ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

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August 8, 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. 14-035-114 - In the Matter of the Investigation of the Costs and Benefits of PacifiCorp's Net Metering Program
Surrebuttal Filing

Pursuant to the Order issued by the Public Service Commission of Utah ("Commission") in this docket on November 18, 2016, Rocky Mountain Power hereby submits for filing its Surrebuttal Written Testimony. The filing consists of the surrebuttal testimony and exhibits of three witnesses.

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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Sincerely,

Jeffrey K. Larsen
Vice President, Regulation

CC: Service List - Docket No. 14-035-114

Rocky Mountain Power
Docket No. 14-035-114
Witness: Gary W. Hoogeveen

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Surrebuttal Testimony of Gary W. Hoogeveen

August 2017

Q. Are you the same Gary W. Hoogeveen who presented direct and rebuttal testimony in this proceeding?

A. Yes I am.

Q. What is the purpose of your surrebuttal testimony?

A. I respond to the Joint Proposal of the Office of Consumer Services ("OCS") and Division of Public Utilities ("DPU") that was appended to the rebuttal testimony of OCS witness Michelle Beck as Attachment 1 and DPU witness Dr. Artie Powell as Exhibit 1.1R.

Q. What is the Company's response to the Joint Proposal?

A. While the Joint Proposal is different in many respects from the Company's recommendation in its original filing, the structure of the proposal for a new program for customer with private generation addresses many of the Company's concerns with the current NEM structure. As noted in the rebuttal testimonies of OCS witness Ms. Beck, and DPU witness Dr. Powell,[1] the cost of service studies demonstrate that the costs of NEM outweigh the benefits of the program. The Company's filing and the Joint Proposal both recognize the cost shift to non-NEM customers that occurs when NEM customers avoid paying the full costs of their service and are paid retail rates for the energy they produce, which far exceeds the value of that energy. Both of these aspects of the current NEM structure shift costs that are borne by our non-NEM customers. The Company's proposal and the Joint Proposal each attempt to remedy these problems, albeit in different ways. While the proposed structure in the Joint Proposal is different

[1] *See, e.g.*, DPU witness Artie Powell Direct Testimony, ll. 35-37; Powell Rebuttal Testimony, ll. 362; OCS Witness Michele Beck Direct Testimony, ll. 68-71; Beck Rebuttal Testimony, ll. 26-29.

than what is filed in the Company's application, we agree that it is an acceptable structure to address the inherent and ever-increasing cost shift in the current NEM program. However, if the Commission approves the proposed structure, careful consideration should be given to each of the elements and the costs that will be borne by customers that do not elect to generate their own electricity. The way to achieve that objective is to ensure that, even if there is a short transition from the existing structure, the ultimate result should be that private generation customers are paid an amount that is based on an avoided cost rate for the energy they put back into the system.

Q. Please provide some examples of how the Joint Proposal differs from the Company's filing.

A. The Joint Proposal differs in both structure and rate design from the Company's filing. I think it is most helpful to examine the structure of the Joint Proposal separately from the numeric values of the Joint Proposal's rate design. Turning first to structure, where the Company's filing proposes to close Schedule 136 and create a new Schedule 5 that would include all NEM customers in a separate customer class, the Joint Proposal caps the current net metering schedule at the penetration level effective December 31, 2017, and thereafter proposes to create subclasses of grandfathered and transition class customers. In addition, the Joint Proposal recognizes that the exported power is not equivalent to the retail rate as under the current rate design and seeks to address future cost shifting by eliminating monthly kilowatt-hour netting and proposing a future docket to determine the proper rate for exported power, whereas the Company's proposal makes modifications under the NEM construct to address all issues in this docket. The Company's proposal consists of two rate options: a three-part rate including a customer charge, on-peak demand charge, and reduced volumetric rate and a two-part rate with a customer charge and time-of-use energy. The Joint Proposal keeps future post-NEM customers in the same customer class as all residential customers and simply lowers the export rate that future post-NEM customers are paid for their excess generation. Finally, while the Company indicated support for modest grandfathering of existing NEM customers, the Joint Proposal expressly identifies grandfathering periods for existing customers as well as proposes a new program with a transition period and transition rate for new customers with private generation. Company witness Joelle R. Steward's rebuttal testimony more fully described the differences between the two structures.

Q. Does the Company agree with the new program structure as described in the Joint Proposal?

A. Partially. To be clear, the Company still maintains that the rates it has proposed are the more accurate rate structure for NEM customers. Again, with reference to the more detailed discussion in Ms. Steward's testimony, if certain modifications are made to the Joint Proposal it would address many of the concerns the Company has with the current NEM program. Therefore, if the Commission determines that the structure of the Joint Proposal is an acceptable or preferable alternative, or even because of the desirability for consensus, the Company supports that framework, provided the values in the Joint Proposal are modified for the transition period. We recall the words of the Commission in its November 10, 2015 Order in this docket when it stated "we weigh heavily the fact that unanimity exists among the Division, the Office and PacifiCorp that the established cost of service models provide the proper platform for conducting the cost benefit analysis"[2]. The Company supports the new program structure in the Joint Proposal and views it as a fair and balanced alternative for both NEM and non-NEM customers, provided that the values in the proposal are carefully weighed and applied.

Q. What are the specific elements that the Company has concerns with?

A. The Joint Proposal includes ranges of time for grandfathering existing NEM customers and a transition period for the new program customers before the Commission's final compensation rate becomes applicable to all new private generation customers. In addition, the Joint Proposal includes a small reduction in the export rate for the transition customers, and proposes that this rate apply until the above-referenced grandfathering and transition periods expire.

Q. Does the Company generally agree with the transition periods, grandfathering timetables, and transition export rates proposed in the Joint Proposal?

A. No. While the Company supports the proposed structure for the new program in the Joint Proposal, the Company is concerned with the specific time periods and rates because they do not fully resolve the issues they are intended to address and lock-in risk to other customers more than under the current NEM program. Fundamentally, the Company is not opposed to grandfathering or a reduction in the export rate. Indeed, the Company's November 2016 compliance filing indicated that the Company is not opposed to the Commission considering a short and reasonable grandfathering period if the Commission deems it to be in the best interests of our customers. However, the

[2] Docket No. 14-035-114, Order at p. 6 (November 10, 2015).

Company has concerns with the length of time proposed by the parties for grandfathering and transitioning, as well as the level of the proposed export rate.

Q. What are the Company's specific concerns with the proposed transition export rate?

A. As described in the rebuttal testimony of Michele Beck, the Joint Proposal is based on the assumption that existing NEM customers would receive the full retail rate for their exports for a period of 12-17 years. It also recommends that transition private generation customers would receive 95 percent of the average retail rate for a period of 10-15 years. While this figure is a slightly lower compensation amount for NEM customers' exported generation under the current NEM program, rate is proposed to be locked in without further Commission review over a relatively long duration. For perspective, and as shown in the surrebuttal testimony of Robert M. Meredith, for every one cent above cost-based rates that the Company must pay for transition customers' excess generation, there is an annual cost shift of approximately $1 million to non-NEM customers. Spread over 12-17 years, this results in a cost shift of approximately $15 million to $22 million for each additional cent per kilowatt hour that the export credit price is inflated beyond a comparable cost. The basis for considering a transition period is to provide the industry and customers considering purchasing systems under the current structure some form of gradualism away from the current net metering program. Recognizing that as an issue the Commission will wrestle with, the Company is less persuaded that *future* private generation customers should be given a relatively long transition period with a locked-in export rate. Since both the OCS and DPU acknowledge that the current structure unjustifiably shifts costs from NEM customers to non-NEM customers, a transition period of any length seems unwarranted. In addition, the grandfathering period for existing NEM customers should be modest, and certainly should be based from the date the NEM customer interconnected with our system—not from the date of the Commission's order. While the Company is mindful that the Commission will consider the impact of a rate change on private generation customers, the Company maintains that the purpose of this docket is to weigh the quantifiable costs and benefits of private generation and to implement a new and proper rate structure that would balance those costs and benefits based upon the viewpoint of the *non-NEM customer*. This can and should be done to remove cost shifting over a much shorter period of time.

Hence, while the *structure* proposed by the OCS and DPU could accomplish that goal, the *level* of grandfathering and the *level* of transition export rate proposed appear to be balanced more heavily toward the interests of current and future private generation customers, not the other customers who are subsidizing them. The focus on the impact to private generation customers, to the exclusion of other customers, conflicts with the general intent of the Commission's prior order that stated:

> As a matter of law we conclude Subsection One requires the Commission to consider costs and benefits that accrue to the utility *or its non-net metering customers* in their capacity as ratepayers of the utility. (July 1, 2015 Order at p. 15 (emphasis added)).

Q. If the Commission adopts the new program structure proposed by the Joint Proposal, does the Company have transition export rate values that the Company believes would be reasonable under the circumstances?

A. Yes. Taken strictly from the viewpoint of other customers, the Company continues to maintain, as it has throughout this proceeding, that the appropriate export rate for private generation customers' excess generation should be the avoided cost rate, consistent with the rate the Company is required to pay for energy from other independent producers. Any rate in excess of avoided cost will represent an expense borne by other customers. All of the purported socio-economic and environmental benefits of rooftop solar generation also exist—to the extent they exist at all—with large-scale renewable energy developers to whom the Company pays only the avoided cost rate for production.

That said, to the extent the Commission is unwilling to adopt avoided cost as the proper rate for exported generation during the pendency of a new proceeding to develop a methodology for setting the export credit, the surrebuttal testimony of Mr. Meredith contains calculations showing the amount of cost shift to other customers based upon the values in the Joint Proposal, for both the high and low end of grandfathering and transition period included in the Joint Proposal as well based on avoided cost and the mid-point between the retail rate and avoided cost, which was originally proposed by the DPU in direct testimony[3]. For additional perspective on the impact of the fixed term for the transition period, the scenario shows that a five-year transition compared to a 10-year transition period could reduce cost shifting by 12 percent. Utilizing these tables, the Commission is able to make an educated and balanced determination of the appropriate transition export rate and term and appropriate length of grandfathering of NEM customers to implement if the

[3] Powell Direct Testimony, ll. 482-484.

Commission determines that the structure outlined in the Joint Proposal is in the best interests of the Company's Utah customers.

Q. Does that conclude your surrebuttal testimony?

A. Yes.

Rocky Mountain Power
Docket No. 14-035-114
Witness: Joelle R. Steward

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Surrebuttal Testimony of Joelle R. Steward

August 2017

Q. Are you the same Joelle R. Steward who presented direct and rebuttal testimony in this proceeding?

A. Yes I am.

Purpose of Rebuttal Testimony

Q. What is the purpose of your surrebuttal testimony?

A. My surrebuttal testimony responds to the rebuttal testimony of Utah Clean Energy ("UCE") witness Tim Woolf; Vote Solar witness Dr. David DeRamus; Vivint Solar witness Richard Collins; and Western Resource Advocates ("WRA") witness Steven Michel filed July 25, 2017. I also respond to certain aspects of the Joint Proposal submitted by Dr. Artie Powell for the Division of Public Utilities ("DPU") and Michele Beck for the Office of Consumer Services ("OCS"). A lack of response to particular statements made in rebuttal by parties should not be interpreted to mean the Company agrees with that statement; rather, many statements in rebuttal testimony were reiterations of arguments the Company addressed in its rebuttal testimony and, thus, the Company will not repeat those arguments here.

Response to Joint Proposal by DPU and OCS

Q. Do you have comments on the Joint Proposal by the DPU and OCS regarding the proposed structure for the transition away from net metering ("NEM")?[1]

A. Yes. My comments supplement the general comments of Company witness Gary W. Hoogeveen and economic analysis of Company witness Robert M. Meredith in their surrebuttal testimonies regarding the Joint Proposal. Specifically, I will address the Joint Proposal's specific recommendations regarding (1) fixed rates for compensating

[1] DPU witness Dr. Artie Powell DPU, rebuttal testimony, Exhibit 1.1R, and OCS witness Michele Beck, rebuttal testimony, Attachment 1 ("Joint Proposal").

exports during the transition period, (2) allowing transition customers to remain in "their then-existing appropriate rate class" through the transition period, and (3) the first phase of the compensation proceeding.

Q. Do you have concerns with the specific recommended fixed rates to compensate for exports during the Joint Proposal's transition period?

A. Yes. Page 3 of the Joint Proposal contains the proposed rates for each customer class for exported energy for transition customers. Under the Joint Proposal, these rates would be fixed for the transition period customers for 10 to 15 years. Footnote 2 on page 3 explains that these rates were calculated at 95 percent of the current average retail rate for each rate schedule, based on my workpapers in this filing for the residential rate and from a data response to the OCS from the Company for the non-residential customers.

To clarify, however, the residential workpapers used for the calculation were based on calendar year 2015 results, which was used for the NEM analysis, not the last general rate case. Accordingly, the starting point for the 95 percent reflects actual results in 2015, not the rates last approved by the Commission. While the Company used calendar year 2015 for the cost of service analysis in this filing to use the load research data that was collected in 2015, the proposed rates were developed based on a reconciliation to the rates approved by the Commission in the last general rate case.[2] A calculation of 95 percent from the average residential energy rate (excluding customer charge revenue) as approved by the Commission in the last general rate case would

[2] *See* Direct Testimony of Joelle Steward, ll. 293-303.

result in an export rate of 9.67 cents/kWh rather than 9.79 cents/kWh shown in the Joint Proposal.

The proposed non-residential export rates in the Joint Proposal reflect an apparent misunderstanding as they would result in a value that far exceeds the current value received by non-residential customers on NEM. I doubt that was the intention by the DPU and OCS in the Joint Proposal. The OCS data request that was relied on requested the average retail rate for each rate schedule, which, without context, the Company interpreted as all rate schedule revenue divided by kilowatt-hours. However, under NEM, the netting within the billing month for exported power is based on only kilowatt-hours, so the monthly value is just the average *energy* rates. In other words, the monthly netting does not include value from monthly customer and demand charges that were reflected in the average retail rate provided in response to the OCS data request. Currently for large non-residential customers, only exported energy that exceeds the monthly netted kWh is priced at compensation rates in Schedule 135, which includes three options of excess compensation rates: two options based on avoided costs and one option for the average retail rate.[3] If the average retail rate were to be provided for all exported energy from non-residential customers, not just the exported energy that exceeds the monthly netted kWh, it would produce a windfall to these customers. Table 1 below shows the average *energy* rates (*i.e.*, revenue from kilowatt-hour charges divided by kilowatt-hours) from the last general rate case for each rate schedule, and what it would be at 95 percent, as contemplated in the Joint Proposal.

[3] The Company's request in this proceeding is to eliminate the option for average retail rate for large non-residential customers on NEM. *See* Steward Direct Testimony, ll. 606-647.

Table 1.

Schedule	Avg. Energy Rate (cents/kWh) 100%	95%
Res 1,2,3	10.18	9.67
6	3.65	3.46
6A	7.19	6.83
6B	3.64	3.46
8	3.75	3.57
10	6.04	5.74
23	8.83	8.39

Q. Do you have other recommendations related to the export credit?

A. Yes. I continue to recommend that the transition rate be consistent with what the Commission has already determined for avoided cost purchases as well as the ratemaking treatment of the export credit discussed in my rebuttal testimony.[4] The proposed treatment continues to be applicable under the Joint Proposal. In short, the Company recommends that, if the Commission approves a post-NEM transition program and export rate, the Company be allowed to defer and recover the annual costs of paying the export rates to customers through the Energy Balancing Account, or other similar deferral mechanism or approach. In addition, the Company recommends that the bill credit for the export power be applied against only the volumetric-based charges on the customer's bill, not the fixed customer charge or minimum bills. Lastly, I support the Joint Proposal provision to carryover any excess bill credits into subsequent billing periods until an annual expiration period, such as March, with expiring credits to be donated to the low income program. This provision provides an economic incentive to customers to right-size their facilities.

[4] Steward Rebuttal Testimony, ll. 661-671, 672-691.

Q. What is your comment in response to the Joint Proposal provision that transition customers "remain in their then-existing appropriate rate class?"[5]

A. While the Joint Proposal recognizes that different rate designs could be adopted by the Commission in any future rate case,[6] it seemingly prohibits the ability of the Commission to consider changes in rate classes that could impact these customers in the future. Different rate classes could be developed for a number of reasons in the future. Constraining the ability of the Company or any stakeholder to present evidence that could support modifications in rate classes in the future is a constraint on the ability of the Commission to fulfill its duties in ensuring rates are in the public interest. No other customer type currently has this pre-determined certainty, therefore we encourage the Commission to not pre-determine in this proceeding as to what future evidence could support.

Q. What are your comments on the Joint Proposal's recommendations on pages 4 and 5 on the compensation proceeding parameters?

A. While the Company generally supports the parameters in the Joint Proposal, I am concerned that the first phase is proposed to be comprised of just data collection and take approximately one year. For one, it is not clear what data collection is necessary. While I would not oppose a workshop or technical conference to discuss data, the proceeding should not be delayed pending data collection. Two, the proceeding should be initiated with discussions on methodologies for the calculation of the elements for consideration in setting the export rate. The methodologies will determine what data needs to be collected.

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[5] Joint Proposal, p. 3.

[6] *Id.*

Response to Rebuttal of Utah Clean Energy witness Tim Woolf

Q. For the most part, Mr. Woolf reiterates many of the same arguments made by UCE in direct testimony. For instance, Mr. Woolf states that demand charges are "especially difficult for residential and small commercial and industrial customers to manage and understand."[7] How do you respond?

A. UCE fails to provide any evidence to support Mr. Woolf's conclusion. While demand charges for residential customers are not yet widespread, it is premature to argue these customers cannot manage or understand them. As I noted in my rebuttal, there is evidence to the contrary from a study done by the Arizona Public Service Company.[8] Furthermore, UCE's argument fails to acknowledge that customers installing private generation are making a sophisticated choice to support their own electricity needs. Accordingly, these customers should be able to take the next step in understanding price signals that will encourage them to minimize costs to the utility system.

Q. Next, Mr. Woolf reiterates UCE's argument that there should not be a separate class for distributed generation customers.[9] What is your observation on his arguments?

A. He states that it "would be premature for the Commission to create a separate rate class for distributed solar customers without first addressing these important policy questions."[10] The important policy question he identifies is whether it is "practical or sustainable to create a new class for each new type of technology that customers install behind the meter," such as deep energy efficiency retrofits, electric vehicles, or

[7] UCE witness Tim Woolf, Rebuttal Testimony, ll. 127-9.
[8] Steward Rebuttal Testimony, ll. 326-32.
[9] Woolf Rebuttal Testimony, ll. 131-181.
[10] *Id.* at ll. 178-9.

storage.[11] While I believe it is important and necessary to consider current rate structures and potentially rate classes for evolving technology, the facts of the matter are that (1) the Commission decision in this proceeding is narrowly related to only NEM and the evidence in this proceeding; it is not a pre-judgment on other changes in technology, and (2) NEM is not just a change in behind the meter technology but is a compensation method for exporting energy. Accordingly, implications from other changes in technology should not be a reason to delay addressing NEM now.

Q. Mr. Woolf disagrees with the OCS that netting should be done on an hourly or more frequent basis than monthly.[12] Do you agree with his arguments?

A. No. Mr. Woolf cites the ability of vendors to market distributed generation as the main problem. But this ignores that continuing as is under NEM will not develop a sustainable path forward. The new model for distributed generation to separate export compensation from retail rates is the appropriate path forward to properly evaluate the service and provide more up-to-date and transparent signals on the value of exported energy. It is better to send correct signals now that will allow for innovation and education rather than perpetuate the current structure at an on-going cost to other customers.

Q. UCE agrees a new proceeding should be opened to investigate new credits for excess generation, but proposes an alternative transition plan.[13] Do you agree with UCE's transition plan?

A. No. UCE's proposal ties any changes in the export credit to general rate cases and sets

[11] *Id.* at ll. 174-7.
[12] *Id.* at ll. 213-23.
[13] *Id.* at ll. 245-8, 313-53.

new tranches of distributed generation customers to periods between general rate cases. Energy purchase costs such as an export credit, however, do not need and should not be tied to general rate cases. There is a viable market for energy and this rate should be set and adjusted consistent with that market to ensure other customers are not harmed. The Commission does not currently tie other must-purchase obligation rates to general rate cases. Nonetheless, the subject of how frequently the export rate should be set and for how long should be a subject in the next proceeding.

Response to Rebuttal of Vivint Solar witness Richard Collins

Q. Mr. Collins argues that a rate design that has demand charges in "(j)ust one brief period when several appliances are being used along with air conditioning will lead to an unreasonably high electric bill" and that it "does not encourage conservation due to the fact that the energy charge of the three part tariff is significantly lower."[14] Do you agree?

A. No. For one, the Company's proposed Schedule 5 on-peak kilowatt charge is based upon an hour interval. As shown in Exhibit RMP___(JRS-5) to my direct testimony, even several minutes of very high appliance usage gets averaged out over the hourly period for a lower kilowatt reading. Certainly, it will be important for proper customer education to accompany any inclusion of demand charges into residential customer rates, but Mr. Collins' exaggerations about customer bill impacts are unfounded. Moreover, this contradicts Mr. Collins' own concern about encouraging energy efficiency. A demand signal encourages customers to reduce, or at least stagger their appliance use during the peak period, which is precisely the signal that reduces costs

[14] Vivint Solar witness Richard Collins Rebuttal Testimony, ll. 158-60 and 179-80.

on the system. It is incorrect to merely look at the energy charge as the only encouragement for conservation signals. Rates that include demand charges still encourage energy efficiency because many conservation measures reduce both kilowatt hour and peak kilowatt consumption. This is evidenced by the presence of substantial demand-side management savings that are achieved by non-residential customers despite those customers being subject to rate designs that include demand charges.[15]

Q. Mr. Collins states that "there are inequities in the current structure of residential rates" and that the "NEM program actually provides a remedy for this subsidy."[16] Do you agree?

A. As I noted in my rebuttal testimony, I agree that there are problems with the current residential rate structure.[17] This present structure for residential rates in concert with the NEM program is largely what has created the need for the Company's filing in this proceeding to protect non-participating customers from cost shifting. The average monthly full requirements energy usage for a residential NEM customer is 977 kilowatt hours per month and the average private generation produced is 534 kilowatt hours per month or about 55 percent of full requirements usage. Residential NEM customers on average are therefore able to exploit and exacerbate the inequities that exist in the residential rate structure by substantially reducing their contribution towards fixed cost recovery while still relying upon the grid to serve them.

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[15] *See* Rocky Mountain Power's Utah Energy Efficiency and Peak Reduction Annual Report, Issued May 15, 2017 at p. 7.

[16] Collins Rebuttal Testimony, ll. 348-55.

[17] Steward Rebuttal Testimony, ll. 170-183.

Q. Mr. Collins states that "as an economist, I believe that when evaluating a program one must look at efficiency first and equity second."[18] With its statutorily obligated evaluation of the costs and benefits of the NEM program and consequent charge, credit, or ratemaking structure, is the Commission faced with a dilemma of choosing between the two conflicting goals of efficiency and equity?

A. No. Mr. Collins seems to imply these two goals are mutually exclusive and that an outcome that favors equity will harm efficiency and conversely one that promotes efficiency will be inequitable. I disagree. Rates that equitably reflect costs will encourage efficient customer behavior. It is neither efficient nor equitable to provide bill savings to residential NEM customers at a price that artificially inflates the value of private generation.

Response to Rebuttal of Western Resource Advocate witness Steve Michel

Q. WRA proposes modification to the proposals of the DPU and OCS in their direct testimonies.[19] Do you agree with the proposed modifications?

A. Not entirely. I appreciate the creative approach and recognition by WRA that it is appropriate and timely to move to an alternative to NEM. However, the Company has the same concerns over the transition time periods Mr. Michel proposes as with the Joint Proposal, as discussed by Mr. Hoogeveen and Mr. Meredith. In addition, I'm concerned that the banded rate credit and annual cap proposed for the transition period[20] would be confusing to customers, challenging to implement, and lacking in evidence for the adjustments in the credits. The proposal to wait until 2020 to initiate the docket

[18] *Id.* at ll. 355-65.
[19] WRA witness Steve Michel, Rebuttal Testimony, ll. 48-120.
[20] *Id.* at 104-9.

to set an export credit going forward[21] also unnecessarily delays moving forward and providing certainty to both the industry and customers.

Q. WRA recommends that the Commission should indicate now that a separate rate class or a demand charge for residential customers is not in the public interest to provide some certainty to the solar market.[22] How do you respond?

A. While I believe the record supports a finding that a separate class and rate design, including a demand charge option, for residential NEM customers is in the public interest, as I noted above in the response to the Joint Proposal, the Commission should not pre-judge or preclude potential future evidence on rate design or the creation of new rate classes. No other customer has this certainty.

Response to Rebuttal of Vote Solar witness Dr. David DeRamus

Q. Dr. DeRamus argues that the Company's "lost revenue attributable to other residential load reduction programs, such as energy efficiency programs, far exceeds the amount of lost revenue attributable to behind-the-meter generation by residential NEM customers."[23] Even if there were a greater reduction in revenue from demand-side management than there is for private generation, does that mean that it would be unreasonable to charge different prices to customers with private generation or to otherwise modify the net metering program?

A. No. While the overall magnitude of reduced revenue from energy efficiency may be greater than reduced revenue from private generation, there are key differences between the two that cause the need for changes to the NEM program in its current form,

[21] *Id.* at 111-2.
[22] *Id.* at 118-20, 504-21.
[23] Vote Solar witness David DeRamus Rebuttal Testimony, ll. 72-75.

particularly for residential customers. For one, NEM is not necessarily akin to energy efficiency or conveys the same benefits. The difference with energy efficiency programs was discussed in my direct testimony in the last phase of this proceeding, dated July 30, 2015. In short, energy savings from efficiency measures occur at the time that the customer would otherwise use that energy. In contrast, private generation may or may not produce energy at the time a customer requires energy. NEM is also a different service than demand-side management programs since NEM requires the utility to back-up the customer generation facility and provides a vehicle for the customer to export power to the system, which does not diminish the customer's reliance on the utility system. It is not the overall magnitude of reduced revenue, but rather the incremental potential for cost shifting with each additional interconnection that drives the need for changes in how customers with private generation are compensated.

Q. Dr. DeRamus discusses how he believes that the OCS's proposal to compensate private generation customers with a credit for exported energy that is lower than retail rates could "encourage customers to install home battery storage systems simply in order to effectively 'disconnect' from the grid." He then describes this as "relatively inefficient and expensive" and claims it "would only exacerbate RMP's challenges associated with fixed cost recovery."[24] Please comment.

A. Dr. DeRamus' concerns with the potential for changes to the NEM program driving customers to install battery systems to consume more of their private generation onsite

[24] *Id.* at ll. 178-99.

ignore a couple of things. For one, while he concedes that "the further development and deployment of residential battery storage systems to be beneficial," he also expresses a concern that batteries could further erode the Company's fixed cost recovery. However, with the current NEM paradigm that provides for netting and banking to offset future usage, residential customers already have the ability to size their solar installations to eliminate all usage charges during a year (*i.e.*, be net-zero), except for the customer charge. So customers already have the ability to provide minimal cost recovery; batteries wouldn't necessarily exacerbate that situation. Second, with netting and banking, the utility is effectively acting a battery for NEM customers, yet Dr. DeRamus fails to consider that this is a cost of the program. Batteries are expensive, as is providing that virtual service to NEM customers, as shown in the compliance analyses.

Q. Dr. DeRamus argues that having an export credit that is less than retail rates would send a perverse incentive for customers to shift their usage from off-peak hours to the middle of the day and would encourage customers to effectively disconnect from the grid by installing battery storage.[25] Do you agree with these claims?

A. No. A central premise of the Company's position is that customers should pay for the service they require from the grid.[26] If a customer with a solar system and a battery is able to *reliably* dispatch that battery to serve household consumption, the customer would likely impose less costs on the Company's system than a customer with only solar panels and no battery, therefore the rates should and do reflect this under the

[25] *Id.* at ll. 184-204.
[26] *See* Company witness Gary Hoogeveen, Rebuttal Testimony, ll. 16-18.

Company's proposal and would be a correct incentive. Under the Company's proposed rates, if a customer uses a battery to reduce all on-peak usage, those system cost savings will accrue to the customer by avoiding all on-peak demand or energy charges.

In addition, encouraging customers to shift their consumption to when their systems can serve is not a perverse incentive and instead, is the primary purpose of private generation. In contrast to Dr. DeRamus's implication, the middle of the day is not a more costly time for the Company to serve as it is not when the peak occurs. Exhibit RMP___(JRS-4) from my direct testimony shows that the Company's peaks occur in the late afternoon/early evening during the summer and the late afternoon/early evening and morning during the winter. Consequently, the off-peak period for the Company's proposed Schedule 5 rates does not include the period from 10 am until 3 pm, when rooftop solar typically operates. Proposals that encourage private generators to use the output from their facilities during the middle of the day is an appropriate price signal.

Q. Does this conclude your surrebuttal testimony?

A. Yes.

Rocky Mountain Power
Docket No. 14-035-114
Witness: Robert M. Meredith

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Surrebuttal Testimony of Robert M. Meredith

August 2017

Q. Are you the same Robert M. Meredith who presented direct and rebuttal testimony in this proceeding?

A. Yes I am.

Purpose of Surrebuttal Testimony

Q. What is the purpose of your surrebuttal testimony?

A. In this testimony, I present calculations of the estimated cost shifting that would occur under various proposals presented by other parties. I also respond to the rebuttal testimonies related to the Company's cost of service analyses of Utah Clean Energy ("UCE") witness Tim Woolf, Vote Solar witness Dr. David DeRamus, and Vivint Solar witness Richard Collins. Many of the arguments made in interveners' rebuttal testimonies are similar to those espoused in their direct testimony. Consequently, I did not attempt to respond to every contention concerning the Company's cost of service analyses that were made by interveners in rebuttal testimony. Silence on any argument made by other parties does not imply assent on my part.

Projections of Cost Shifting from Various Proposals

Q. Did you prepare estimates of the level of cost shifting that would occur for different potential futures for the net metering program and the successor program as proposed by different parties?

A. Yes. Exhibit RMP___(RMM-1SR) shows the estimated 19-year present value of revenue requirements ("PVRR") and nominal value of cost shifting for residential net energy metering ("NEM") for several proposals including the following:

(1) the status quo if no changes were made to the NEM program;

(2) the Company's filed case as revised in rebuttal testimony;

(3) the low end and high end of the Joint Proposal by Office of Consumer Services ("OCS") and Division of Public Utilities' ("DPU") presented in their rebuttal testimonies;[1] and

(4) Western Resource Advocates' ("WRA") proposal presented in its rebuttal testimony with a simplifying assumption incorporated.

The 19-year PVRR of cost shifting on Exhibit RMP___(RMM-1SR) are shown to be $291 million, $62 million, $143 million, $178 million, and $195 million for the status quo, the Company's case, the low end of the Joint Proposal, the high end of the Joint Proposal, and WRA's proposal, respectively. In addition, Exhibit RMP___(RMM-1SR) shows estimated cost shifting impacts for some alternative scenarios for context that I will describe later in my testimony.

Q. How did you prepare these estimates?

A. Using the base case of Navigant's private generation forecast that was used for the Company's 2017 Integrated Resource Plan ("IRP"), existing and proposed average offset rates were multiplied by forecast private generation in each year that would be applicable to either existing NEM customers, transition customers, or post-transition customers to calculate annual reductions in revenue. An offset rate sufficient to achieve no cost shifting was then multiplied by private generation and subtracted from the reductions in revenue each year to determine annual cost shifting. For the status quo scenario, an administrative shortfall was added to annual cost shifting by multiplying new forecast residential private generation by the Company's proposed $60 application

[1] DPU witness Dr. Artie Powell DPU, Rebuttal Testimony, Exhibit 1.1R, and OCS witness Michele Beck, rebuttal testimony, Attachment 1 ("Joint Proposal").

fee. To determine the PVRR for each scenario, the net present value of the 19-year stream of annual cost shifting values was calculated using a discount rate of 6.57 percent.[2]

Q. Why was 19 years used?

A. Nineteen years reflects the period of time between 2018, when the different proposals recommend changes to the NEM program, and 2036, which is the last year of the private generation forecast.

Q. What simplifying assumption did you incorporate into the estimated cost shifting from WRA's proposal?

A. In WRA's proposal, it recommended a "soft cap" of 250 megawatts with adjustments made to its proposed nine cent per kilowatt hour export credit rate, either up or down, depending upon the annual adoption levels.[3] Considering potential uncertainty with the year-by-year forecast of private generation, I did not think modeling these changes up or down to the export credit rate would yield meaningful results. For my cost shifting estimate of WRA's proposal, I assumed that the full 250 megawatts of private generation would receive a nine cent export credit rate and all additional megawatts would be on a post-transition rate.

Q. For context, what is the incremental cost shifting that occurs with each one cent per kilowatt-hour change in the export credit price for transition customers?

A. Applying an incremental one cent more per kilowatt-hour for the export credit to the 200 megawatts for the transition program in the Joint Proposal, I calculate an increase

[2] See 2017 IRP, Vol. 1 at p. 150.

[3] WRA witness Steven S. Michel Rebuttal Testimony, ll. 104-9.

in cost shifting to non-NEM customers of about $1 million per year. Over a 12 to 17 year period, I estimate an incremental one cent increase in the export credit rate results in about $15 million to $22 million more cost shifting, respectively, to non-NEM customers.

Q. For additional context, please quantify the estimated cost shifting associated with a transitional export credit at 6.7 cents per kilowatt-hour, which the DPU supported in its direct testimony,[4] as well as the cost shifting that would occur for an export credit that is at about 3.3 cents per kilowatt-hour, which is the Schedule 37 levelized avoided cost price expanded by the secondary line loss factor, at both the low and high ends of grandfathering in the Joint Proposal.

A. Exhibit RMP___(RMM-1SR) shows the estimated 19-year PVRR for these different levels of export crediting to be $115 million, $141 million, $84 million, and $101 million for the low end of grandfathering and transition periods with a 6.7¢/kWh transition export credit, the high end of grandfathering and transition periods with a 6.7¢/kWh transition export credit, the low end of grandfathering and transition period with a 3.3¢/kWh transition export credit, and the high end of grandfathering and transition period with a 3.3¢/kWh transition export credit, respectively.

Q. What do you estimate the incremental impact to cost shifting would be if a five-year period instead of a 10-year period for a transition period at a 6.7¢/kWh export credit were used?

A. Exhibit RMP___(RMM-1SR) shows taking the low end for the 6.7¢/kWh export credit and shortening the term of the transition period to five years would result in an

[4] DPU witness Dr. William Powell Direct Testimony, ll. 528-40.

estimated PVRR of about $101 million, or about a 12 percent decrease in cost shifting.

Rebuttal of UCE witness Tim Woolf

Q. Mr. Woolf claims that the Company developed a CFCOS and an ACOS, but did not present a direct comparison of them and instead added bill credits onto the results of the cost of service studies.[5] Is his assertion correct?

A. Not at all. Exhibit RMP___(RMM-2) in my direct testimony and Exhibit RMP___(RMM-3R) in my rebuttal testimony very clearly present a direct comparison of the results of the CFCOS and ACOS, which includes the impact of bill credits. Exhibit RMP___(RMM-1) in my direct testimony and Exhibit RMP___(RMM-1R) in my rebuttal testimony categorize the differences between both studies into costs and benefits at the system, state, and customer class levels. Bill credits were not added outside the models as Mr. Woolf seems to indicate. Mr. Woolf's statement reflects a misunderstanding of the Company's filing.

Q. Mr. Woolf argues that including bill credits as a cost of net metering is "contrary to the Commission's order that 'The categories of costs in both studies should generally be consistent with those PacifiCorp employs in preparing cost of service studies for ratemaking purposes.'"[6] Are revenues a key component of a cost of service study?

A. Yes. Revenues are a key input into a cost of service study. Bill credits associated with the NEM program which reduce revenue clearly impact the results of a cost of service study, as can be observed on Exhibit RMP___(RMM-2) in my direct testimony and as

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[5] UCE witness Tim Woolf Rebuttal Testimony, ll. 58-61.

[6] *Id.* at ll. 62-64.

updated in Exhibit RMP___(RMM-3R) in my rebuttal testimony.

Rebuttal of Vote Solar witness Dr. David DeRamus

Q. Dr. DeRamus asserts that "RMP's approach mistakes a reduction in its revenue for an increase in the cost of service."[7] Was this a mistake?

A. No. As I discussed in my rebuttal testimony[8] and earlier in this testimony, a change in revenue impacts the cost of service result for a class. In other words, if revenue is reduced, either a greater increase or a lesser decrease will be required to bring a customer class to full cost of service.

Q. Do you agree with Dr. DeRamus that the Company's data are "stale" and therefore do not provide "a reliable factual basis on which to draw reasonable conclusions regarding the costs and benefits?"[9]

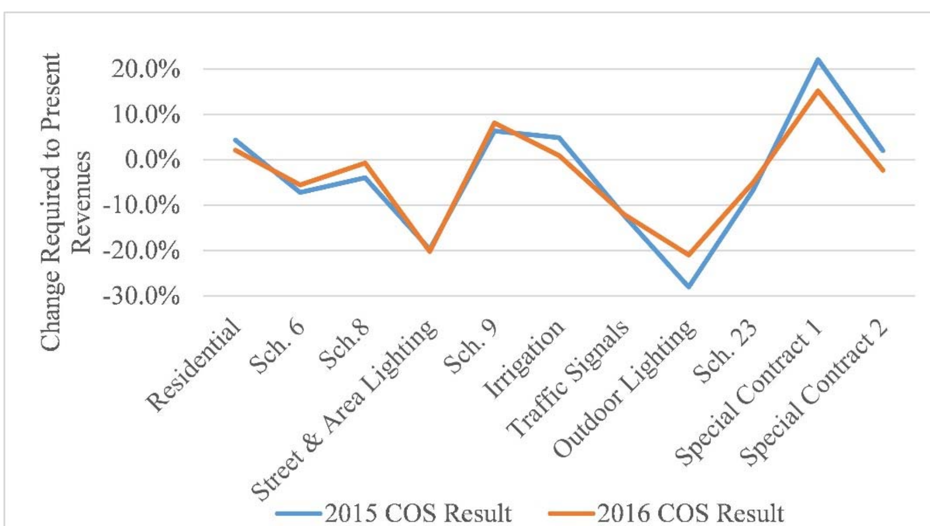
A. No. The Company's studies are based upon a 2015 calendar year historical period. They are based upon a historical period to avoid any controversy that could exist with a forecast and are the earliest period of time under which the Company had a full year's worth of data for its net metering load research study. The studies are based upon the Company's results of operations filed on April 29, 2016, and the annual cost of service study filed on June 15, 2016. Allowing time to prepare its studies and review, the Company made its filing on November 9, 2016. The current procedural schedule has then brought the filing of this testimony and the hearings into August 2017, less than two years after the completion of the historic test period. Given the complexities of the studies necessary to comply with the framework, adequate time has been needed both

[7] Vote Solar witness David DeRamus Rebuttal Testimony, ll. 69-70.
[8] Company witness Robert M. Meredith Rebuttal Testimony, ll. 67-75.
[9] *Id.* at ll. 113-14.

for the Company to prepare its filing and for other parties to review it. With any proceeding that entails technical information or analysis, there is always some lag in the time period for the underlying data and the time at which a Commission can render a decision. The only way to provide a more contemporaneous set of studies would be to require less time for review for all parties.

Further, Dr. DeRamus provides no evidence that a more recent period would alter the finding from the analysis prepared under the Commission's ordered framework that costs exceed benefits for the net metering program or would have a very different magnitude of relative cost shifting for residential NEM. Comparing the results from the 2015 annual cost of service study filing to the 2016 annual cost of service study filing recently made on June 15, 2017, shows that while there were some changes for the different periods, the general pattern of increases or decreases required to bring each class to full cost of service was the same. See Figure 1 below for a comparison of cost of service results between these two periods.

Figure 1. Class Cost of Service Result - 2015 Compared to 2016



Given the very modest differences between classes shown on Figure 1, I doubt that using calendar year 2016 would yield results for the net metering program that would be much different. Like many other parties who have a strong interest in perpetuating the subsidization of the rooftop solar industry that benefits from retail rate remuneration, Dr. DeRamus would like to claim any reason to delay, postpone, or otherwise put off a determination of costs and benefits for the NEM program.

Q. Does Dr. DeRamus have any basis for his statement that the Company's "conclusions regarding the costs and benefits to serve residential NEM customers are based on unsupported conjecture, not reasoned analysis and reliable data?"[10]

A. No. The Company's analyses comply with the November 2015 Order, are based upon a substantial body of evidence, and employ methods that have been relied upon historically for setting the Company's retail rates, which have been found to be just and reasonable. Dr. DeRamus provides no evidence that the Company's calculation of costs and benefits is unsupported conjecture. His arguments presented in both his direct and rebuttal testimonies do not demonstrate a lack of support for the Company's analyses, but rather present his views for why the Commission's framework is not his preferred approach.

[10] *Id.* at ll. 125-26.

Q. Dr. DeRamus concludes that the evidence for the Company's finding that the costs of the NEM program exceed its benefits is insufficient, "particularly given the current low level of residential DSG penetration."[11] Would the overall magnitude of the NEM program influence a finding of costs and benefits under the framework ordered by the Commission in its November 2015 Order?

A. No. I am not sure why Dr. DeRamus would claim that the finding of costs exceeding the benefits would be impacted by a lower level of penetration. While a smaller number of residential NEM customers would create less overall cost shifting, I think that the general level of cost shifting for each additional unit (customer, megawatt, or megawatt hour) of residential NEM that interconnects would be similar under the framework afforded by the November 2015 Order irrespective of magnitude.

Rebuttal of Vivint Solar witness Richard Collins

Q. Mr. Collins references a PVRR benefit of about $400 million for higher penetrations of distributed generation from the Company's 2017 IRP over 20 years.[12] Does this prove that the net metering program provides net benefits?

A. No. As I discussed in my rebuttal testimony, the IRP sensitivity cases only measure future benefits associated with rooftop solar and do not include incremental costs such as bill credits.[13]

Q. Please provide some context for the $400 million benefit that Mr. Collins references.

A. The 20-year PVRR that Mr. Collins references is actually less than the benefits afforded

[11] *Id.* at ll. 354-58.
[12] Vivint Solar witness Richard Collins Rebuttal Testimony, ll. 46-50.
[13] Company witness Robert M. Meredith Rebuttal Testimony, ll. 345-47.

to net metering through the cost of service-based framework ordered by the Commission in its November 2016 Order. Using some of the same assumptions I presented earlier in this testimony to project cost shifting and a benefit value of $67.14[14] per megawatt hour developed from Exhibit RMP___(RMM-2R) in my rebuttal testimony, I calculate that the 20-year PVRR of total benefits excluding costs for residential NEM would be about $459 million.

Q. Mr. Collins argues that the Commission made a "grave error" in the November 2015 Order which included a one year test period, since "(i)f one is required to look at only one year's worth of costs and benefits, no dam would ever get built; there would be no long-term investments made by businesses or anyone for that matter." Please comment.[15]

A. I think that Mr. Collins's argument is misleading. He seems to imply that the benefits included under the framework that the Commission required in the November 2015 Order are limited only to short-term costs. As I have indicated in my rebuttal testimony,[16] the Company's analyses consider lower allocations of facilities which have long lives as a benefit of the NEM program. Further, retail rates themselves are determined based upon a one-year test period and individuals and businesses make significant long-term investments in energy efficiency in response to them.

[14] On page 3 of Exhibit RMP___(RMM-2R), $67.14 can be calculated by taking $1,900,000 total benefit for residential divided by 28,304 megawatt hours of private generation.
[15] Vivint Solar witness Richard Collins Rebuttal Testimony, ll. 87-91.
[16] Company witness Robert M. Meredith Rebuttal Testimony, ll. 86-88.

Q. Mr. Collins makes some recommendations for a future load study including having "at least one observation per usage strata for each county," "multiple years of data," and weather normalization.[17] Please comment.

A. While the Company is open to and may agree to implement some reasonable level of additional load research data to achieve even more accurate results for a potential future proceeding or phase of this proceeding, his suggestions would be best addressed as part of a work group or collaborative in that future potential proceeding or phase of this proceeding. In his rebuttal testimony, Mr. Collins provides no support for why multiple years, weather normalization, and data for all counties are necessary.

Q. Does this conclude your surrebuttal testimony?

A. Yes.

[17] *Id.* at ll. 533-37.

Rocky Mountain Power
Exhibit RMP___(RMM-1SR)
Docket No. 14-035-114
Witness: Robert M. Meredith

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Surrebuttal Testimony of Robert M. Meredith

19 Year Cost Shifting for Different Potential Futures for the Net Metering Program

August 2017

Rocky Mountain Power
State of Utah
19 Year Cost Shifting for Different Potential Futures for the Net Metering Program

Name	Transition Export Credit	Transition Cap (Until 1/1/2021)	Transition Program Period	Current NEM Grandfathering	Cost Shifting PVRR ($m) 19 Years	Nominal Cost Shifting ($m) 19 Years
Status Quo					290.7	584.1
Company Filing					62.2	110.8
DPU/OCS Rebuttal - Low	$98/MWh	200 MW	Ends 1/1/2028	Ends 1/1/2030	142.5	214.9
DPU/OCS Rebuttal - High	$98/MWh	200 MW	Ends 1/1/2033	Ends 1/1/2035	177.8	300.5
WRA Rebuttal	$90/MWh	250 MW	Ends 1/1/2035	Ends 1/1/2035	194.5	341.5
DPU Direct - Low	$67/MWh	200 MW	Ends 1/1/2028	Ends 1/1/2030	115.0	176.0
DPU Direct - High	$67/MWh	200 MW	Ends 1/1/2033	Ends 1/1/2035	141.4	241.2
DPU Direct - Low - 5 Year Transition	$67/MWh	200 MW	Ends 1/1/2023	Ends 1/1/2030	101.2	153.2
Avoided Cost + Losses - Low	$33/MWh	200 MW	Ends 1/1/2028	Ends 1/1/2030	84.2	132.4
Avoided Cost + Losses - High	$33/MWh	200 MW	Ends 1/1/2033	Ends 1/1/2035	100.6	174.7

CERTIFICATE OF SERVICE

I hereby certify that on August 8, 2017, a true and correct copy of the foregoing document was served by email on the following Parties in Docket No. 14-035-114:

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