacNeil, lines 74-77.
[10] *Id*., lines 86-92.

Q. WHAT IS YOUR RESPONSE TO MR. MACNEIL'S PROPOSAL REGARDING INTERCONNECTION COSTS?

A. While I agree that interconnection costs are likely to represent an incremental cost of a Project resource, it is important from a valuation perspective to recognize certain nuances. Specifically, since the costs incurred by the developer for interconnection Network Upgrades are subject to refund over time, RMP's modeling of the revenue requirement impacts must accurately reflect the timing of the rate base impacts. In particular, the Company would not be making the initial capital investment and therefore would not be entitled to earn a return on that rate base until it begins refunding the developer's capital outlay.

Additionally, many interconnection Network Upgrade costs are shared among generator interconnections within a given cluster. As such, only the generator-specific cost allocation should be included in the Schedule 100 valuation.

Moreover, approximately 80% of PacifiCorp Transmission's network upgrade costs are allocated to the Company's retail jurisdictional customers through the formula rate approved by FERC, with third-party transmission customers paying the remaining 20%. Accordingly, only 80% of the interconnection Network Upgrade costs attributed to the Program generation resource—costs that will ultimately be allocated to the Company's retail customers—should be considered for valuation purposes. This is consistent with the Company's proposed approach regarding transmission service Network Upgrades.

It is also important to consider that transmission investments are typically "lumpy," often resulting in excess capacity beyond what is needed to mitigate the specific overload that necessitated the interconnection Network Upgrade. To the extent that excess capacity is created and provides benefits beyond merely interconnecting the Program resource, only the proportion of generator allocated interconnection Network Upgrade costs that corresponds to the capacity needed to mitigate the generator interconnection should be factored into the valuation.

Finally, if the resource valuation is conducted within the Schedule 38 analytical framework and the analysis includes a displaced resource, then the avoided interconnection costs of the *displaced resource* must be considered a benefit attributed to the Project resource. If RMP includes interconnection costs in the valuation calculation, then the Commission should require the treatment to be symmetrical.

Q. PLEASE EXPLAIN MR. MACNEIL'S RECOMMENDATION REGARDING TRANSMISSION SERVICE NETWORK UPGRADE COSTS.

A. Mr. MacNeil explains that after a contract with a Schedule 100 resource is executed, the Company will submit a request to PacifiCorp Transmission to designate it as a network resource. If insufficient capacity will be available after the *interconnection* Network Upgrades are in-service, then additional *transmission service* Network Upgrades may be identified. According to Mr. MacNeil, the following technique would be appropriate as part of the evaluation of a Schedule 100 resource using the following inputs:[11]

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.

[11] *Id.*, lines 104-113.

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)"[12]

Q. ABOVE YOU RECOMMEND THAT ONLY THE PROPORTION OF INTERCONNECTION NETWORK UPGRADE COSTS THAT CORRESPONDS TO THE CAPACITY NEEDED TO MITIGATE THE GENERATOR INTERCONNECTION SHOULD BE FACTORED INTO THE VALUATION. SHOULD THAT SAME PRINCIPLE APPLY TO TRANSMISSION SERVICE NETWORK UPGRADE COSTS?

A. Yes, it should. To the extent that an identified transmission service Network Upgrade creates excess capacity beyond what is needed to deliver the generation from the Program resource to the Company's retail loads, the system benefits resulting from that excess capacity should be factored into the valuation.

[12] *Id*., lines 114-126.

Q. WHAT IS YOUR RESPONSE TO MR. MACNEIL'S PROPOSAL TO CHARGE PROGRAM PARTICIPANTS FOR "THE LOST VALUE OF RECS" AS PART OF THE RESOURCE VALUATION CALCULATION?[13]

A. I strongly disagree with this proposal and recommend that it be rejected by the Commission. A core objective of the Program is to increase the utilization of renewable energy. To advance that objective, the Agency will cause new generation resources to be built, with Program participants responsible for paying the incremental cost of such Program resources through the Schedule 100 charge. In light of this effort and associated cost responsibility and risk, it follows that the Agency would desire to retire the RECs generated by the Program resource. Yet RMP proposes that the Program must effectively buy – from the nonparticipants – the RECs that the Program resource produces.

The (thin) logical thread in the Company's narrative here turns on the assumption that the Program resource will displace a proxy resource that the Company would otherwise acquire in the future. The Company's reasoning is that the future proxy resource would produce RECs that could be sold for the benefit of Utah customers. If the proxy resource is displaced by the Program resource, then future Utah customers would be deprived of the benefit of those future REC sales. Therefore, RMP proposes to increase the cost of the Program resource by charging Program participants for the estimated value of future RECs attributed to the proxy resource that does not get built.

There are several problems with this argument. First, it turns on the assumption that the Program resource will indeed displace a proxy resource that uses the same

[13] *Id.*, lines 153-157.

technology as the Program resource. As I have previously explained, with the recent change in the law governing the future availability of PTCs, this assumption is probably invalid, particularly as it pertains to a solar resource. Absent the assumption that a REC-producing proxy resource would be deferred by the Program resource, the Company's argument for charging Program participants for "the lost value of RECs" falls apart.

Second, the future value of RECs has not been, and is not currently, part of the quantification of generation project benefits. Mr. MacNeil admits that the Company's IRP does not assign a value to RECs produced for Utah consumers.[14] Nor are REC values attributed to renewable energy projects in the net benefits analysis that the Company conducts for its own projects when they are brought into rate base in a general rate case. As the valuation of RECs is not part of the standard practice of resource valuation in Utah, and do not factor in to the avoided cost calculations underlying the Program resource valuation, the Commission should not approve an exception that "bolts on" such a valuation to the unreasonable detriment of Program participants.

Q. YOUR RECOMMENDATION NOTWITHSTANDING, IF THE COMMISSION DECIDES TO REQUIRE PROGRAM PARTICIPANTS TO PAY FOR RECS THE AGENCY WISHES TO RETIRE, ARE THERE OTHER OPTIONS THAT SHOULD BE CONSIDERED?

A. Yes. If the Commission accepts RMP's proposal and requires Program participants to pay for the RECs the Agency wishes to retire, then the Commission should offer the Agency the option of declining to retire the RECs from the Program resource and instead turn over

[14] *Id*. lines 148-152.

the RECs produced by the Program resource to the system as a whole. This action would eliminate the alleged lost value of the RECs attributed to the displaced proxy resource and thereby remove the valuation of these RECs from the calculus. While such an outcome would not fully align with the Agency's objectives, it is only reasonable for the Commission to give the Agency the opportunity to consider the economics of the added Program costs that would result from adopting RMP's proposal.

As I envision it, a decision by the Agency to decline to retire the RECs should be exercised at the start of a Program resource's life, as it would implicate the resource valuation and the Schedule 100 rate. Further – and importantly – if the Commission adopts the Company's proposal to charge Program participants to pay for the RECs the Agency wishes to retire – and if the Agency declines to retire them but instead turns the RECs back to the Company – then the value of the RECs produced by the Program resource *prior* to the assumed displacement of the proxy resource should be *credited* to the Program resource as a benefit. In other words, if the Commission accepts the Company's argument that RECs need to be included in the resource valuation, then it is equally true that incremental RECs produced by the Program resource and used for the benefit of the system as a whole should be valued in the same manner and credited to the Program resource.

Q. CAN YOU PROVIDE A SIMPLE EXAMPLE TO ILLUSTRATE THIS POINT?

A. Yes. Assume that the Agency selects a solar tracking resource to be the inaugural Program resource and it goes into service January 1, 2028. Assume further that the Commission accepts the current Schedule 38 premise that the next displaceable resource for a solar tracking project is a proxy solar plant that would be displaced in 2032. And also assume that the Commission accepts RMP's argument that Program participants must pay for the

RECs the Agency wishes to retire but also accepts my recommendation that, if such a determination is made, the Agency should be given the option of declining to retire the RECs from the Program resource.

If the Agency decides to retire the RECs, then RMP's resource valuation would assign a *cost* to the Program resource equal to the value of the RECs that could have been sold from the proxy solar plant had it not been displaced starting in 2032.

But suppose the Agency declines to retire the RECs and instead turns them over to the system as a whole. In this case there are no costs associated with "foregone" REC sales starting in 2032. But in addition, the Program resource would have generated incremental RECs for the benefit of the system from 2028 through 2031. Since these RECs would be used for the benefit of the system (i.e., sold for the benefit of Utah customers) the value of those estimated sales should properly be credited to the Program resource as an incremental benefit – if the Commission accepts the argument that REC valuations should be included in the analysis in the first place.

Q. WHAT IS YOUR RESPONSE TO MR. MACNEIL'S STATEMENT THAT THE SCHEDULE 38 ANALYSIS SHOULD BE MODIFIED TO CONSIDER VALUATION ESTIMATES FOR THE LIFE OF THE CONTRACT BEYOND THE PRODUCTION COST MODEL STUDY HORIZON?

A. I do not disagree in concept, but reserve judgment regarding the reasonableness of any particular calculation until it is presented in full.

Q. DO YOU HAVE ANY RESPONSE TO MR. MACNEIL'S RECOMMENDATION THAT THE MN PRICE-POLICY SCENARIO SHOULD BE GIVEN THE GREATEST WEIGHT IN VALUING THE PROGRAM RESOURCE?[15]

A. I do not object to valuing the Program resource using the MN price-policy scenario, which corresponds to medium natural gas prices and no federal CO2 regulations. However, I find Mr. MacNeil's discussion of the role of other price-policy scenarios in the context of the Program resource valuation less clear. It is true that the Company considers multiple price-policy scenarios when justifying its own projects, but those multiple valuations are in the context of supporting a Yes/No decision. In contrast, the Program resource valuation must be reduced to a single value. A single price-policy scenario should suffice for that purpose, although the results of other price-policy scenarios might be of interest.

Q. DO YOU HAVE ANY COMMENTS ON MR. MACNEIL'S DISCUSSION OF STOCHASTIC RISK ASSESSMENT?

A. Yes. In my recent experience reviewing the results of the Company's stochastic risk assessments, I note that the risk assessments increased the estimated benefits from the Company's investment decisions, such as Gateway South. It will be interesting to see them applied to the Program resource.

Q. SHOULD THE VALUE OF THE PROGRAM RESOURCE BE FIXED IN ADVANCE BASED ON THE PROJECTED BENEFITS AND COSTS AT THE TIME OF THE VALUATION?

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[15] *Id.,* line 288.

A. It is my understanding based on my discussions with the Company during the collaborative process that the Company prefers that the valuation be fixed up-front, based on projected benefits and cost, rather than modified over time based on actual avoided energy costs. The Agency has agreed with this approach, at least for the initial Program resource.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.