ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

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October 31, 2017

VIA ELECTRONIC FILING

Utah Public Service Commission
Heber M. Wells Building, 4th Floor
160 East 300 South
Salt Lake City, UT 84114

Attention: Gary Widerburg
Commission Secretary

RE: **Docket No. 17-035-T07 - In the Matter of Rocky Mountain Power's Proposed Tariff Revisions to Electric Service Schedule No. 37, Avoided Cost Purchases from Qualifying Facilities**
Docket No. 17-035-37 – In the Matter of Rocky Mountain Power's 2017 Avoided Cost Input Changes Quarterly Compliance Filing

The Company hereby provides for filing its Rebuttal Testimony as directed by the Commission. The Company will post its confidential workpapers to the Commission's secure website. Rocky Mountain Power respectfully requests that all formal correspondence and requests for additional information regarding this filing be addressed to the following:

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Informal inquiries may be directed to Jana Saba at (801) 220-2823.

Sincerely,

Jeffrey K. Larsen
Vice President, Regulation

Rocky Mountain Power
Docket No. 17-035-T07/
17-035-37
Witness: Daniel J. MacNeil

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Rebuttal Testimony of Daniel J. MacNeil

October 2017

Q. Are you the same Daniel J. MacNeil who presented direct testimony in this proceeding?

A. Yes.

PURPOSE OF TESTIMONY AND RECOMMENDATION

Q. What is the purpose of your rebuttal testimony?

A. My testimony responds to the direct testimony filed on October, 3, 2017 by Abdinasir M. Abdulle for the Division of Public Utilities ("DPU"), Cheryl Murray for the Office of Consumer Services ("OCS"), John Lowe and Neal Townsend for the Renewable Energy Coalition ("Coalition"), and Ken Dragoon and Kate Bowman for Utah Clean Energy ("UCE").

Q. Please summarize the issues in this proceeding.

A. The Company's June 21, 2017 Avoided Cost Input Changes Quarterly Compliance Filing (2017.Q1 Filing) included four routine updates and two non-routine updates to avoided cost pricing for large qualifying facilities ("QFs") under Schedule 38. Parties challenged three of these updates, specifically:

- Routine updates associated with the 2017 Integrated Resource Plan ("IRP"), including updates to the sufficiency period/deficiency period, deferrable resources, and the preferred portfolio;
- A non-routine update to renewable energy credit ("REC") ownership; and
- A non-routine update to post-IRP resource expansion plan pricing.

In addition, the Company proposed modifying the Schedule 37 avoided cost methodology for small QFs to be the same as the methodology for large QFs under Schedule 38.

Q. Have Parties' concerns related to some of these issues been addressed?

A. Yes. None of the Parties oppose the Company's non-routine updates to REC ownership and post-IRP resource expansion plan pricing. The disposition of RECs is impacted by some of the proposals by the Coalition and UCE, and is discussed in more detail in my response to those proposals.

Q. What are Parties' positions on the avoided cost methodology for Schedule 38?

A. The current Schedule 38 avoided cost methodology, as implemented by the Company, is supported by OCS and DPU. The Coalition and UCE propose changes to the Schedule 38 methodology that fall into four categories:

- The Coalition and UCE oppose limiting deferral to "like" renewables.
- The Coalition proposes that all renewable QFs have the option to be paid either a renewable avoided cost rate or a non-renewable avoided cost rate.
- The Coalition and UCE propose that all resources be eligible to defer the 2021 wind and transmission resources included in the Company's IRP preferred portfolio.[1]
- UCE proposes that the existing Proxy/Partial Displacement Differential Revenue Requirement ("Proxy/PDDRR") methodology be used to establish capacity payments based on deferrable thermal resources, with a floor on avoided costs based on the cost of renewable resources in the preferred portfolio, after applying adjustments to account for project specific characteristics.[2]

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[1] The 2021 Wyoming wind resources are assumed have a December 31, 2020 in-service date to ensure the assumed tax benefits are achieved.
[2] Dragoon Direct at 9-10, lines 167-186.

Each of these proposals is addressed in a separate section of my testimony. While the Coalition raises concerns related to the potential QF queue, it is not making any specific recommendations related to the QF queue.[3] Other Parties' concerns with the potential QF queue are limited to its use in determining rates under Schedule 37, as discussed below.

Q. What are Parties' positions on the Company's proposed avoided cost methodology for Schedule 37?

A. The Company's proposal to apply the Schedule 38 methodology to Schedule 37 rates is generally supported by OCS and DPU, with the exception of the implementation of the QF queue. The Coalition and UCE object to the Company's proposed change to Schedule 38, thus they recommend no change to the existing Schedule 37 methodology. In addition, UCE proposes that Schedule 37 rates for QFs on the distribution system be adjusted to include avoided line losses.

Q. Please summarize your conclusions.

A. The approved Schedule 38 methodology produces a reasonable estimate of the Company's avoided costs and should not be modified at this time. When resource acquisitions during the rate effective period are accounted for by including a reasonable portion of the potential QF queue, the Schedule 38 methodology also produces appropriate prices for Schedule 37 rates. In addition:

- Deferring like-for-like resources using the specific rules described later in my testimony produces the most accurate avoided costs by maintaining a reasonable balance of cost and risk consistent with the IRP preferred portfolio.

[3] Lowe Direct at 7-8, lines 84-88.

- The Coalition's proposal to allow Utah QFs to choose between renewable and non-renewable avoided cost rate options is not consistent with the Public Utility Regulatory Policies Act of 1978 ("PURPA") regulations and Federal Energy Regulatory Commission's ("FERC') precedent and should be rejected.
- Assuming deferral of the 2021 wind and transmission by resources outside of the constrained area of Wyoming does not result in a reasonable estimate of the Company's avoided costs. After accounting for the loss of production tax credits ("PTCs") which will no longer be available when a QF's contract expires, avoided costs are higher under the Company's proposal than when deferral of 2021 wind resources is assumed.
- UCE's renewable price floor proposal produces inaccurate avoided costs by ignoring geographic and operational differences between renewable resources and by failing to account for the aggregate effects of QFs on the Company's portfolio and system. Further, to the extent the IRP evaluated resource options that are of the same type and location as a QF, the absence of those resources in the preferred portfolio is evidence that their costs are in excess of avoided costs. The cost of the IRP resource options represents an avoided cost ceiling and does not rely upon undefined adjustments as in UCE's proposal.

AVOIDED COST PROCEDURES

Q. The Coalition claims that the inputs that determine the Company's pricing may not be formally reviewed or acknowledged by the Commission. Is this accurate?

A. No. All avoided cost pricing is subject to public process and Commission approval, either through approval of the tariff, in the case of Schedule 37, or through approval of the contract negotiated under Schedule 38. The Company identifies the updates to the inputs to avoided cost pricing for Schedule 38 on a quarterly basis and parties receive access to the Generation and Regulation Initiative Decision Tool ("GRID") studies supporting the pricing of contracts filed for Commission approval. The Company also responds to data requests submitted by parties, both in contract approval dockets and in response to informal requests before contract execution. To the extent parties believe it is necessary, I believe reasonable requests for additional review of contracts would be viewed favorably by the Commission.

DEFERRAL OF LIKE RENEWABLES

Q. Please provide an example illustrating the current resource deferral methodology used by PacifiCorp.

A. The 2017 IRP preferred portfolio includes a total of 1,040 megawatt ("MW") of solar resource additions between 2028 and 2036, as well as four major thermal resource additions between 2029 and 2033.[4] Since the preparation of the 2017 IRP, the Company has executed contracts with 153 MW of solar resources, and terminated the contract of a 5 MW solar resource. These executed contracts defer all of the IRP solar additions in 2028 and 2029, and a portion of the IRP solar additions in 2031 (there were no IRP solar additions in 2030). After accounting for these signed contracts, 72.4 MW of east tracking solar resources remain in the IRP preferred portfolio in 2031, while an additional 70 MW of west fixed solar resources and 167 MW of east tracking solar

[4] PacifiCorp's 2017 IRP Volume I. Table 8.17. Utility Solar – PV- Utah-S and Utility Solar – PV – Yakima. Available online at: www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/2017_IRP_VolumeI_IRP_Final.pdf.

resources are included in 2032.[5] PacifiCorp has also executed contracts with baseload resources representing 4 MW of capacity contribution and which defer a portion of the 200 MW 2029 simple cycle combustion turbine ("SCCT") in the 2017 IRP preferred portfolio.

Q. What would an 80 MW tracking solar QF in Utah located first in the QF queue defer?

A. An 80 MW tracking solar QF would first defer the remaining 72.4 MW of east tracking solar resources in 2031. Because the QF has the same capacity contribution, this is a one for one deferral. The remaining 7.6 MW of QF capacity would defer 8.4 MW of west fixed solar resources in 2032. The capacity contribution of west fixed solar resources is 53.9 percent, which is slightly less than the 59.7 percent capacity contribution of the east tracking solar QF in this example. As a result, the QF defers slightly more of the IRP proxy resource on a nameplate basis.

Q. What would an 80 MW baseload QF in Utah located first in the QF queue defer?

A. An 80 MW baseload QF would defer an additional 80 MW of the 2029 SCCT.

Q. Is there a circumstance under which a solar QF would defer the 2029 SCCT?

A. Yes. If no solar resources remain in the IRP preferred portfolio during a QF's proposed contract term, the QF would be assumed to defer thermal resources, such as the 2029 SCCT. This is identical to the circumstances prior to the 2017 IRP, when there were no cost-effective solar resources in the IRP preferred portfolio.

Q. Why is deferral of solar resources in 2031 preferable to deferral of the SCCT in 2029?

[5] PacifiCorp's 2017 IRP Volume I. Table 8.17.

A. The IRP process culminates in the identification of a *portfolio* of resources, which in combination represent the least-cost, least-risk alternative among available options. The 2017 IRP preferred portfolio includes a 200 MW 2029 SCCT rather than an equivalent capacity contribution from an additional 335 MW of Utah tracking solar resources in 2029. This indicates that the 2029 SCCT has characteristics which contribute to a least-cost, least-risk portfolio in a manner which the solar resources do not. The Proxy/PDDRR methodology can account for capacity contribution equivalence, but it does not take into consideration all of the operational and risk characteristics which led the portfolio optimization in the 2017 IRP to conclude that the 2029 SCCT was preferable to additional solar resources. Instead it is appropriate for the Proxy/PDDRR methodology to preferentially align the operational and risk characteristics of QFs and resources being deferred to maintain equivalence with the preferred portfolio.

Q. Please illustrate that maintaining an equivalent capacity contribution is insufficient to maintain the least-cost, least-risk characteristics of the preferred portfolio.

A. The 2017 IRP preferred portfolio includes a range of resource types, which indicates that the specific characteristics of a combination of different resources together supports least-cost, least-risk outcomes. This is because a resource’s impact on the portfolio is based on more than just capacity equivalence, otherwise there would be no need to run portfolio optimization models at all, as we would merely pick the lowest cost capacity resource available. UCE acknowledges that more than capacity cost is relevant to developing a preferred portfolio.[6] As shown in Table 1R below, while an SCCT may provide lower-cost capacity, the other characteristics of combined cycle combustion turbines ("CCCTs"), solar, and wind resources make them valuable components of a portfolio optimized to serve customers in all hours of the year, rather than just during a single peak.

Table 1R: Capacity-Equivalent Cost by Resource Type

		2029 SCCT	2030 CCCT	UT Solar	2021 Wind
Fixed Cost ($/kw-year, 2017$)	a	$84	$146	$164	$157
Capacity Contribution (%)	b	100%	100%	59.7%	15.8%
Capacity-Equivalent Cost ($/kw-year, 2017$)	c = a / b	$84	$146	$275	$991

Q. Are there circumstances under which solar resource additions are considered relative to potential additions of thermal resources and wind?

A. Yes. PacifiCorp's portfolio optimization process evaluates all resource options in combination and is employed in the IRP and in the evaluation of bids submitted in response to Requests for Proposals ("RFPs"). This is a lengthy process which is not suitable for QF pricing given the volume of requests PacifiCorp receives each year.

Q. Please summarize your basis for maintaining the current resource deferral methodology employed for pricing of QFs under Schedule 38.

A. The Proxy/PDDRR methodology relies on GRID to forecast the avoided cost of energy, not the avoided cost of capacity or the composition of a least-cost, least-risk resource portfolio. PacifiCorp's position is that the GRID model, when properly applied, produces a reasonable estimate of avoided energy costs. It is necessary, however, to calculate the avoided cost of capacity by deferring like-for-like resources because doing so maintains a reasonable balance of cost and risk that is consistent with the IRP

[6] Dragoon Direct at 11, lines 210-211.

preferred portfolio.

Q. What is the overarching principle behind PacifiCorp's position?

A. The overarching principle is the customer indifference standard.[7]

Q. What is the overarching principle behind the position of the Coalition and UCE?

A. Both the Coalition and UCE appear to be advocating for renewable resource equivalence. For instance, the Coalition proposes that all renewable QFs be offered a renewable rate.[8] Likewise, UCE proposes an avoided cost floor based on a renewable proxy in the IRP preferred portfolio that would be applicable to any renewable QF resource.[9] While renewable resources may share certain characteristics, such as being "renewable", those characteristics are only pertinent to avoided costs insofar as they impact customer indifference. This is discussed in more detail in the next section. More importantly, both the Coalition and UCE fail to present evidence that their proposed methodologies produce more accurate avoided costs than the current methodology, and therefore should be rejected.

<u>RENEWABLE AND NON-RENEWABLE AVOIDED COST OPTION</u>

Q. The Coalition proposes that a renewable QF should have the option to choose between either a renewable or non-renewable avoided cost rate.[10] How do you respond?

A. Avoided cost rates must meet the customer indifference standard. FERC has established precedent for states implementing multi-tiered avoided cost rates. In an

[7] MacNeil Direct at 5, fn 2 & 3.
[8] Lowe Direct at 8, lines 107-115.
[9] Dragoon Direct at 10-11, lines 193-207.
[10] Lowe Direct at 8, lines 100-105

order dated January 20, 2011, FERC held that "the state may take into account obligations imposed by the state that, for example, utilities purchase energy from particular resources of energy for a long duration."[11] Renewable Portfolio Standards ("RPS") are one example of such obligations. Because PacifiCorp does not have an RPS or any other obligation to procure renewable resources in Utah, there is no basis for implementing a renewable resource option for Utah QFs.

Q. Does this mean that avoided cost rates can't be based on the cost of renewable resources?

A. No. PacifiCorp isn't obligated under PURPA to pay more for renewable resources in Utah than the costs it would otherwise incur, but the costs it would otherwise incur could include acquisition of cost-effective renewable resources. The corollary is also true, that PacifiCorp would not pay less for renewable resources than it would otherwise incur. Thus, in the absence of state obligations requiring specific resource types and justifying multi-tiered rates, a single rate is established that is equal to the avoided costs.

Q. How are renewable avoided cost rates typically implemented?

A. Generally, renewable avoided cost rates are paid based on the incremental value of RECs transferred from a QF to the utility, based on the value of those RECs for RPS compliance.

Q. Does REC ownership impact the capacity and energy value associated with a QF?

A. No. REC ownership has no impact on PacifiCorp's treatment of QF output when calculating avoided energy and capacity costs because system operations and dispatch

[11] 134 FERC ¶ 61,044 at 18 (Jan. 20, 2011).

would be the same for a given project regardless of REC ownership.

Q. Mr. Lowe suggests that renewable avoided cost rates could be higher or lower than non-renewable avoided cost rates. How do you respond?

A. I have already established above why the capacity and energy provided by a given QF project in Utah has a single avoided cost. To the extent renewable generation costs are less than the costs of equivalent non-renewable resources, after accounting for differences in operational characteristics including capacity and energy value, then those renewable resources should be present in the Company's preferred portfolio. This is exactly the situation in the 2017 IRP preferred portfolio, which includes three different kinds of renewable resources. To the extent substantial opportunities exist to acquire renewable resources at costs lower than those identified in the 2017 IRP preferred portfolio, the customer indifference standard would dictate that the Company seek competitive bids to acquire the lowest cost opportunities, as it is currently in the process of doing.

Q. The Coalition indicates that some QFs may wish to retain the RECs they produce. Is this issue pertinent to avoided costs?

A. Possibly, though potentially not in this proceeding. The disposition of RECs produced by Utah QFs is clearly within the jurisdiction of the Utah Commission, as is compensation insofar as it impacts avoided costs. The Commission could allow QFs to negotiate to buy back RECs which the Company may be entitled to, with Commission approval of the negotiated result on a case by case basis. Because the Schedule 38 avoided cost methodology may be applicable to Renewable Energy Facilities under Utah Schedule 32, which explicitly relates to customer acquisition of renewable energy, this question may be more appropriate to consider in a proceeding specific to that rate schedule.

Q. Should a REC buyback rate also be available to QFs that have RECs to sell?

A. No. There is no need to extend the must-take obligation under PURPA to RECs, particularly when there is no obligation to acquire RECs for Utah customers. It is inappropriate for the Company to prospectively buy RECs at a fixed rate in anticipation of achieving benefits selling those RECs to support customers in other jurisdictions. While the Company acquires RECs for several purposes including other states' RPS obligations and its Blue Sky program, those purchases typically occur through competitive processes and have detailed compliance parameters consistent with state specific programs.

DEFERRAL OF 2021 WIND AND TRANSMISSION

Q. The Coalition states that "the Company considers the 2021 Wyoming wind resource to be such a good deal for customers that the Company will acquire as much of it as it physically can, irrespective of the availability of other supplies such as QF power, limited only by the transfer capability of the transmission system to deliver the 2021 Wyoming Wind to load."[12] Is this statement accurate?

A. Yes. The Commission order in Docket No. 17-035-23 approving the Company's RFP for wind resources explicitly stated that if the Company went forward without including solar resources in the RFP, it would have to defend that decision. The Company's analysis of the top performing portfolio of wind assets identified from the RFP will include sensitivities to determine whether that portfolio would still provide customer

[12] Townsend Direct at 21, lines 446-450.

benefits if low-cost solar resources were also included in the portfolio. The Company suspects that while sufficiently low-cost solar resources will provide customer benefits, they will not eliminate the benefits associated with the Wyoming wind and transmission proposal, hence its decision to move forward without including solar resources in the RFP.

Q. The Coalition states that the Company's demand for long-term power supply at the price of the 2021 Wyoming wind resource is open-ended over some significant range. Is this accurate?

A. Yes, though I believe defining the limits of the Company's proposal and the scope of its resource needs would help put this in context. The 1,100 MW of wind resources in the 2017 IRP preferred portfolio were projected to have a 41.2 percent capacity factor which equates to an average output of approximately 450 MW. This is comparable to the maximum output of many of the Company's coal and gas units, two of which (Naughton 3 and Cholla 4) are expected to retire in the next several years, with several other retirements expected over the IRP study horizon. So while 1,100 MW of wind is a significant proposal, it is really only an incremental addition to the Company's very substantial portfolio.

The Company's demand for long term power supply is also significantly larger than the 2021 Wyoming wind resource, as the 450 MW of average output represents less than seven percent of the Company's retail load. Much of that output is expected to replace higher cost generating resources, *i.e.*, the Company's coal and gas, particularly in the first several years. But even with the proposed 2021 Wyoming wind resources, the Company's portfolio will continue to serve retail customers primarily with coal and gas generation, as well as market purchases, each of which could be avoided by additional low-cost generating resources. Even with the 2021 Wyoming wind resources, coal generation represents roughly half of the Company's retail load over the next 10 years, while natural gas generation represents roughly 20 percent.

Q. Since you agree that the Company's demand for resources at the price of the 2021 Wyoming wind resources is substantially larger than the proposed size of that project, shouldn't avoided costs reflect that same price, as suggested by the Coalition?[13]

A. The customer indifference standard dictates that avoided cost pricing be neither higher nor lower than the costs the Company would otherwise have incurred. The Schedule 37 pricing for Utah wind QFs proposed in my direct testimony is *higher* under the current Schedule 38 methodology with deferral of 2031 wind resources than it is when 2021 Wyoming wind resources are assumed to be deferred. This analysis assumes that PTC values are captured over the first 10 years 2021 Wyoming wind operations, consistent with reality. As discussed in my direct testimony, on a capacity contribution equivalent basis, each megawatt-hour("MWh") produced by a Utah tracking solar resource would be equivalent to 4.9 MWh from the 2021 Wyoming wind resource, while each MWh produced by a baseload resource would be equivalent to 2.6 MWh from the 2021 Wyoming wind resource.[14] As a result, the lost PTC in the first 10 years equal or exceed the energy and capacity value from solar or biomass QFs, resulting in negative avoided costs. The Company's avoided costs are thus higher than the costs associated with the 2021 Wyoming wind resource, regardless of QF type. This is to be expected, since the

[13] Townsend Direct at 21, lines 455-459.
[14] MacNeil Direct at 16-17, lines 332-338.

2021 Wyoming wind and transmission proposal provides net customer benefits and has an upward limit as a result of transmission limitations.

Q. The Coalition suggests that the capacity cost to ratepayers of a Company-owned asset over the first 15 years of operation is actually greater than a QF based on the avoided cost of that same asset.[15] Is this accurate?

A. No, not in the case of the 2021 Wyoming wind resources, which provide substantial benefits in the form of PTC in the first 10 years of operation that offset much of their capital cost. Further, in years 16-30, customers would continue to receive the benefits associated with the Company-owned asset, while paying significantly reduced costs as a result of depreciation. If the QF signed another contract for years 16-30 and the Company's avoided costs were the same, it would be paid a much higher rate than the cost of the depreciated Company-owned asset. Over a 30-year period, the levelized cost to customers of the Company-owned asset and the contracted resource would be identical.

Q. If the cost to customers over a 30-year life is identical for a Company-owned asset and a contracted resource, why is it necessary to remove PTCs from the levelization calculation?

A. The cost to customers in the example above is only identical if the Company's avoided cost remains the same. However, after a QF's 15-year contract expires, the Company will not be able to procure wind resources that will qualify for PTC, and its avoided costs are expected to be higher. Customers would be forced to pay the QF at the then current avoided cost rate and would lose any PTC benefits not captured in the term of

[15] Townsend Direct at 24, lines 527-530.

the initial contract.

Q. Is there any additional evidence that the proposed wind and transmission resources should not be considered deferrable by QF resources elsewhere on the Company's system?

A. Yes. The capacity contribution associated with the 2021 wind resources in the 2017 IRP preferred portfolio amounts to 174 MW. Since the 2017 IRP was prepared, the Company has executed QF contracts for resources outside of the constrained area of Wyoming with a capacity contribution totaling over 90 MW. On a capacity equivalent basis, this represents over half of the 2021 Wyoming wind resource, or over 500 MW nameplate wind capacity. Yet these acquisitions have had no impact on the Company's plans to pursue the 2021 Wyoming wind resources because even with the additional QFs, the wind and transmission resources remain cost-effective.

UCE RENEWABLE COST FLOOR PROPOSAL

Q. Please describe UCE's proposed renewable cost floor.

A. UCE proposes that the existing Proxy/PDDRR methodology be used to establish capacity payments based on deferrable thermal resources, with a floor on avoided costs based on the cost of renewable resources in the preferred portfolio, after applying adjustments to account for project specific characteristics. The proposed deferral of thermal resources appears to be comparable to what occurs when there are no renewable resources in the preferred portfolio. The second step in UCE's proposal is the application of a price floor whenever any renewable resource is present in the preferred portfolio.

Q. Do you have any concerns with the proposed deferral of thermal resources?

A. Yes. If both solar and thermal resources are present in the preferred portfolio in the deficiency year, a solar QF should be assumed to defer a capacity equivalent amount of the solar resource rather than a capacity equivalent amount of the thermal resource. As previously discussed, replacing a solar resource with another solar resource helps to maintain consistency in the myriad other operational characteristics which contributed to the solar resource being selected for the preferred portfolio. The solar and thermal resources in the preferred portfolio cannot possibly be considered equivalent to each other in all characteristics. Considering a solar QF and a thermal resource to be equivalent runs afoul of the exact same limitations. Calculating an avoided cost rate based on a thermal resource with adjustments to be consistent with the IRP solar resource seems needlessly complicated, particularly when the current adjustments for geographic location and resource operating parameters are captured through a resource's inclusion in the GRID model and its impact on the Company's operations.

As previously discussed, the presence of a resource in the preferred portfolio indicates that it contributes to the least-cost, least-risk portfolio. Analogously, the absence of a resource in the preferred portfolio indicates that lower cost alternatives are available. Further the specific quantity of a resource in the preferred portfolio indicates how much can be added before alternatives result in lower costs.

Q. Do you have any concerns with the renewable price floor in UCE's proposal?

A. Yes. The Company has already proposed that the QFs be eligible to defer the most comparable resources in the preferred portfolio. Under UCE's proposal QFs could receive higher avoided costs based on a deferred thermal resource, even if a more comparable QF was present in the preferred portfolio. Under no circumstances should retail customers pay more as a result of "adjustments" to a mismatched resource than they would have paid for more closely matched resource. This principle should extend not just to resources in the preferred portfolio but also to resources that were evaluated in the IRP but not selected. The absence of unselected resources in the preferred portfolio is evidence that their costs are in excess of avoided costs, so any avoided cost methodology which results in costs in excess of selected or unselected alternatives should be considered faulty. Indeed, the principles of PURPA dictate that avoided costs must not exceed what the Company would have otherwise incurred, and the resource options in the IRP are just that, options the Company can exercise to serve customer load. This implies that the costs of preferred portfolio resources in the IRP should serve as ceiling, not a floor as proposed by UCE, and that the costs of unselected resources could only be considered as a ceiling after adjusting to account for the fact that they were not the lowest cost option.

Q. Is UCE's application of the renewable price floor to only renewable resources reasonable?

A. No. There is no basis for differentiating the avoided costs of a Utah QF which is "renewable" and an identical resource that is non-renewable. Similarly, the capacity and energy value of a resource is unchanged by the Company's receipt of RECs from that resource. As a result, there is no basis for restricting fossil-fueled cogeneration facilities from avoided cost rates based on UCE's renewable price floor. UCE's definition of renewable resources is thus arbitrary with regard to the Company's avoided costs for Utah QFs. The lack of any resource distinction highlights that meaningful operational differences that do impact the Company's avoided costs are being ignored.

Q. UCE claims that deferral of preferred portfolio resources is irrelevant to setting an avoided cost floor.[16] Do you agree?

A. No. The primary output of the Company's IRP process is its preferred portfolio and the intent of the Proxy/PDDRR methodology is to produce a comparable portfolio that removes Company resources that are no longer needed as a result of QF contracts. As a result, the key outcome of the Proxy/PDDRR methodology is the composition of the portfolio that is developed, as it is the foundation upon which the rest of the analysis rests. Indeed the intent of the GRID model is to comprehensively calculate all of the elements of avoided costs other than fixed capacity deferral costs. FERC PURPA regulations, 18 CFR § 292.304(e)(2) state that the following factors "shall, to the extent practicable, be taken into account" when setting avoided cost prices:

i. The ability of the utility to dispatch the qualifying facility;

ii. The expected or demonstrated reliability of the qualifying facility;

iii. The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirements, and sanctions for non-compliance;

iv. The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility's facilities;

v. The usefulness of energy and capacity supplied from a qualifying facility

[16] Dragoon Direct at 11, lines 210-217.

during system emergencies, including its ability to separate its load from its generation;

vi. The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system; and

vii. The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities.

It is unclear how UCE expects to calculate an avoided cost floor that accurately addresses these factors and doesn't use the GRID model.

Q. Please illustrate the shortcomings of UCE's proposal.

A. UCE suggests that if the Company's preferred portfolio includes a wind resource with a levelized cost of $30/MWh, then a QF resource should be worth at least $30/MWh to the Company. If the resource in the preferred portfolio provides benefits of $35/MWh, the QF would also need to provide equivalent benefits to maintain retail customer indifference or else avoided cost would need to be reduced. By ignoring the benefits of preferred portfolio resources, UCE's methodology fails to ensure retail customer indifference.

<u>**SCHEDULE 37 METHODOLOGY**</u>

Q. Please summarize the issues raised by Parties relating to the Company's proposed methodology for Schedule 37 rates.

A. OCS and DPU generally support the Company's proposal to use the Schedule 38 methodology for Schedule 37 rates, but express concerns related to the application of the potential QF queue. The Coalition and UCE each oppose using any potential QFs in the determination of Schedule 37 rates. The Coalition and UCE each recommend that the current Schedule 37 pricing methodology be retained. UCE also proposes adjusting Schedule 37 rates for avoided line losses. I respond to Parties proposals on each of these issues in the following sections. The Coalition also proposes the creation of separate renewable and non-renewable pricing options, which I have previously addressed.

SCHEDULE 37 QF QUEUE

Q. Please summarize Parties' proposals related to the QF queue for Schedule 37 rates.

A. DPU proposes using the midpoint of the potential QF queue to set Schedule 37 rates for this proceeding and reevaluating this assumption in future years.[17] OCS agrees that the use of the potential QF queue for Schedule 37 rates is appropriate, but that placement at the end of the queue may not produce the most reasonable results.[18] The Coalition and UCE both propose that Schedule 37 rates not incorporate any potential QFs.[19]

Q. What is the Company's basic principle with regard to incorporating the QF queue in Schedule 37 rates?

A. The Company, and by extension its retail customers, should not pay more than its avoided costs for Schedule 37 resources. As discussed in my direct testimony, avoided cost prices are highest for the first QF in the queue and are lower for QFs later in the queue.[20] Because it is highly likely that the Company will acquire additional resources during the effective period of the Schedule 37 rates, either as QFs or through RFPs, an

[17] Abdulle Direct at 9, lines 162-166.
[18] Murray Direct at 8-9, lines 125-127.
[19] Bowman Direct at 7, lines 109-110.
[20] MacNeil Direct at 34, lines 704-711.

accurate forecast of avoided costs must account for the impact of those resources.

Q. Did the Company adjust its Schedule 37 QF queue proposal in its August 17, 2017 consolidated direct filing, relative to its original May 30, 2017 filing in Docket No. 17-035-T07?

A. Yes. The Company's May 30, 2017 filing calculated avoided costs using the entire QF queue at that time, including potential resources totaling 3,968 MW of nameplate capacity. The Company's August 17, 2017 filing in Docket No. 17-035-37 used the same position in the QF queue as the May filing but with updates for signed contracts and projects that had dropped out, resulting in prior queued resources totaling 1,436 MW of nameplate capacity. As a result, the August 17, 2017 filing represented a queue position of roughly 36 percent.

Q. Please summarize the impact of the potential QF queue on Schedule 37 rates.

A. Figure 1R below compares the current Schedule 37 rates based on the existing thermal proxy methodology and the resource-specific rates based on the Schedule 38 methodology using three queue positions: the entire queue as included in the May 30, 2017 filing, the reduced queue included in the August 17, 2017 filing, and the queue of signed contracts as of August 2017. Prices for fixed tilt solar are not shown as they follow a pattern similar to that of tracking solar. Figures 2R, 3R, and 4R below provide a year by year comparison of the rates for baseload, wind, and tracking solar resources under the various methodologies discussed in testimony.

Figure 1R: Summary of Schedule 37 Proposals

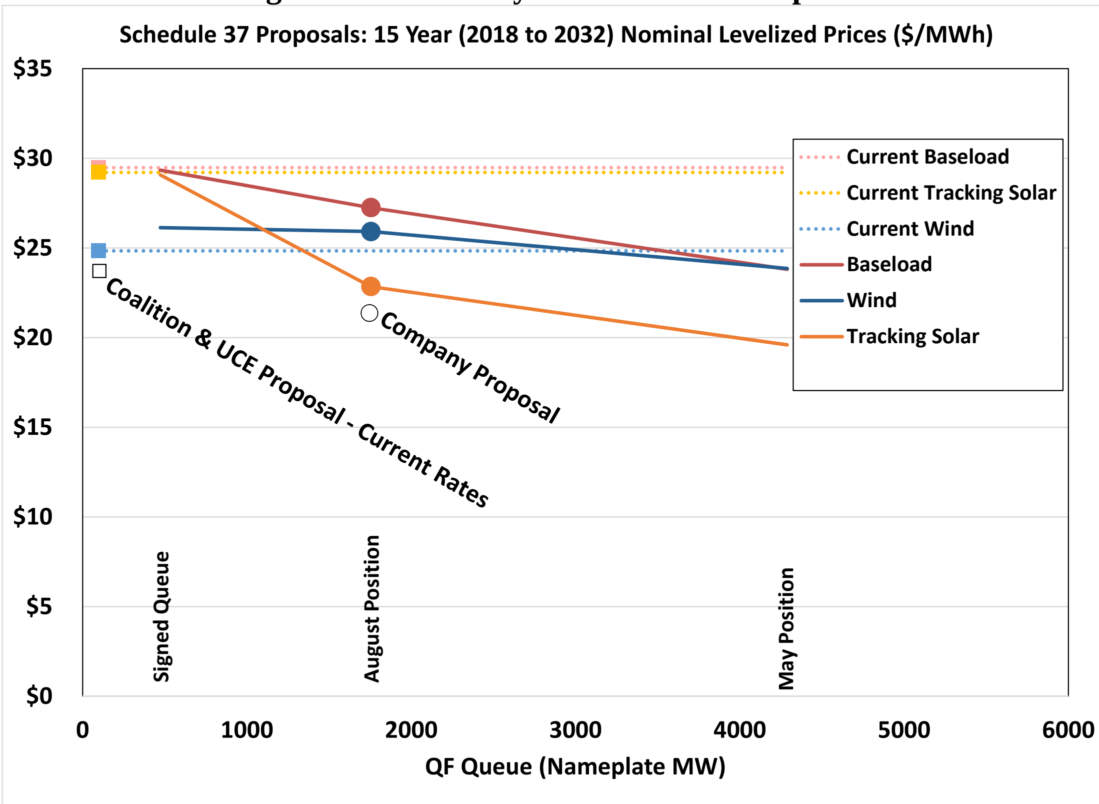
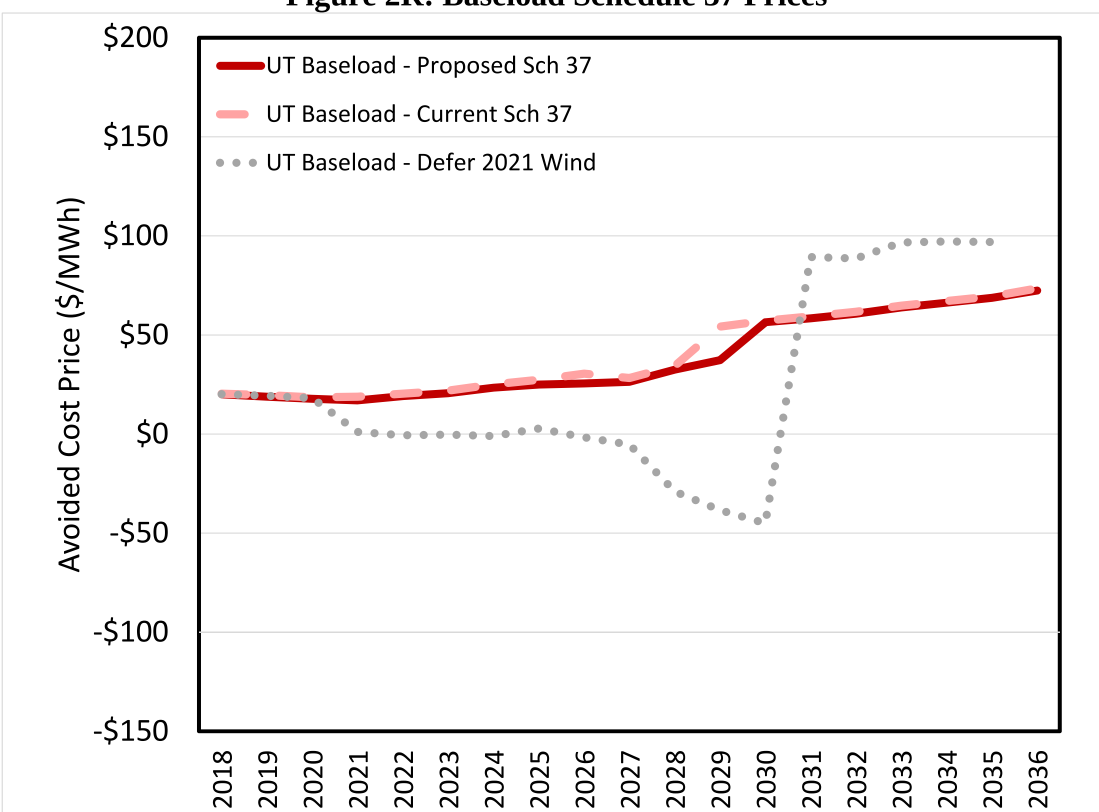


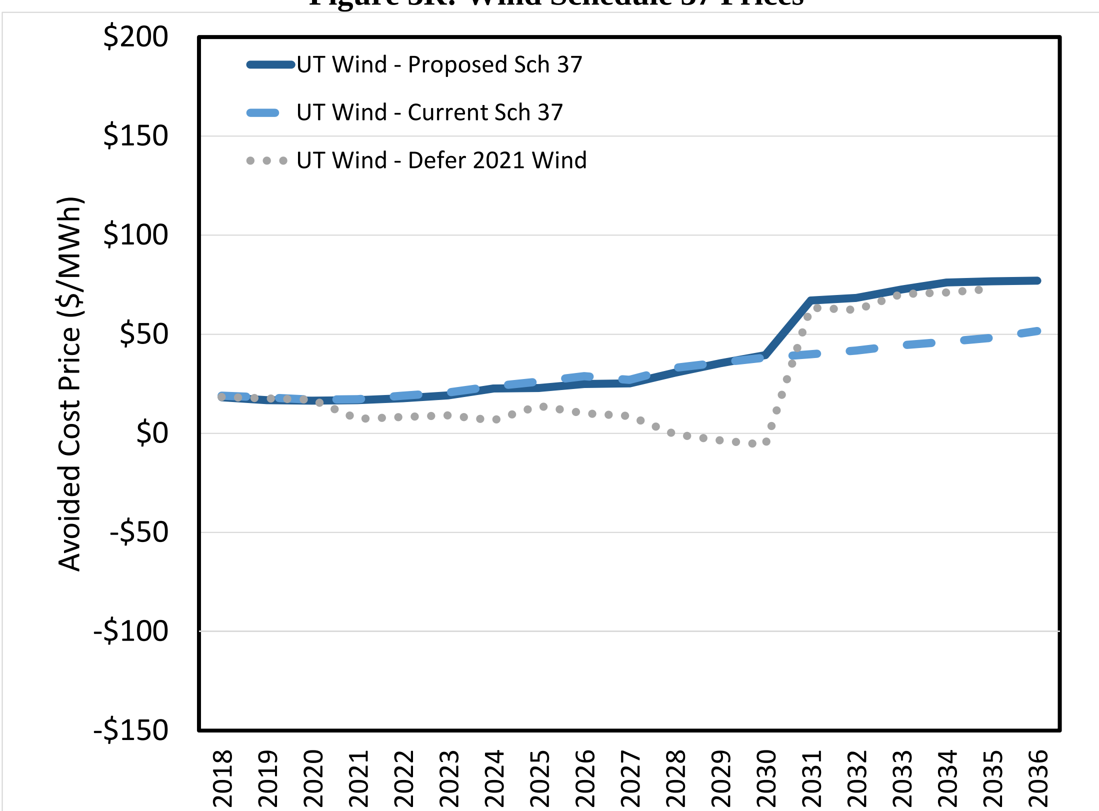
Figure 2R: Baseload Schedule 37 Prices



Q. What does Figure 2R show with regard to the proposed prices for baseload resources?

A. The proposed prices for baseload resources are very similar to those under the current Schedule 37 methodology. This is to be expected since the resource used to set to deficiency period rates is the same in both cases. The slight difference in 2029 is due to a one year delay in capacity payments as a result of the QF queue. The prices based on deferral of 2021 Wyoming wind resources are well below the proposed prices until 2031 when PTCs expire, then well above thereafter, and are not a reasonable representation of the Company's avoided costs in either period.

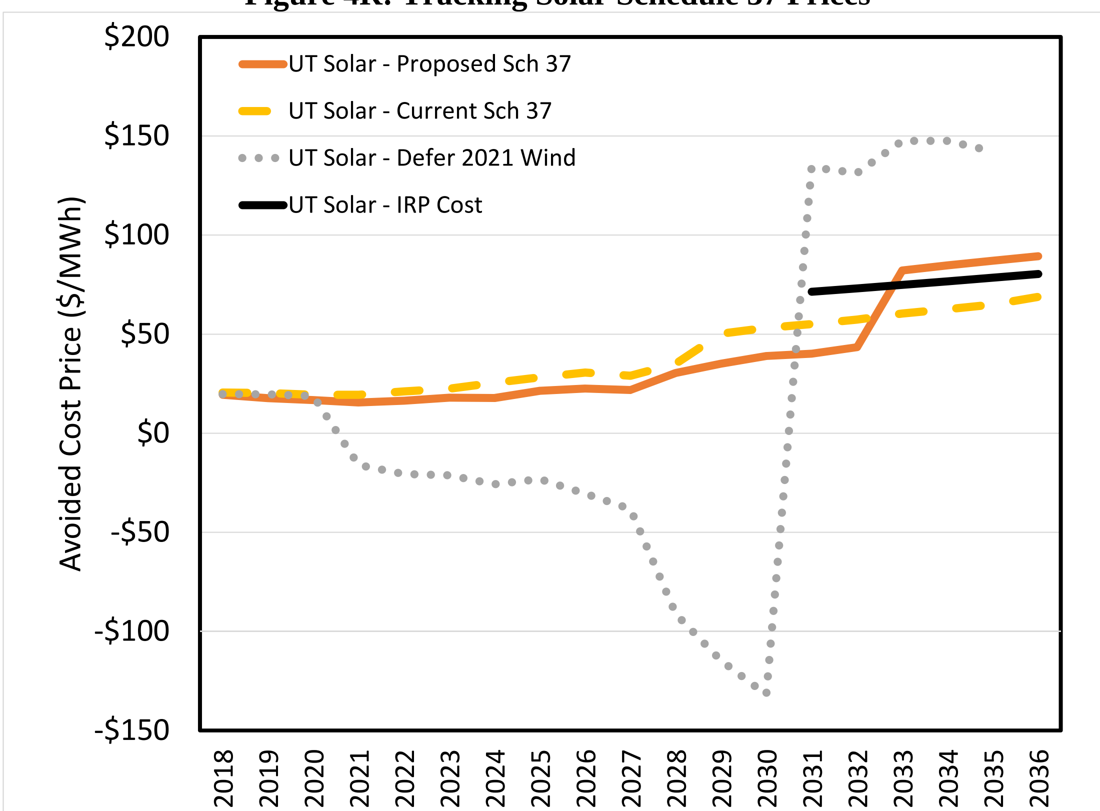
Figure 3R: Wind Schedule 37 Prices



Q. What does Figure 3R show with regard to the proposed prices for wind resources?

A. The proposed prices for wind resources are also comparable to those under the current Schedule 37 methodology. While the wind shape used is different from the baseload resource used in the current Schedule methodology, wind has relatively more output in the winter and during the night, both periods with less solar generation. As a result, the large number of solar resources in the potential QF queue have a relatively small impact on the wind resource's avoided cost. Starting in 2031, the proposed prices include deferral of a wind resource from the 2017 IRP preferred portfolio. In contrast, the prices based on deferral of 2021 Wyoming wind resources are well below the proposed prices until 2031 when PTCs expire, and then comparable thereafter. This indicates that there are higher cost resources to be avoided than the 2021 Wyoming wind resource.

Figure 4R: Tracking Solar Schedule 37 Prices



Q. What does Figure 4R show with regard to the proposed prices for solar resources?

A. The proposed prices for solar resources are somewhat lower than those under the current Schedule 37 methodology during the sufficiency period. Because solar resources have daily and seasonal peak output at roughly the same time, the large number of solar resources already on the Company's system and in the potential QF queue have a significant impact on avoided costs for solar. Once the deficiency period is reached in 2033, the proposed prices include deferral of solar resources from the 2017 IRP preferred portfolio and prices are higher than under the current methodology. Prices in 2033 are also slightly higher than the cost of Utah solar resources in the 2017 IRP. In contrast, the prices based on deferral of 2021 Wyoming wind resources are well below zero until 2031 when PTCs expire, and then well above thereafter. Negative avoided costs during the sufficiency period are not reasonable when the Company has coal and natural gas resources available to be backed down, nor are avoided costs in deficiency period that are twice the forecasted cost of solar resources in the IRP preferred portfolio.

Q. Have there been any other recent changes which should be considered to determine a reasonable queue position for setting Schedule 37 rates?

A. Yes. First, since the pricing was prepared for the August 17, 2017 filing, the Company has executed a contract with an additional solar QF developer with 17.6 MW nameplate capacity. Second, in the August 17, 2017 filing Clenera's Faraday and Goshen Valley projects had been removed from the potential QF queue since they were unable to provide all of the information necessary to continue contract negotiations as required under the Schedule 38 procedures. Clenera's projects total over 1,000 MW, in excess of the total solar resource additions in the 2017 IRP preferred portfolio, thus Clenera has a significant impact on the Company's deficiency period and avoided costs. Clenera has requested in Docket No. 17-035-52 that its queue position for these QFs be reinstated pending completion of interconnection studies. Suspension of the

Schedule 38 procedures for this proposal has been supported by DPU, which specifies that the indicative pricing previously provided to Clenera should remain valid pending completion of interconnection studies and additional time for PPA negotiations. To the extent the Commission rules that Company must keep these prices available for Clenera, the capacity and energy these projects provide should be accounted for in avoided cost rates for other QFs, including in Schedule 37.

SCHEDULE 37 PROXY METHOD

Q. Does the Coalition or UCE provide any evidence that the GRID/Proxy methodology used in the current Schedule 37 rates produces a more accurate forecast of avoided costs than the Proxy/PDDRR methodology used for Schedule 38?

A. No.

Q. Do you have specific examples of how the current Schedule 37 methodology is less accurate than the current Schedule 38 methodology?

A. Yes. First, during the sufficiency period the current GRID/Proxy methodology calculates a single monthly avoided cost based on the generation of a baseload resource. This does not accurately reflect the generation profiles of wind and solar resources. Because the existing solar resources in the Company's portfolio already avoid the highest cost resources during the day, avoided costs for new solar resources delivering at the same times are necessarily reduced. The baseload resource used to determine the single monthly avoided cost value in GRID/Proxy reflects an equal weighting of day and night that is inappropriate for solar.

Second, during the deficiency period the current Schedule 37 methodology calculates avoided costs based on the fixed and variable costs of a thermal proxy. This methodology fails to account for the benefits associated with dispatching the thermal resource up or down in response to resource needs and market prices. For instance during the spring run-off period, a CCCT may be taken offline to allow for lower cost market purchases. The current Schedule 37 methodology assumes that QF output during the spring will have value equal to the variable cost of the thermal proxy–even if that resource was expected to be offline during that period.

Q. How do you respond to the Coalition's justification for maintaining the current GRID/Proxy methodology because Schedule 37 rates are "already too low"?[21]

A. As I note in my direct testimony, the proposed rates for wind resources are higher than those currently reflected in Schedule 37.[22] Likewise, during the deficiency period, the proposed rates for solar are higher while rates for baseload resources are comparable to those under the current methodology. Obviously, the Company's proposal would not inherently reduce avoided costs under Schedule 37.

Q. The Coalition implies that the Company's "major new-build cycle" contradicts its proposal to reduce avoided cost rates. Do significant resource acquisitions indicate avoided costs should be higher?

A. No. The Company's proposed wind resources are expected to contribute to lower customer rates, implying that the avoided costs associated with them are lower than other alternatives. This is different from primarily demand-driven resources, which are generally more expensive than the Company's existing portfolio, indicating avoided costs are relatively high.

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[21] Lowe Direct at 8, lines 94-96.
[22] MacNeil Direct at 35, lines 730-731.

AVOIDED LINE LOSSES

Q. How do you respond to UCE's proposal that rates for small QFs connected to the distribution system be adjusted to account for avoided line losses?[23]

A. Merely being connected to the distribution system does not ensure that a new resource will allow line losses to be avoided. To the extent the addition of a resource results in a surplus of resources, those resources would need to be exported to another area– potentially resulting in more losses than would occur had the same resource been interconnected to the transmission system directly.

Q. Do you have a suggestion for addressing UCE's proposal?

A. This issue would be better addressed in the "Export Credit Proceeding" to be initiated as a result of the settlement stipulation dealing with net metering in Docket No. 14-035-114. A comprehensive consideration of the generation impacts of resources delivering at various voltages and locations is appropriate to the determination of accurate export credits.

Q. Does this conclude your rebuttal testimony?

A. Yes.

[23] Bowman Direct at 7, lines 112-116.

CERTIFICATE OF SERVICE

Docket Nos. 17-035-T07 and 17-035-37

I hereby certify that on October 31, 2017, a true and correct copy of the foregoing was served by electronic mail and overnight delivery to the following:

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