BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

IN THE MATTER OF THE INVESTIGATION OF THE COSTS AND BENEFITS OF PACIFICORP'S NET METERING PROGRAM	)))))))))	**DOCKET NO. 14-035-114** **DPU Exhibit 2.0R**

COST OF SERVICE

(NET METERING PROGRAM)

REBUTTAL TESTIMONY OF STAN FARYNIARZ

ON BEHALF OF

THE UTAH DIVISION OF PUBLIC UTILITIES

July 25, 2017

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I. INTRODUCTION

Q. What is your name?

A. My name is Stan Faryniarz.

Q. Are you the same Stan Faryniarz who filed Direct Testimony in this proceeding?

A. Yes.

Q. What is the purpose of your testimony?

A. I wish to respond to certain arguments made by other intervenors in their direct testimony in this proceeding. Specifically, I address the following:

- Analysis of the net metering program cost and benefits as they relate to utility-scale versus distributed generation, and value of solar calculations presented by EFCA.
- Cost of service analysis issues related to the characterization of bill credits.
- Use of the Company's recently filed Integrated Resource Plan as a source to calculate net metering program costs and benefits.
- Price signals from time-based demand charges versus time of use energy rates, and metering and other reforms that allow for accurate time of day and seasonal price signals.

My testimony is laid out to first summarize the direct testimonies and comments put forward by other intervening parties. I then address specific arguments, related to the issues listed above, made by the witnesses for the other intervening parties. Therefore, the main substance of my rebuttal testimony begins in Section III. Issues and Analysis.

My testimony is in conjunction with the other Division of Public Utilities' witnesses Artie Powell, Ph.D. and Ms. Myunghee Tuttle. Dr. Powell responds to Mr. Eliah Gilfenbaum's[1] assertions about the Company's earnings and long-term value of net metering exports. Dr. Powell also addresses comments about the Company's one-year test year for its cost of service studies, use of the Company's Integrated Resource Plan process to determine net metering benefits, and the discusses the joint proposal put forward by the Division of Public Utilities and Office of Customer Services. Ms. Tuttle responds to the customer charge proposals offered by the Office of Consumer Services' witness Mr. Danny A.C. Martinez.

Q. Please summarize your conclusions and recommendations.

A. My conclusions and recommendations include:

- Customers should not be forced to pay a much higher cost for distributed solar from their neighbors if the utility can offer it at a much lower cost from large projects.
- At the same time, utilities should not overlook distributed generation as an important potential resource in their system planning.

[1] Witness for the Energy Freedom Coalition of America.

- Customers who obtain power from the grid, regardless of whether they also supply some of their own generation, must pay an appropriate cost-based rate for that service.
- Under traditional utility ratemaking, a utility is not entitled to recover "lost revenues," but it is entitled to recover its prudently-incurred costs.
- Effective price signals can be provided by time-based demand charges.
- A future distributed generation rate design should consider both demand-based and TOU-based time varying rates, implemented gradually to ensure bill impacts are modest, at least initially, and become well-understood by customers.
- A future distributed generation rate design should send accurate price signals to all customers, corresponding to the cost and value of consumption and export periods they are in effect, respectively, which requires appropriate metering, data communication and customer understanding.

II. INTERVENOR TESTIMONY SUMMARIES

Q. Who are the intervening parties in this proceeding?

A. In addition to RMP, the Office of Consumer Services ("OCS"), and the Division of Public Utilities ("DPU"), there are nine additional intervening parties that provided written analysis in this proceeding, including renewable industry trade associations, ratepayer representative organizations, solar energy system installers, environmental advocacy groups, individual utility ratepayers, and a municipality. Eight of these parties submitted pre-filed testimony and one filed written comments, and my testimony here focuses upon the positions of those parties. Testimony was sponsored by Sierra Club, Summit County, Utah Clean Energy ("UCE"), Utah Solar Energy Association ("USEA"), HEAL Utah ("HEAL"), Vivint Solar, Inc. ("Vivint Solar"), Vote Solar, Energy Freedom Coalition of America ("EFCA"), and the Office of Consumer Services ("OCS"). Written comments were submitted by Utah Association of Energy Users ("UAE").

Q. Please provide a brief summary overview of each party's initial filing.

A. Below is a description of the filings and some key points made by each of the parties regarding the issues relevant to RMP's residential NEM rate design proposal. Note that the following summary does not purport to highlight every argument made by every party. Additionally, in restating parties' positions in this Section II, note carefully that the DPU does not imply it agrees with those positions. Rather, what follows are restatements of parties' contentions, not a DPU characterization of its response to those contentions. Thereafter, I do address in rebuttal several specific positions of certain parties, where relevant, in Section III. Issues and Analysis.

A. Sierra Club

Sierra Club's witness Allison Clements asserts that RMP's proposal for a three-part rate structure is discriminatory and harmful to the Company's rooftop solar customers due to the high fixed rate, reduced volumetric charge, and improper demand charge associated with the rate plan.[2] Regarding the demand charge, Ms. Clements explains that while a demand charge may be fitting in the industrial customer class, it is inappropriate for

[2] Sierra Club Direct Testimony of Allison Clements, p. 24, lines 438-441.

residential customers since the usage profiles of these customers have a lesser impact on the size and reliability of the system than those of industrial customers. Furthermore, demand charges do not incentivize residential customers to reduce their demand since they are generally unable to respond to demand price signals.[3] She contends the Company's "proposed demand charge is a poor proxy for attempting to align rooftop solar customers' cost of service with the rates they are charged for that service" and the failure of several utilities to implement such a charge on rooftop solar customers in the last few years illustrates the unorthodoxy of this approach.[4]

Ms. Clements addresses RMP's claim that the cost of service ("COS") burden is being transferred from residential rooftop solar customers to other residential customers because rooftop solar customers are buying less energy. She states that the Company's cost shifting assertion is not properly supported, the cost of service studies the Company conducted are flawed and therefore unable to demonstrate any level of cost shift.[5] Additionally, since cost of service studies are based on a "one-year snap shot of costs" by design, these studies do not address the long-term benefits provided to the Company's system by distributed solar resources.[6] She adds that another flaw with RMP's analysis is the utilization of "production profiles of only 36 residential rooftop solar customers".[7]

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[3] *Id.*, p. 18, lines 327-331.
[4] *Id.*, p. 18, lines 336-346.
[5] *Id.*, p. 26, lines 472-476.
[6] *Id.*, p. 27, lines 491-493.
[7] *Id.*, p. 27 lines 501-502.

Ms. Clements maintains these limitations of the cost of service studies significantly diminish the robustness of their conclusions.

Beyond the cost of service studies, Ms. Clements argues that cost shifts are a typical part of cost-of-service rate design and therefore this cost shift may not warrant special consideration, especially in light of the other cost shifts that may be occurring.[8] After conducting her own analysis on how the cost shift claimed by RMP may be harming other residential customers, by dividing residential customers into three separate usage classes, Ms. Clements concludes that the cost shift is not imposing a significant burden on any of these groups.[9]

To conclude her testimony, Ms. Clements provides a discussion of the consequences tied to the imposition of rooftop solar rate design polices in other states like those proposed by RMP. As demonstrated by the experience of Nevada, she suggests the establishment of a rate structure like the rate design in RMP's proposal can lead to serious, long-term damage to the rooftop solar industry.[10] In contrast, she describes how Colorado can be used as an example to show how "collaboration and gradualism" will help the solar industry grow.[11] Specifically, she explains that decoupling could be used in unison with

[8] *Id.*, p. 32, lines 597-604.
[9] *Id.*, p. 36, lines 665-669.
[10] *Id*., pp. 43-44, lines 791-799.
[11] *Id*., p. 55, lines 981-982.

the final rate design as a solution to the Company's declining revenues due to increased growth of rooftop solar.[12]

B. Summit County

Summit County witness Roger Armstrong discusses the cost-benefit and methods associated with RMP's compliance filing and how it will impact the residents of Summit County and its current renewable energy system. As a net metering customer of RMP, the county and its residents are concerned with how the Company's proposed rate structure will impact its commitment to renewable energy and pollution reduction.[13] Summit County takes issue with RMP's rate design approach because it is based on the faulty premise that the Utah electric power market is a free market system.[14] The Company already has special privileges, such as "monopolistic powers, guaranteed profit, subsidies, and government police powers such as eminent domain", that allow it to restrict access to the electrical grid in Utah.[15] Since the net metering program is designed to allow elements of competition to enter the electrical power market, the Commission should not accept changes to this program that would result in new barriers to market access.[16] Summit County suggests that the removal of barriers by the Commission, such as adopting a broader view of the long term benefits afforded by rooftop solar, will bring

[12] *Id*., p. 54, lines 961-965.
[13] Summit County Direct Testimony of Roger Armstrong, pp.2-3, lines 13-36.
[14] *Id*., p. 3, lines 40-42.
[15] *Id*., p. 3, lines 44-46.
[16] *Id*., p. 4, lines 62-65.

down costs for customers and is in the best interest of the residents of both the county and the state of Utah.

Additionally, Summit County addresses the cost-benefit analysis of the net metering program conducted by RMP. Mr. Armstrong explains that RMP's cost-benefit analysis does not recognize the value provided to neighborhoods and communities by distributed generation, such as the provision of renewable power from net metered customers at no cost to local households.[17] The local power provided by net metered customers helps reduce transmission line losses, lessens the amount of electricity production needed from RMP, and lowers harmful emissions.[18] Summit County asserts that RMP's 3-tier rate plan proposed through Schedule 136 and Schedule 5 will reduce the average 900 kW/month solar rooftop customer savings from $133/month to $74/month, which will essentially end the net metering program in Utah and therefore impact the county and its sustainability goals.[19]

C. UCE

UCE's witnesses discuss the Company's analysis of net metering costs and benefits, the new rates proposed for distributed generation customers, grandfathering for current NEM customers, and long-term approaches for developing distributed generation ("DG") rate structures. The direct testimony of Tim Woolf focuses on the cost and benefits of the net

[17] *Id*., p.5, lines 86-89.
[18] *Id*., p.5, lines 90-92.
[19] *Id*., p.6, lines 97-102.

metering program, finding that RMP's own cost of service analyses show the current net metering program provides net benefits to customers, even though the Company understates net metering benefits due to only featuring one year of data in its cost of service studies.[20] Additionally, UCE witness Woolf finds that the Company's proposed net metering compensation mechanism will make distributed solar less economically feasible thereby reducing the impetus for residential customers to install distributed solar systems in the future.[21] He further finds that the Company "conflated the cost-benefit analysis of net metering with cost-shifting," which makes it difficult to draw clear conclusions regarding the effect of either one.[22] Regarding cost-shifting, Mr. Woolf suggests that RMP's analysis overstates the impacts of cost-shifting caused by distributed generation because it undervalues DG benefits and assumes all lost revenues DG creates will be recouped from customers.[23] Lastly, Mr. Woolf finds that the expansion of solar DG is consistent with RMP's 2017 Integrated Resource Plan ("IRP"), which shows that increased penetrations "can reduce the cumulative net present value of revenue requirements by more than $440 million."[24]

Based on his findings, Mr. Woolf recommends the Commission find that current NEM program benefits outweigh the costs, that RMP's analysis of the current NEM program does not show a cost-shift from NEM to non-NEM customers, and that a future

[20] UCE Direct Testimony of Tom Woolf, p. 4-5, lines 79-85.
[21] *Id*., p. 4, lines 73-75.
[22] *Id*., p. 4, lines 76-78.
[23] *Id*., p. 23, lines 424-430.
[24] *Id*., p. 5, lines 81-83.

compensation mechanism for DG should allow for continued growth of DG installation.[25] Further, he recommends that the Commission require future DG cost-benefit and cost-shifting analyses be conducted separately with the cost-benefit analysis based on revenue requirements not bill credits, which should be accounted for in the cost-shifting analysis.[26] Lastly, he recommends the Commission require a 20-year study period be used for cost-benefit analyses due to costs and benefits occurring beyond one year.[27]

UCE witness Melissa Whited focuses more specifically on the proposed residential tariff and finds the following: the reduced economics of DG under the Company's proposed residential DG tariff would cause few customers to install DG in the future; residential customers are not suited for demand charges; and DG customers should not be placed in a separate rate class from other residential customers because their load characteristics do not justify the segregation and it would only cause an increase in the costs to serve non-NEM customers.[28] Based on her findings, witness Whited recommends the Commission should: reject the Company's rate design proposal because it eliminates the economics of installed DG; find that residential customers are not suited for demand charges; DG compensation should "strike a balance between enabling reasonable growth in distributed generation, while mitigating cost-shifting to non-net metered customers" and be modified over time as conditions change; and if any changes to the NEM program do occur, "only

[25] *Id*., p. 5, lines 92-98.
[26] *Id*., pp. 5-6, lines 99-104.
[27] *Id*., p. 5, lines 105-107.
[28] UCE Direct Testimony of Melissa Whited, p. 3, lines 44-54.

the compensation for monthly net excess generation be reduced" and this compensation "should be based on the best estimate of long-term benefits, including the benefits of avoiding large capital investments.[29]

When analyzing the Company's cost of service studies, witness Whited found that the studies show that DG actually reduces revenue requirements, which leads to lower costs for all customers.[30] Further, she found that the results of the Actual Cost of Service ("ACOS") and NEM Breakout cost of service studies show that placing NEM customers in a separate rate class would actually cause the cost allocation, on a per-customer basis, to non-NEM customers to increase.[31] This suggests that the separation of NEM customers into a separate rate class would also not shield customers from cost-shifting.

Regarding demand charges, Ms. Whited asserts that demand charges are not appropriate for residential customers because they violate widely-accepted ratemaking "principles of efficiency, simplicity, and stability".[32] She explains how demand charges provide a less efficient price signal than other rate designs, are complicated in design, and do not ensure rate stability.

Witness Whited concludes her testimony by presenting several recommendations regarding the DG rate design, demand charges, and compensation. She recommends that

[29] *Id*., pp. 3-4, lines 58-78.
[30] *Id*., pp. 15-16, lines 259-264.
[31] *Id*., p. 20, lines 311-313.
[32] *Id*., p. 23, lines 387-388.

if the Commission modifies the current NEM program, it should only reduce excess generation compensation or in the alternative suggests time-of-use ("TOU") pricing be implemented to send proper price signals.[33] She offers the suggestion of gradually stepping down the compensation for excess generation over time as solar penetration levels increase[34] Lastly, she explains that if netting was changed from monthly to hourly, customer bills may dramatically change and therefore netting should remain monthly until there is a better understanding of hourly netting impacts.[35]

UCE's last witness, Justin Barnes, discusses the issue of grandfathering for existing NEM customers and long-term designs for improving DG rate structures. Mr. Barnes discusses and provides an evaluation table that shows how regulatory commissions in several states have approached grandfathering for existing DG customers in the context of NEM program and rate design structural changes for these customers.[36] He generally finds that grandfathering is widely supported by regulators, usually lasts 20 years or more, and eligibility is based on application submissions before or on a decision date or benchmark.[37] Mr. Barnes recommends that existing DG customers, "defined as those that submit an interconnection application before the latter of the date of a final Commission order in Docket No. 14-135-114 or the effective date of any tariff changes", be grandfathered for 20 to 25 years on the currently applicable rate structure.[38] He further

[33] *Id*., p. 33, lines 559-565.
[34] *Id*., p. 34, lines 575-578.
[35] *Id*., p. 34, lines 583-589.
[36] UCE Direct Testimony of Justin R. Barnes, pp. 11-19, lines 191-320.
[37] *Id*., p. 12, lines 205-210.
[38] *Id*., p. 4, lines 37-41.

recommends that future DG customers should also be grandfathered for a period of 20 to 25 years "to support long-term investments under any new rate design in this proceeding".[39] Finally, he recommends that the Commission gradually develop DG rate structures that target long-term solutions for incorporating DG into the electric system.[40]

D. USEA

USEA addresses the rooftop solar industry in Utah and nationally, how the solar industry has benefited Utah, and the detrimental effect RMP's proposal would have on participation in NEM programs.[41] USEA states that they strongly support the current NEM policy in Utah, since it satisfies customer demand for these programs and has a positive effect on different parts of Utah's economy, such as generating competition in the solar market, energy source diversification, energy price reduction, grid security, and grid stability.[42] USEA claims that RMP's rate structure proposal will make rooftop solar uneconomic in Utah, which will lead to slowing down or completely stopping the state's solar economy, and cites the situation in Nevada where a similar rate structure was introduced.[43] Therefore, USEA recommends that the Company's proposal be rejected by the Commission and [that it should] instead "adopt a rate structure that fairly and adequately incents them [customers] to participate in NEM programs."[44] However,

[39] *Id*., p. 4, lines 44-45.
[40] *Id*., p. 4, lines 42-43.
[41] USEA Direct Testimony of Ryan Evans, pp. 3-4, lines 41-48.
[42] *Id*., p. 5, lines 84-89.
[43] *Id*., p. 9, lines 157-162.
[44] *Id*., p. 9, lines 165-167.

USEA does agree with RMP's proposal in that grandfathering of current NEM customers should continue on their current rate schedule under the current NEM program.[45]

USEA witness Micah Stanley points to several errors and incorrect methods in the Company's cost of service studies which obscure the net benefit actually produced by the NEM program.[46] Mr. Stanley claims that a one-year test period is an inadequate amount of time to collect reliable NEM program cost and benefit data.[47] He further claims that the Company's methodology is flawed because it excludes "significant benefits of the NEM program" and relies only on data collected from a small sample of NEM customers.[48] Some of the omitted quantifiable benefits of the NEM program he believes were excluded in the cost of service studies include benefits from system upgrades from NEM customers, positive contributions associated with locally produced energy, and benefits from upgrades to smart meters.[49] Additionally, Mr. Stanley claims that there are issues with how RMP's studies determine NEM program costs that include the incorrect attribution of administrative costs, lack of administrative cost data, and absence of evidence supporting distribution costs.[50] Mr. Stanley asserts that the Company does not account for the variable production of energy by the NEM program throughout the day and incorrectly relies on an exponential annual growth rate for NEM customers.[51] He

[45] *Id*., p. 10-11, lines 183-185 and 208-209.
[46] USEA Direct Testimony of Micah Stanley, pp. 3-4, lines 38-48.
[47] *Id*., p. 4, lines 61-63.
[48] *Id*., p. 5, lines 79-81.
[49] *Id*., pp. 6-7, lines 93-132.
[50] *Id*., pp. 7-8, lines 133-158.
[51] *Id*., p. 9, lines 159-160 and 165-167.

explains that the exponential growth of the NEM program predicted by RMP has been improperly used as justification for the expeditious implementation of the Company's rate proposal.[52] Lastly, Mr. Stanley states that RMP has incorrectly claimed that there are inherent profile differences between NEM and non-NEM customers caused by NEM customers exporting energy to the grid and consuming less energy.[53] He argues that the power generation by NEM customers does not lead to further use of RMP's resources and the profile of NEM customers, separate from the NEM program, is not dissimilar from that of a non-NEM customer who utilizes RMP's efficiency programs.[54]

E. HEAL

HEAL witness Jeremy Fisher examines RMP's cost of service studies ("CCOS") based on net power costs ("NPC"), evaluates avoidable energy elements omitted from the Company's analysis, seeks to quantify short-term and long-term DG system benefits not featured in RMP's assessment, and assesses cost-shifting.[55] There are several issues that HEAL finds with RMP's NEM analysis. Regarding the CCOS analysis, Mr. Fisher asserts the following: it illustrates only short-term energy benefits, uses an outdated renewable integration charge (from a 2012 study), does not account for all short-term avoidable costs (full variable cost of coal and existing coal plants' avoided variable operations and maintenance costs), does not account for avoided capacity benefits and

[52] *Id*., p. 9, lines 172-175.
[53] *Id*., p. 11, lines 199-201.
[54] *Id*., p. 11-12, lines 202-207.
[55] HEAL Utah Direct Testimony of Jeremy I. Fisher, p. 3, lines 11-18.

low-cost incremental procurement as determined in RMP's 2017 IRP, and the long-run cost-shift analysis is flawed.[56] Additionally, Mr. Fisher makes several findings regarding the Company's least or non-economic coal units. He asserts that if the Company's least-economic coal units were evaluated similarly to DG resources, these coal units would need above retail rates to be economically viable, impact ratepayers in excess of any DG attributed cost shifts, and have equal if not greater long-term losses than RMP's long-run cost-shift estimate.[57] Lastly, Mr. Fisher asserts that the CCOS analysis does not include the benefits derived from DG's contribution to emissions reduction and based on the estimated high-penetration of DG predicted by the Company, it can retire one or more non-economic coal units, without replacing any, that need selective catalytic reduction to be installed by 2021/22, which will lead to system cost savings.[58] Ultimately, Mr. Fisher concludes that the current NEM tariff does not need to be modified.[59]

F. Vivint Solar

Vivint Solar addresses the impacts of RMP's proposal on both residential solar customers and the solar industry in Utah, how the net metering tariff compares to particular ratemaking principles, grandfathering the net metering structure for current solar, and errors and incorrect assumptions it found in the ACOS, CCOS, and NEM Breakout analyses. Vivint Solar witness Thomas Plagemann evaluates the three parts of the rate structure proposed by RMP, which include an increased monthly fixed charge, a monthly

[56] *Id*., pp. 5-6, lines 6-26 and 1-7.
[57] *Id*., p. 6, lines 8-25.
[58] *Id*., pp. 6-7, lines 26-27 and 1-8.
[59] *Id*., p. 41, lines 7-9.

demand charge, and a reduced volumetric charge. He asserts that the three-part rate design proposed by the Company was similar to the rate structure introduced in Nevada that resulted in significant job losses within the solar industry and a "99% decrease in net metering applications year-over-year."[60] If the RMP proposal was accepted, he expects that Utah would experience a negative impact on the solar industry comparable to what occurred in Nevada with an estimated loss of "3,000-4,000 jobs" and several "associated downstream economic impact[s] to the state."[61]

Mr. Plagemann states that the high monthly fixed charge put forth by RMP discriminates against residential solar, which is no different than any other technology that reduces residential energy consumption, and does not take into account DG benefits both short-term and long-term.[62] He argues that the Commission should reject this type of discriminatory ratemaking and instead implement "a reasonable and small minimum bill for all residential customers" that encourages customers to reduce energy use and practice conservation and assures "some minimal level of cost recovery."[63] Mr. Plagemann considers the use of a demand charge for residential NEM customers unusual, since demand charges are generally only used in industrial and commercial ratemaking design due to these customers being "larger, with higher average peak usage, are more sophisticated, and are better equipped to manage such rate structures."[64] He asserts that

[60] Vivint Solar Direct Testimony of Thomas Plagemann, p. 3, lines 38-40.
[61] *Id*., pp. 12-13, lines 241-250.
[62] *Id*., p. 4, lines 54-57 and 62-64.
[63] *Id*., pp. 5-6, lines 85-89.
[64] *Id*., p. 6, lines 96-100.

the application of a demand charge for residential customers would need to at least: apply to all residential customers; be communicated and understood clearly by all residential customers; reflect the actual cost of interconnection or incremental costs of customer usage; and enable customers to manage their peak demand from accessible data.[65] Lastly, Mr. Plagemann explains that a reduced volumetric charge does not capture the short-term and long-term benefits provided by a residential solar system.[66] He finds that RMP's rate structure proposal not only ignores the long-term grid benefits of residential solar, it also eliminates consumer choice and discriminates against solar customers.[67]

Mr. Plagemann urges the Commission to reject RMP's proposal and support the use of gradualism in rate making design.[68] Additionally, he provides an alternative rate design that contemplates, under the current NEM program, grandfathering a meter for 25 years from the date RMP gives the customer permission to operate.[69] He further explains that there should be a small increase in the minimum bill for all residential customers and new residential solar systems would have a maximum offset percentage set at 90% of the prior 12 months of energy usage by the customer.[70] Lastly, a monthly true-up value for energy exports should be established as a step down rate that starts at the average retail rate and eventually reaches a rate floor and is based on solar penetration levels, which are

[65] *Id.*, pp. 6-7, lines 107-112.
[66] *Id.*, p. 8, lines 139-141.
[67] *Id.*, p. 9, lines 170-173.
[68] *Id.*, p. 13, lines 260-267.
[69] *Id.*, p. 14, lines 274-275.
[70] *Id.*, p. 14, lines 278-280.

determined by the percentage of total residential solar customers out of the total residential class.[71]

Vivint Solar witness Dan Black provides testimony supporting RMP's proposal to grandfather existing NEM customers. He asserts that the effectiveness of grandfathering hinges on its application being on the meter being located at the home where the solar system is installed, instead of being tied to an individual customer.[72] Mr. Black suggests that this is necessary to protect the value of a DG system, so when a home is sold, the grandfathering applies to the meter of the new buyer.[73] He recommends that grandfathering should occur for a system for at least 25 years, to allow the net metering customer enough time to recoup costs of and benefit from the investment.[74]

Additionally, Mr. Black explains that while rates can change, the current NEM program "must remain stable."[75] He further recommends that new customers coming online after the decision in this proceeding should be tied to the same rate structure that was in place when they made their solar system investment.[76] He recommends that if changes to the net metering program do occur under as a result of this proceeding, these changes should "not take effect for at least 90 days after the Commission's order is final."[77] He suggests

[71] *Id.*, p. 14, lines 281-285.
[72] Vivint Solar Direct Testimony of Dan Black, p. 1, lines 15-17.
[73] *Id.*, p. 1, lines 17-18.
[74] *Id.*, p. 2, lines 30-34.
[75] *Id.*, p. 3, lines 54-56.
[76] *Id.*, p. 7, lines 150-152.
[77] *Id.*, p. 7, lines 157-158.

that any customers who submit an application during the 90-day period should be grandfathered under existing net metering program, and applications submitted after would be part of the new NEM regime.[78]

Vivint Solar witness Richard Collins recommends that the results of RMP's cost of service study be rejected because of various errors and incorrect assumptions contained within the ACOS, Counterfactual Cost of Service ("CFCOS"), and NEM Breakout analyses.[79] He asserts that the issues with the cost of service analyses led to an underestimation of benefits and overestimation of costs relating to the NEM program.[80] Mr. Collins states that NEM customers should not be put under a different tariff or rate class.[81] Additionally, he asserts that "[b]ecause the Commission's required analytical framework fails to take into account the long-term benefits of a net metering program, it does not implement the Legislature's intent," and therefore the Commission should consider long-terms benefits and costs of the NEM program when deciding this proceeding.[82] Due to the errors made by the Company in its analyses, which cause concern about the impacts of costs and benefits of the NEM program, he recommends "the Commission make no or only incremental changes to the current residential net metering tariff."[83]

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[78] *Id*., p. 8, lines 161-166.
[79] Vivint Solar Direct Testimony of Richard S. Collins, p. 3, lines 52-55.
[80] *Id*., p. 3, lines 60-61.
[81] *Id*., p. 3, lines 64-66.
[82] *Id*., p. 4, lines 73-78.
[83] *Id*., p. 15, lines 318-322.

Mr. Collins further discusses the methodological errors in the Company's analyses. He first asserts that the Company is inappropriately trying to collect for lost revenues from behind-the-meter customer generators reducing consumption.[84] Then he suggests that the new meter cost calculation does not consider any benefits from redeploying old meters to other customers or alternatively offsetting the costs against a salvage value.[85] Other cost issues Mr. Collins addresses include using a fixed cost per hour for engineering and administrative functions and potential overestimation of NEM program billing costs.[86] He further asserts that there are multiple issues with the Company's NPC calculation: not all of costs associated with additional generation needed to replace power generated from residential NEM systems [were] included in the CFCOS; a system capacity value from the NEM program was not included by the Commission; and the integration adjustment was not appropriate.[87] One last issue Mr. Collins discussed was the Company's underestimation of rooftop solar's peak shaving ability.[88] Mr. Collins later presented two long-term, quantifiable benefits: renewable energy credits that the Company will not have to purchase; and avoiding future carbon reduction expenses.[89]

[84] *Id*., p. 16, lines 340-341.
[85] *Id*., p. 17, lines 364-367.
[86] *Id*., pp. 18-19, lines 385-391 and 397-402.
[87] *Id*., p. 23, lines 485-489.
[88] *Id*., p. 28, lines 590-595.
[89] *Id*., p. 39, lines 815-817.

Additionally, Mr. Collins addresses concerns about RMP's proposed rate design not following several important Bonbright ratemaking principles. The proposed residential net metering tariff does not promote the efficient use of resources and would devastate the solar industry within Utah, and the inclusion of a demand charge would make it hard to implement.[90] Further, there will not be revenue stability in the long-run because the demand charge will eventually incentivize customers to avoid it.[91] Overall, Mr. Collins recommends that the Company should be required to correct and resubmit its analysis or the recommended tariff revisions outlined in fellow Vivint Solar witness testimonies of Thomas Plagemann and Dan Black be adopted by the Commission.[92]

G. Vote Solar

Vote Solar evaluates several topics including RMP's request to separate residential solar rooftop customers into a new customer class, the Company's proposed rate design, the cost and benefit of residential DG resources, and suggested changes to the NEM program. Vote Solar witness Rick Gilliam demonstrates that separation of NEM customers into their own class has no basis because their load characteristics are similar to non-NEM customers.[93] He then asserts that RMP's proposed rate design is "inappropriate, discriminatory, and tantamount to a straight fixed-variable rate structure."[94] Mr. Gilliam presents two main issues with the rate design and recommends:

[90] *Id*., p. 34, lines 710-712 and 716-717.
[91] *Id*., p. 11, lines 226-227.
[92] *Id*., p. 3, lines 55-58.
[93] Vote Solar Direct Testimony of Rick Gilliam, p. 4, lines 64-67.
[94] *Id*., p. 4, lines 73-74.

rejecting the proposed demand charge structure; and rejecting the shift to cost recovery through a monthly customer charge because it does not follow proper ratemaking principles.[95] Next, he recommends that if the Commission modifies the current NEM program, it should adopt a principle of gradualism to protect NEM customers from adverse rate impacts.[96] Along with the concept of gradualism, Mr. Gilliam discusses three groups of NEM customers: current NEM customers; transitional solar customers; and future solar customers. He recommends the current NEM customers remain under the current NEM program structure, including "allowing for carry-forward of net excess energy to future months for a reasonable period of time" based on current investments made by these customers.[97] Mr. Gilliam defines the transitional solar customers as those who submit an application after the current NEM group is closed, and will be subject to monthly net billing that compensates excess generation at the end of the month at a rate tied to the total aggregate retail rate ("TARR").[98] Lastly, he discusses piloting of a long-term rate design. A TOU rate design is recommended, that can be refined and implemented in the recommended target year of 2025 for future solar customers and all residential customers in general.[99] Specifically, he recommends implementing "tiered energy rates within temporal blocks of a TOU structure commensurate with the tiered

[95] *Id*., p. 5, lines 79-85.
[96] *Id*., p. 5, lines 87-90.
[97] *Id*., pp. 5-6, lines 95-100.
[98] TARR is calculated as total residential revenue divided by total residential kilowatt-hour sales for the most recent calendar year and will decline over time as solar penetration increases. *Id*., p. 6, lines 101-108.
[99] Vote Solar Direct Testimony of Rick Gilliam, p.7, lines 121-131.

rate that exist[s] currently" to protect low-income customers not able to change their energy usage.[100]

Mr. Gilliam explains that the basis for RMP's proposal to segregate residential NEM customers into separate rate classes rests on several assertions that include: rooftop solar customers and other residential customers having different usage characteristics; the grid is utilized more by NEM customers because they import and export electricity; and peak solar generation does not coincide with the RMP's peak load.[101] However, he explains that the range of load factors for residential rooftop solar customers and non-solar residential customers do not significantly differ from each other.[102] Regarding grid usage by residential solar rooftop customers, he asserts that the exportation of excess generation from these customers has not been shown to seriously impact the grid, especially since RMP does not "manage" excess energy nor has it provided data supporting reverse flows.[103] Furthermore, any additional equipment needed to accommodate DG is paid for by the NEM customer and not the utility or other customers.[104]

Vote Solar witness David DeRamus presents similar conclusions that include finding that: costs are not greater than benefits of the NEM program; there is no reasonable basis to separate residential NEM customer into their own rate class; demand charges or

[100] *Id.*, p. 41, lines 820-824.
[101] *Id.*, p. 15, lines 316-320.
[102] *Id.*, p. 17, lines 346-347.
[103] *Id.*, p.19, lines 377-382.
[104] *Id.*, p.19, lines 392-393.

increased fixed monthly charges have not been reasonably based; and any modifications to the NEM program should be made gradually and only to the compensation credit for excess generation exports.[105] He further asserts that the export credit value should be reevaluated periodically through a separate process.[106]

In support of his conclusions, he argues that although RMP claims the costs of the current residential NEM program outweigh the benefits, this interpretation is incorrect and is based on inadequate data and analysis.[107] He then argues that the Company's claim that NEM customers may add costs associated with reverse flows is not supported by evidence showing that these flows cause additional costs.[108] In fact, he suggests that reverse flows would produce a benefit by reducing both peak demand on the system and loading on transformers and distribution circuits.[109] Further, he suggests that RMP's claims that there is a cost associated with the sales revenue foregone because of residential NEM customers' consumption of their own generation should not be considered an increase in costs, especially since revenue reductions tied to energy efficiency "are never treated as a cost of service."[110] When considering benefits of DG that RMP incorporated, Dr. DeRamus argues that the Company discounts the value of export generation and ignores the many long-term benefits associated with DG, while

[105] Vote Solar Direct Testimony of David W. DeRamus, p. 3, lines 48-55.
[106] *Id.*, p. 3-4, lines 55-58.
[107] *Id.*, p. 4, lines 61-62.
[108] *Id.*, p. 4, lines 64-66.
[109] *Id.*, p. 4, lines 66-69.
[110] *Id.*, p. 4, lines 69-74.

only considering avoided line losses and the avoided cost of generation and purchases.[111] He then describes other benefits provided by residential DG that are ignored by RMP, which include grid resiliency, reliability, capacity, and environmental benefits.[112] Further, he explains that the excess energy provided by NEM customers benefits the system by serving the load of nearby customers, especially during peak loads.[113] Lastly, he asserts that DG will provide a net benefit to customers when appropriately valued.[114]

Dr. DeRamus then observes that RMP is seeking to implement a three-part rate design for residential NEM customers that contains an increased monthly fixed customer charge, a demand charge, and a reduced energy rate. While the Company argues that this rate structure will prevent cost-shifting from residential NEM customers to non-NEM customers, he posits that its main concerns are an increase in the Company's risk of under-recovery and limiting the development of its asset base.[115] However, Dr. DeRamus argues that these new charges combined with lower energy rates do not incentivize customers to reduce consumption, adopt supplementary energy efficiency measures, or switch their usage from high to low demand time periods.[116]

Dr. DeRamus has several similar recommendations for the Commission regarding NEM compensation and rate design. He recommends that the Commission adopt a principle of

[111] *Id.*, p. 4, lines 76-79.
[112] *Id.*, p. 4, lines 80-81.
[113] *Id.*, p. 5, lines 94-95.
[114] *Id.*, p. 5, lines 83-84.
[115] *Id.*, pp. 5-6, lines 106-110.
[116] *Id.*, p.6, lines 113-116.

gradualism if they decide to modify the NEM program, and limit any change of the current NEM program to the export credit or the crediting mechanism, which should consider changes in DG costs and benefits over time, the deployment of complementary technologies, and changes in the state's energy mix and grid management concerns.[117] Lastly, he suggests implementation of TOU rates for all residential customers because they encourage customers to shift their load, which could lead to a reduction in RMP's need for system investments.[118]

<u>H. EFCA</u>

EFCA witness Eliah Gilfenbaum addresses the topics of cost-shifting, the Company's cost of service studies, and the valuation of energy exports. He begins his testimony by arguing that the alleged amount of cost-shifting caused by residential NEM customers is very small compared to the cross-subsidization that currently exists due to the Company collecting revenue that greatly exceeds the cost of service for all classes.[119] He maintains the overearning experienced by RMP, and any issues with cross-subsidization, could be rectified through a general rate case to readjust revenues.[120] However, the Company has decided not to use a general rate case to address such issues he notes.

The COS analyses conducted by RMP consists of three studies: the CCOS; ACOS; and NEM Breakout COS. Although Mr. Gilfenbaum agrees that these studies provide

[117] *Id*., p.6, lines 121-128.
[118] *Id*., pp. 6-7, lines 128-132.
[119] EFCA Direct Testimony of Eliah Gilfenbaum, p. 4, lines 67-70.
[120] *Id*., pp. 4-5, lines 87-90.

meaningful and pertinent information, he points out several issues with these analyses. One issue he points to is the use of only a single historical test year in the analysis, which makes it impossible to assess the long-term benefits of a resource.[121] Additionally, he notes the COS studies do not differentiate between the generation consumed onsite by NEM customers and the value of energy they export, which could lead to excessively broad policy changes that impact self-generation rights.[122] After excluding the credit for exports, Mr. Gilfenbaum compares the theoretical revenue derived from customers who are billed based on delivered load to the full cost to serve that load, finding that residential solar customers contribute 91.6% of their cost of service without changes to assumptions and calculations in the Company's studies.[123]

Mr. Gilfenbaum questions the basis for allocating distribution line transformer costs, arguing that the July NCP should be used to allocate line transformer costs for residential NEM customers and not the December NCP. He finds that this change would result in having a $209,872 lower allocation of line transformer costs being charged to the residential NEM class.[124] Regarding the coincidence factor involved in line transformer cost allocation, the lower numbers of NEM customers per transformer is due in his view to the pervasiveness of single-family homes in this portion of the residential class and not because these customers have solar rooftop systems.[125] He found that the Company's

[121] *Id*., p. 6, lines 117-119.
[122] *Id*., p. 9, lines 184-189.
[123] *Id*., p. 12, lines 239-243.
[124] *Id*., p. 14, lines 281-285.
[125] *Id*., p. 15, lines 299-305.

calculated coincidence factor for broken out NEM customers is based on an estimate that there are less customers per transformer among NEM customers than for the residential class in general.[126] Although this difference in customers per transformer signifies that transformer load diversity decreases if the customer has a solar system, this is an incorrect interpretation he maintains.[127] He counters that solar customers would most likely increase load diversity, resulting in a lower coincidence factor.[128] Mr. Gilfenbaum demonstrates that by changing from the December NCP to the July NCP, or using the residential class average coincidence factor of .76 for the NEM group of customers, can lead to a COS parity that is on par with the residential class in the ACOS study.[129] Based on these findings, he does not support the Company's arguments for creating a separate residential NEM rate class.[130]

Regarding the valuation of exported energy, Mr. Gilfenbaum argues that the Company has not fully captured the value of exported energy.[131] In particular, he suggests the Company has neglected to evaluate the additional benefits derived from the following: "long-run energy; losses and CO_2 value; avoided generation capacity; and avoided transmission and distribution ("T&D") costs."[132] Using data from the Company's IRP for his analysis, Mr. Gilfenbaum calculated the numerous benefits and costs associated with

[126] *Id*., p. 16, lines 326-329.
[127] *Id*., p. 17, lines 334-338.
[128] *Id*., pp. 17-18, lines 338-342.
[129] *Id*., pp. 18-19, lines 343-344 and 370-372.
[130] *Id*., p. 19, lines 378-379.
[131] *Id*., p. 21, lines 423-424.
[132] *Id*., p. 22, lines 438-440.

each of the previously stated categories, and when data was not available he used standard industry approaches to calculate marginal costs, such as avoided T&D marginal costs.[133] Summing these benefits and costs gives a long-term levelized value of NEM energy exports of $0.1257/kWh, which is larger than the average exported kWh credit amount of approximately $0.106/kWh.[134] The analysis of these values presented, shows that there are significant benefits generated by NEM systems and facilities in the long-term, which are not captured by the analytical methodology used by RMP.[135] Based on this analysis, Mr. Gilfenbaum recommends that "the Commission consider additional perspectives to inform its long-term consideration of customer-sited generation and other distributed generation energy resources".[136]

I. OCS

The OCS covers several topics, including the COS studies, RMP's proposal for new rates and tariffs, and the net metering cap. Additionally, the OCS submits several proposals that include a suggested sustainable successor rate design, a transition plan, and a communications plan. Regarding RMP's COS studies, the OCS agrees with the Company that they show the load shapes and usage characteristics between residential DG and non-DG customers are uniquely different and that the current NEM program creates a net cost to the Company's system due to non-NEM customers subsidizing the NEM customers.[137]

[133] *Id.*, p. 24, lines 479-481.
[134] *Id.*, p. 24, lines 485-489.
[135] *Id.*, p. 45, lines 840-842.
[136] *Id.*, p. 45, lines 838-840.
[137] OCS Direct Testimony of James W. Daniel, p. 6, lines 146-153.

However, the OCS considers cost-shifting between NEM program customers and non-NEM customers to be an emerging issue that can be better evaluated during the next rate case or when DG penetration reaches "a critical point".[138]

The OCS also asserts that the use of a 2015 test year in RMP's COSS analysis is inadequate for creating new rates, that updating the 2015 COSS for one modification, and a separate residential NEM class with its own rate, constitutes "piecemeal ratemaking."[139] Besides arguing against establishing a new NEM rate class and corresponding new schedules (Schedules 5 and 136), the OCS asserts that the Company has "not adequately considered customer impacts caused by its proposed Schedule No. 5" and would like the Commission to consider a bill impact analysis comparing what new NEM customers would pay under the proposed and current NEM programs.[140] Further, OCS witness Daniel argues that RMP did not properly consider a TOU rate design for its proposed Schedule No. 5 and the Company's proposed deferral account offer "to capture differences in revenues from new DG residential customers" should be rejected.[141]

The OCS further evaluates RMP's proposed net metering rate design, particularly the customer charge and the net metering application fee. OCS witness Danny Martinez argues that the proposed customer charge is "excessive and includes costs not previously

[138] *Id*., p. 6, lines 153-158.
[139] *Id*., p. 6, lines 163-167.
[140] *Id*., p. 9, lines 219-228.
[141] *Id*., p. 15, lines 391-395.

prescribed or approved by the Commission to be included in a residential customer charge."[142] Mr. Martinez recalculated the customer charge by starting with "the Commission's customer charge calculation method," but then adding "some FERC[143] accounts directly related to meter and service drops along with customer accounts currently not included in the Commission Method."[144] Additionally, he explains that transformer costs should be excluded from the customer charge "since they are not directly related to costs of net plant for service lines or meters, customer billing, and meter reading."[145] Further, he states that the customer charge should not collect costs shared by multiple customers.[146] Lastly, he explains that "[f]unctionalized miscellaneous costs are not directly associated with customer billing, metering, and net plant (service lines and meters) and thus do not belong in the customer charge."[147] Mr. Martinez's calculations result in a residential NEM customer charge of $8.50.[148]

Regarding NEM customer application fees, the OCS supports RMP's proposal to increase the base fee for Level 1 applications from "$0 to $60 with no increase in the per kW fee," but asserts that the Level 2 and Level 3 application fees should remain the same until the Company can adequately justify why they should increase.[149] Additionally, the OCS

[142] OCS Direct Testimony of Danny A.C. Martinez, p. 2, lines 58-60.
[143] Federal Energy Regulatory Commission ("FERC").
[144] *Id.*, p. 3, lines 69-74.
[145] *Id.*, p. 7, lines 198-200.
[146] *Id.*, p. 8, lines 207-208.
[147] *Id.*, p. 8, lines 214-216.
[148] *Id.*, p. 8, lines 222-225.
[149] *Id.*, p. 9, lines 253-258.

supports RMP's request for the Commission to "[g]rant a waiver of R746-312-13(a)" and to "[c]onsider whether a formal rulemaking proceeding should be initiated to review R746-312-13 on a longer term basis."[150]

The OCS makes some additional recommendations and proposes a new rate design. First, the OCS recommends the Commission reject the Company's proposed Schedule 5 and Schedule 136.[151] Next, the OCS states that a separate customer class is not necessary and its new rate design proposal will not require one.[152] OCS witness Michele Beck explains that the new rate design will require TOU rates "for consumption and a separate compensation rate for excess energy (determined hourly or more frequently)."[153] Further, the OCS is recommending the Commission approve a new, lower NEM program cap.[154] While the OCS is against the creation of an unjustified rate design for new NEM customers, it does agree that RMP's COSS shows net metering is not a feasible long-term rate design.[155] Therefore, the OCS proposes that the Commission set a cap for the level of NEM resource penetration, preferably closer to a penetration level of 10%.[156] Lastly, the OCS is recommending that the Commission "approve a transition plan that includes a rate design solution to grandfather the rate design for net metering customers for a time limited period and a phased-in compensation rate for excess energy for new, post net

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[150] *Id*., p. 13, lines 370-376.
[151] OCS Direct Testimony of Michele Beck, p. 4, lines 78-79.
[152] *Id*., p. 4, lines 72-74.
[153] *Id*., p. 5, lines 95-98.
[154] *Id*., p. 5, lines 93-94.
[155] *Id*., p. 12, lines 252-253.
[156] *Id*., p. 15, lines 323-324.

metering DG customers" and "incorporate a communication plan" to educate customers.[157]

The OCS proposes an alternative rate design for this docket that seeks to properly compensate NEM customers for their energy exports while also ensuring that they pay an adequate amount of utility system costs.[158] The new tariff rate would measure excess energy on an hourly or smaller, appropriately metered interval, with customer bills being credited for the "dollar value of excess energy, with bill credits that expire at the end of the annual period," which eliminates netting within the billing period.[159] Under this proposed tariff, customers are required to participate in a TOU rate to receive compensation.[160] Lastly, the monthly customer charge would include an adder to recover the costs related to additional metering requirements.[161] The OCS expects this new rate design to be implemented after the Company's next general rate case, when new rates become effective.[162] Regarding the compensation rate, the OCS recommends "developing a compensation rate using similar methodology to what is used in developing Schedule 37."[163]

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[157] *Id*., p. 5, lines 99-105.
[158] *Id*., p. 16, lines 353-355.
[159] *Id*., p. 17, lines 368-376.
[160] *Id*., p. 17, lines 377-378.
[161] *Id*., p. 18, lines 381-382.
[162] *Id*., p. 18, lines 384-385.
[163] *Id*., p. 19, lines 406-407.

A transition plan is put forth by the OCS to help support a post net metering rate design. The proposed transition plan would establish a transition period of about twelve years to grandfather NEM customers and phase in a new excess energy compensation rate.[164] Current NEM customers would be allowed to switch to a post NEM rate structure.[165] NEM customers would have to pay a facilities fee based on the installed kW to properly collect costs to serve those customers.[166] A process would be initiated to develop a new compensation rate for excess energy with an hourly or sub-hourly definition of exported energy.[167] The compensation rate for exports would be changed from a set dollar design to a formulaic rate with other new rates, including a TOU rate, being set in a new general rate case.[168] Finally, a new NEM cap would be created to match the expected level of DG installed at the time of the next general rate case or January 1, 2020.[169] Additionally, the OCS proposed a communications plan to support the transition plan.

J. UAE

UAE argues that RMP did not sufficiently demonstrate that changes to the net metering program for Schedule 6 and 8 customers are warranted and therefore the Commission should not accept the Company's proposal.[170] According to UAE, the Company's proposal does not satisfy the Utah law requirement that charges and credits be deemed

[164] *Id*., p. 26, lines 571-573.
[165] *Id*., p. 26, lines 574-575.
[166] *Id*., p. 26, lines 576-579.
[167] *Id*., p. 27, lines 586-588.
[168] *Id.*, p. 27, lines 591-592 and 600.
[169] *Id.*, p. 28, lines 618-620.
[170] UAE Direct Testimony of Phillip J. Russell, p. 2.

just and reasonable "in light of the costs and benefits" associated with the net metering program.[171] Under Utah Code § 54-15-105.1 (the "NEM Statute"), two subsections dictate that the Commission will determine if the net metering program costs exceed the benefits, or vice versa, and in light of cost and benefits, determine charges, credits, or any rate structure of the net metering program that are just and reasonable.[172] UAE states that RMP's proposal is contrary to the NEM Statute because for Schedule 6 and 8 net energy metered customers the Company seeks to increase charges and decrease credits for reasons that are not backed by or connected to the cost and benefits shown for these customers.[173]

Additionally, UAE contends that RMP's data actually shows lower rates under the current net metering program for other Schedule 6 and 8 customers and the claimed benefits exceed claimed costs for those classes.[174] In a comparison of the cost of service studies included in the Company's Compliance filing, UAE explains that the foregone revenue tied to behind-the-meter consumption of privately generated energy should not be treated as a cost of net metering.[175] UAE explains this is an incorrect assumption because there is no evidence that offsetting part of a NEM customer's load from behind-the-meter generation causes an increase in the cost of serving the NEM customer.[176]

[171] *Id*., p. 3.
[172] *Id*.
[173] *Id*., p. 5.
[174] *Id*.
[175] *Id*., p. 7.
[176] *Id*., p. 8.

Further, the Company's own evidence shows that NEM customers subsidize non-NEM customers under the current NEM program because Schedule 6 and 8 customers paid a higher percentage of the costs to serve them than did non-NEM customers.[177] Since as UAE maintains, data from RMP's Compliance filing shows how the benefits of the currently constructed net metering program exceed the costs with respect to Schedule 6 and 8 customers, RMP's proposal to make revisions for Schedule 6 and 8 customers should be denied as these changes are not "in light of the cost and benefits" of the net metering program under the NEM Statute.

UAE's final argument is that RMP's proposal to eliminate the Average Retail Rate Option for new customers should be rejected, especially since the Company fails to address the concerns that necessitated the creation of this rate or demonstrate how the proposal will secure fair compensation for excess generation.[178] UAE explains that while RMP shows that the Average Retail Rate Option leads to a higher credit amount than the other crediting options, the Company does not supply clear justifications for why this option should be removed.[179] Further, UAE asserts that the Average Retail Rate Option undervalues Schedule 6 and 8 customers' excess generation because the current NEM program leads to high costs for NEM customers and lower costs for non-NEM customers.[180]

[177] *Id*., p. 14.
[178] *Id*., pp. 16-18.
[179] *Id*., pp. 18-19.
[180] *Id*., p. 19.

III. ISSUES AND ANALYSIS

A. Response to Analyses of NEM Costs and Benefits

Q. Please describe your testimony in this section.

A. Herein, I describe arguments made by certain intervenors which are notable, pertinent to the Company's compliance filing and with which I either partially to fully agree or disagree.

However, silence on any particular finding, argument, or recommendation by a party should not necessarily be interpreted as agreement by either Division Staff or myself.

Q. Have other intervenors criticized RMP's quantification of NEM costs and benefits?

A. Yes. As described in my summaries above, many parties argue that RMP has underestimated NEM benefits. A common theme is that RMP has not properly evaluated NEM benefits on a long-term horizon, and therefore not accounted for long-term avoided cost savings from avoided energy, generation capacity, and transmission and distribution investment.

Q. Do you agree with the intervenors' arguments?

A. I agree that generation resources are best evaluated over a long-term horizon because they are long-term investments. Utility resource planning is typically performed over a horizon of 10-20 years or more, and the typical objective is to forecast which types of generation resources meet customer needs over time at the lowest cost. PacifiCorp's Integrated Resource Plan, for instance, presents just such a long-term analysis.

However, none of the intervenors attempt to show that distributed solar generation is the resource that meets demand at lowest-possible cost. Importantly, they do not compare distributed solar generation to utility-scale wind and solar, but instead compare distributed solar generation to fossil fuel-based resources. If, under an appropriate analysis, it was found that a utility-scale renewable energy project could provide similar benefits when compared to fossil-fired generation, but at a lower cost, it would likely be preferred over distributed solar generation.

Q. How do the benefits of utility-scale solar compare to those of distributed solar?

A. Both provide a reliable source of emission-free, green energy. Utility-scale projects typically have advantages of using technology that can better track the sun and produce higher capacity factors than a typical fixed tilt rooftop system. Utility-scale solar is typically sited in more optimal locations for generation, generally in Utah at lower latitudes. Utility-scale projects also typically come with performance guarantees and provide utilities with more control over the generation, which makes it a more reliable source of capacity than a distributed system controlled by a customer.

At the same time, distributed solar has locational advantages over utility-scale projects due to its proximity to load. This can avoid energy losses, the need for transmission to interconnect centralized generation with distribution circuits, and potentially even some distribution costs, depending on the location and size of the systems. It also has environmental siting advantages in that rooftop systems are on previously-developed land.

Q. How do the costs of utility-scale solar and distributed solar compare?

A. Economies of scale and higher capacity factors typically yield significantly lower levelized costs for utility-scale systems. For example, RMP claims it can acquire wholesale utility-scale solar for less than $0.04/kWh.[181]

Q. What renewable energy technologies besides solar are also available at lower costs on the utility-scale and were not considered by intervenors in their cost-benefit analyses?

A. There are several, but those most-applicable to PacifiCorp's system are large wind farms and large hydro dams. For example, RMP is proposing "to construct or acquire approximately 860 MW of new wind projects and construct the transmission projects" that it asserts will lower the net power costs and produce renewable energy credits that once sold in the market can lead to lower costs for customers, as well as lead to further decarbonization of the Company's portfolio.[182] Additionally, the Company could add utility-scale storage in the future, which would provide better overall grid reliability than small clusters of DG customers located throughout the distribution system.

[181] Direct Testimony of Gary W. Hoogeveen, p. 17, lines 354-355.
[182] Docket No. 17-035-40, Direct Testimony of Rick T. Link, p. 3, lines 40-41 and 46-53.

Q. Given the cost advantages of utility-scale projects, do you foresee distributed generation having any value in Utah's future electric system?

A. Yes. I expect distributed generation will still play a significant role in Utah's electric grid for multiple reasons. First, customers should always have the ability to meet their own load with their own generation if they so choose. Based on their own values, customers may still choose to build and own solar, even if utilities can supply renewable power at much lower costs than they do today. This is especially true in a future where distributed solar systems are paired with low-cost battery storage to allow a customer to supply its own energy even when it loses power from the grid. However, the future is not yet here and only the customer can appropriately gauge such reliability benefits' worth.

Second, despite the typical cost advantages of utility scale projects at the generation level, it is still possible for distributed solar to have higher net benefits than utility solar. This is especially true in cases where there is a lack of good utility solar sites, where utility solar requires high transmission interconnection costs, and when right-sized, distributed solar can avoid some distribution costs.

Q What do you recommend regarding the comparison of utility-scale and distributed renewable generation?

A. I recommend the following:

- Customers should not be forced to pay a much higher cost for distributed solar from their neighbors if the utility can offer it at a much lower cost from large projects - after factoring in generation, transmission and distribution costs associated with utility-scale projects.
- Nevertheless, utilities should not overlook distributed generation as an important potential resource in their system planning, especially when ratepayers and society realize measurable and verifiable avoided cost benefits to the system.
- Customers who receive service from the grid, regardless of whether they also supply some of their own generation, pay an appropriate cost-based rate for that service.

These recommendations apply to all utilities in all states, including RMP in Utah. As long as these recommendations are met, customers and utilities should be able to find the right balance of distributed and utility-scale projects that respect customer choice while maximizing net benefits of renewable power.

Q. Do you have any additional issues with the intervenors' analyses of the benefits of solar?

A. Yes. For example, EFCA presents its own analysis of the value of solar, and I do not agree with all the assumptions in its analysis. I describe my concerns below.

- EFCA breaks with RMP's IRP assumptions by assuming a Resource Balance Year of 2021 instead of 2028.[183] I have not conducted an independent analysis of

[183] EFCA Direct Testimony of Eliah Gilfenbaum, p. 31, lines 595-597.

RMP's IRP assumptions, but such a planning exercise is always subject to uncertainty. Instead of attempting to update an IRP in estimating the value of solar, I recommend including distributed solar generation as a resource in the IRP, perhaps in a well-constructed with-and-without analysis. This best captures DG's costs and benefits compared to all relevant generation alternatives, including utility-scale projects as discussed above.

- EFCA grosses up its estimate of avoided capacity cost by 13%, an amount equal to RMP's planning reserve margin.[184] This supposedly reflects that from a utility planning perspective, distributed solar acts as a load reduction, which can therefore avoid the need for planning reserves. I disagree with this assertion. Planning reserve margins are required to ensure system reliability in the case of generation forced and planned outages. Distributed solar generation also has outages that a utility must plan for. In fact, utilities have little control over solar generation assets owned by their customers. Such assets may be taken offline for any number of reasons, such as technical failure, damage to the panels, and planned construction projections at the home or business. At high penetrations of solar energy, sudden cloud cover could even become a contingency requiring special consideration in utility planning and the need for additional reserves. Meeting load with solar is not equivalent to not placing any load on a system and they should not be treated the same way.

[184] EFCA Direct Testimony of Eliah Gilfenbaum, p. 37, lines 705-707.

- EFCA estimates a value of avoided transmission cost of $0.0294/kWh based on a regression analysis.[185] On its face, this value seems unreasonably high given that the embedded cost of transmission based on RMP's allocated COS study is $0.016/kWh for the residential class. The value is likely too high for two reasons. First, I recommend a lower carrying charge rate for transmission assets. EFCA used a value developed for a new combustion turbine ("CT"), [186] and I expect transmission assets will have longer lifetimes than a CT, which would lead to a lower carrying charge all else being equal. Second, it relies only on a regression analysis and not any specifics of avoided costs of any transmission projects. I expect there will still be need for growth in transmission investment even in a future with high amounts of distributed solar generation. Significant transmission costs will still be necessary to transmit power from generation assets that generate when the sun does not shine, including other green power such as wind and hydro.[187] Please refer to Division witness Dr. Powell's testimony for additional critiques of the regression-based approach used by EFCA in its long-term transmission benefit analysis.
- EFCA estimates a long-term distribution capacity value of $0.0178/kWh, also based on a regression analysis.[188] I do not agree there is any one avoided distribution cost that would apply to all distributed solar generation. The potential

[185] EFCA Direct Testimony of Eliah Gilfenbaum, p. 43, lines 810-816.
[186] EFCA Direct Testimony of Eliah Gilfenbaum, p. 42, lines 791-796.
[187] Docket No. 17-035-40, Application for Approval of a Significant Energy Resource Decision and Voluntary Request for Approval of Resource Decision, where the Company is seeking to construct or procure 860 MW of wind from Wyoming and construct multiple transmission projects. Direct Testimony of Rick T. Link, pp. 2-3, lines 34-44.
[188] EFCA Direct Testimony of Eliah Gilfenbaum, p. 44, lines 827-832.

variation is so wide, it cannot be reasonably ignored. For example, distributed solar generation with minimal power exports on circuits with high loads compared to distribution system capacity may provide a significant distribution avoided cost benefit. In contrast, distributed generation systems that export large amounts of power on circuits saturated with solar power can require distribution system upgrades to safely interconnect. While interconnection costs borne by the solar customer can offset some of these upgrade costs, there are likely to be increased marginal distribution system investments required due to solar saturation that cannot be assigned solely to the newly interconnected customer for practical or other reasons.

Q. You stated above that some of the intervenors relied on data from the Company's 2017 IRP. Briefly explain how the IRP data was used.

A. UCE witness Woolf uses the IRP as an example of a cumulative present value of revenue requirements ("PVRR") analysis, which is used to identify if a resource will result in net costs or net benefits to customers, because it compares electricity resource portfolios with alternative portfolios.[189] Mr. Woolf further asserts that the "Company's most recent IRP estimates the net benefits of different levels of distributed generation on its system".[190] Vivint Solar witness Collins makes similar claims to Mr. Woolf regarding the PVRR showing long-term benefits of DG.[191] He further argues that the IRP shows a higher solar

[189] UCE Direct Testimony of Tim Woolf, p. 15, lines 276-282.
[190] UCE Direct Testimony of Tim Woolf, p. 25, lines 466-467.
[191] Vivint Solar Direct Testimony of Richard Collins, pp. 9-10, lines 194-197.

capacity contribution, the peak demand reduction shown in the IRP reduces the subsidy from non-NEM customers, and using a proxy price from the 2015 RMP IRP for the unbundled REC price in Utah leads to quantifiable REC benefits.[192]

Vote Solar witness DeRamus uses the 2015 and 2017 IRPs to make similar claims about how distributed generation can help reduce T&D investment due to benefits from reduced load.[193] He further discusses the benefit of peak capacity reduction, which was not included in the COS studies.[194] Lastly, Dr. DeRamus uses the 2015 and 2017 IRPs to determine avoided CO_2 compliance costs.[195]

HEAL witness Fisher uses the IRP to argue that the Company's COSS analysis failed to take into account avoided capacity benefits and incremental low-cost procurement, both of which he claims are shown as benefits from distributed generation.[196] Mr. Fisher further uses the IRP as a means to compare distributed generation resources to the Company's least-economic coal units.[197]

EFCA witness Gilfenbaum uses the IRP data that was available to determine a long-term value of energy exports for NEM facilities located on the Company's system.[198]

[192] Vivint Solar Direct Testimony of Richard Collins, pp. 31, 32, and 39, lines 644, 679-683, and 828-830.
[193] Vote Solar Direct Testimony of David W. DeRamus, pp. 55and 66, lines 1090, 1096-1097, 1275, and 1280-1281.
[194] Vote Solar Direct Testimony of David W. DeRamus, pp. 66-67, lines 1291-1293.
[195] Vote Solar Direct Testimony of David W. DeRamus, p. 68, lines 1326-1329.
[196] HEAL Direct Testimony of Jeremy I. Fisher, pp. 5-6, lines 19-26 and 1-2.
[197] HEAL Direct Testimony of Jeremy I. Fisher, p. 6, lines 8-25.
[198] EFCA Direct Testimony of Eliah Gilfenbaum, p. 24, lines 479-489.

Q. Do you agree with the use of the Company's 2017 IRP as a source for calculating NEM costs and benefits?

A. No. Using the Company's IRP analysis to calculate the value of NEM costs and benefits is inappropriate. This is especially true since the Company filed its 2017 IRP earlier this year and the IRP is still being reviewed and vetted to determine if it is reasonable. Additionally, the IRP is subject to modifications during the review process that could lead to updates to initial data and scenario analyses, and costs and benefits of alternative resource portfolios will indeed change over time. As Mr. Woolf notes, the IRP does an energy portfolio analysis that compares alternative options. However, the IRP process is a more integrated planning process that considers several factors in determining a PVRR for a resource plan at a given time, which is only partially comparable to a longer-term benefit-cost analysis needed to incorporate values of benefits and costs of the net metering program that do not accrue within the Company's test year.

It is notable that the Company has not attempted to directly value the benefits and costs of DG in its last IRP. As described by the Company in its 2015 IRP:[199]

> The major difference in the treatment of DG in the 2015 IRP is the application of DG as a reduction to load. The Navigant study identifies expected levels of customer-sited DG. The DG is then netted against the IRP load forecast rather than being selected as a utility resource. This methodology more accurately reflects drivers behind DG penetration, which is customer economics, not utility economics.

[199] Docket No. 15-035-04, PacifiCorp 2015 IRP, Volume I, p. 72.

Therefore, due to the more integrated planning and analysis nature of the IRP, the fact that there is no direct valuation of the costs and benefits of DG specifically included in the IRP, as well as the fact that the proceeding to review it is still open and therefore the IRP is subject to change, I do not believe it should not be considered a reliable resource used to calculate long-term costs and benefits of the Company's NEM program.

Q. Do you have any other comments about NEM costs and benefits?

A. Yes. Vivint Solar witness Black recommends that grandfathering should occur for a system for at least 25 years, to allow the net metering customer enough time to "recover and benefit from their investment."[200] I disagree with this notion of the need for grandfathering. Grandfathering is meant to lessen the burden of a wholesale change in rate structure, rates, or a program on all ratepayers, not to ensure they receive the all benefits they thought they were getting when making an investment. Such a guarantee would exceed the standard for utilities with regard to the "opportunity" to earn a fair return on rate-based investments.

B. <u>COS Analysis</u>

Q. What issue did you have with Vote Solar witness DeRamus' and Vivint Solar witness Collins' analyses of RMP's Counterfactual COS Study?

[200] Vivint Solar Direct Testimony of Dan Black, p. 2, lines 30-34.

A. I disagree with how Dr. DeRamus and Mr. Collins characterize bill credit “costs” in the counterfactual COS (“CFCOS”) study. Both witnesses claim that RMP should not have included lost revenues due to solar generation consumed onsite as a “cost” in the CFCOS study. They state that RMP does not attempt to recover “lost revenue” from customers who reduce loads from energy efficiency investments and that behind-the-meter consumption by NEM customers should not be treated any differently.[201] Reducing the “cost” of bill credits to include only lost revenues from exported energy decreases the net cost of NEM for residential customers from $1.7 million to $357,000.[202]

Q. Why do you disagree with this characterization?

A. Under traditional utility ratemaking, a utility is not entitled to recover “lost revenues,” but it is entitled to recover its prudently-incurred costs. If a utility had been earning its revenue requirement and then its revenues decline more than its costs decline over the same period, it can request a rate increase. The point of the CFCOS study, as I understood it, was to compare RMP’s costs and revenues under two scenarios: one as actually occurred and one with *no* distributed generation. Thus, in the counterfactual scenario all solar output was excluded, both what was exported and consumed onsite. RMP’s methodology to consider all revenue reduction from all solar generation therefore seems appropriate. By only removing the lost revenues from onsite generation without any adjustment to the avoided costs, Dr. DeRamus and Mr. Collins essentially assume

[201] Vote Solar Direct Testimony of David W. DeRamus, p. 32, lines 658-664; Vivint Solar Direct Testimony of Richard S. Collins, p. 16, lines 346-353.
[202] Vote Solar Direct Testimony of David W. DeRamus, p. 32, lines 655-657.

that a utility can achieve reduced net power costs from reduced load without any loss of revenues, which does not make sense.

One may also wish to analyze scenarios with and without only exported energy in order to value that exported energy, but that is simply a different analysis, and neither witness has presented the results of such an analysis.

C. <u>Netting and Crediting</u>

Q. How do the intervenors address netting of consumption and generation?

A. Several of the intervenors support monthly netting and carry over of excess generation under the current NEM program, which rolls excess kWh generated at the end of a month into the next month, and so on, until an annual cash-out occurs for any excess kWh remaining. Some intervenors specifically address changes to the current monthly netting process moving forward, as discussed below.

Vote Solar witness Gilliam explains that several parties are concerned about seasonal impacts of carrying over net excess generation from month to month.[203] Even though he does not believe this is currently an issue, he proposes "to allow netting of energy only within the billing period and any net excess generation that remains after such netting be compensated at a rate that recognizes the value of excess energy."[204] Fellow Vote Solar

[203] Vote Solar Direct Testimony of Rick Gilliam, p. 36, lines 746-748.
[204] Vote Solar Direct Testimony of Rick Gilliam, pp. 36-37, lines 752-758.

witness DeRamus agrees that as solar DG penetration increases, a monthly netting process will address seasonal concerns instead of "crediting exports to future months on a kwh-for-kwh basis over the year."[205]

The OCS is proposing a post net metering rate design that would measure excess energy at hourly or smaller intervals, which would lead to the "elimination of netting within the billing period."[206] Further, excess energy would be credited to customer bills based on the dollar value of that energy, and like the current NEM program design, bill credits would "expire at the end of the annual period."[207] In support for this change, the OCS explains that "it will be extremely difficult or impossible to assign costs correctly while maintaining netting across the billing period," without creating intra-class subsidies between NEM and non-NEM customers.[208]

Contrary to the post net metering design put forward by the OCS, UCE does not support changing the current monthly netting process to netting on an hourly basis due to potential "dramatic" customer bill impacts, as well as the possible undermining of "the economics of solar in a similar manner to the Company's proposed Schedule 5."[209] Further, UCE asserts that based on the hourly load profile of a customer, hourly netting

[205] Vote Solar Direct Testimony of David W. DeRamus, p. 80, lines 1585-1592.
[206] OCS Direct Testimony of Michele Beck, p. 17, lines 368-370.
[207] OCS Direct Testimony of Michele Beck, p. 17, lines 374-376.
[208] OCS Direct Testimony of Michele Beck, p. 22, lines 485-488.
[209] UCE Direct Testimony of Melissa Whited, p. 34, lines 583-585.

would make the economics of solar installation vary significantly.[210] UCE recommends that the current monthly netting process should continue until there is a better understanding of hourly netting impacts.[211]

Q. Should the current annual netting and crediting process be reformed?

A. Yes. Netting over a month or annual period, with kWh banking, is a flawed policy. Allowing excess generation in one period (e.g. a non-summer month) to offset consumption in another period when wholesale energy prices, and generation, transmission and distribution capacity requirements are likely to be different (e.g. higher-priced summer months), is economically inefficient. Not only does it unfairly compensate DG exports at certain times, it sends a poor price signal to DG owners, which may incent consumption or generation decisions that are not least cost for the system and all ratepayers.

Q. What kind of reforms would be more economically efficient?

A. I agree with the OCS that hourly (or perhaps sub-hourly) interval netting is a better way to assign costs and compensate NEM customers for exported energy, since the consumption of, and compensation for excess generation, ought to reflect the then-current value of energy and capacity. Lessening the netting interval would send a superior price signal.

[210] UCE Direct Testimony of Melissa Whited, p. 34, lines 592-593.
[211] UCE Direct Testimony of Melissa Whited, p. 34, lines 587-589.

Q. Can such a reform be made overnight?

A. No. The current rate structure does not include a time varying rate for either consumption or exported energy. In addition, the necessary metering is not in place to implement hourly interval netting.

Q. What does this mean for the NEM program?

A. A time-varying rate structure may take some time to develop, and it may require a pilot program(s) before any extensive rollout to a mandatory (i.e. non "opt-in" or "opt-out") rate design.

Further, as a practical matter, for customers without "smart meters" capable of recording real-time consumption and either total generation or more practically, generation exports, hourly or more frequent netting is impossible.

In addition, existing NEM customers have become familiar with the monthly netting process and it may take some time to ensure they understood and were in a position to optimize their consumption and excess generation for their own benefit and that of the system overall.

Q. What reforms could be implemented in the meantime?

A. A number of Commissions in other jurisdictions have focused on the crediting mechanism for excess generation as a first step. Instead of crediting and banking excess kWh, they have approved plans to convert the kWh into a monetary value based on the then-current value of that exported energy.

Additionally, I agree with the OCS that there should be dollar crediting on a customer's bill each month. Monetary crediting over kWh banking provides a better link to the market value of exported energy.

Q. How long a period should the monetary credits roll over?

A. As one means of assuring DG systems are sized appropriately relative the host customer's consumption, at the end of an annual period, the credits would be zeroed. Any remaining funds could then be allocated to other programs deemed to be in the public interest, for instance to assist low income customers, like the current program requires.

D. Effective Price Signals

Q. Do the intervenors support demand charges as proposed in the Company's three-part rate design for proposed Schedule 5?

A. Overall, and as discussed above, no intervenor supports the use of demand charges for residential customers. Below I provide some examples of the many reasons demand charges are not supported, and are recommended to be rejected, along with the rest of the Company's proposed rate design.

Sierra Club witness Clements argues that demand charges will not incent residential customers to respond to the demand price signals because they are not able to do so.[212] She further explains that the price signals customers receive from demand charges are inefficient and will not incent reduced consumption because "one bad afternoon can result in more than doubling a monthly electricity bill."[213] Additionally, Ms. Clements argues that even "sophisticated energy users would require education" to understand how the new demand charge rate structure would impact their electric bills.[214] The OCS echoes similar comments about residential customers needing to be educated about demand charges because residential customers are not used to thinking about demand, what drives their demand, and how they could manage demand charges.[215]

UCE witness Whited also explains that demand charges send inefficient prices signals because the price signal from a demand charge is concentrated "into the single hour of the month – the hour of the customer's individual maximum demand."[216] Additionally, she argues that implementing a demand charge will not lead to overall reduced energy usage because the energy charge is reduced significantly.[217] Further, Ms. Whited suggests that "[d]emand charges have a fundamental flaw, even when designed to apply only

[212] Sierra Club Direct Testimony of Allison Clements, p. 18, lines 327-331.
[213] Sierra Club Direct Testimony of Allison Clements, p. 23, lines 416-419.
[214] Sierra Club Direct Testimony of Allison Clements, p. 23, lines 420-422.
[215] OCS Direct Testimony of Michele Beck, p. 11, lines 237-242.
[216] UCE Direct Testimony of Melissa Whited, p. 24, lines 390-393.
[217] UCE Direct Testimony of Melissa Whited, p. 24, lines 395-397.

during certain hours each day."[218] She argues that "[a] more effective price signal would encourage customers to reduce energy consumption in each and every hour that the system is stressed, not just for the single hour that an individual customer reaches his or her own maximum demand."[219]

Vivint Solar witness Plagemann asserts that if residential demand charges are ever considered, they should "at a minimum: (i) be applicable to all residential customers in the same fashion; (ii) be properly communicated and understood by all customers; (iii) reflect the actual incremental costs of the customer's usage or the actual cost of interconnection; and (iv), be accompanied by data and/or technology allowing a customer to manage his/her peak demand and incurrence of those charges."[220] Mr. Plagemann further argues that demand charges are merely a strategy used by utilities to recover costs, while poorly reflecting "actual incremental costs to the grid."[221] Fellow Vivint Solar witness Collins explains that demand charges could lead to a reduction of peak usage because they are a large portion of a customer's bill, but since residential customers "have little visibility into their kilowatt usage in any given hourly period" their ability to reduce demand is minimal.[222] He further argues that residential customers "lack

[218] UCE Direct Testimony of Melissa Whited, p. 26, lines 444-445.
[219] UCE Direct Testimony of Melissa Whited, p. 24, lines 400-402.
[220] Vivint Solar Direct Testimony of Thomas Plagemann, pp. 6-7, lines 107-112.
[221] Vivint Solar Direct Testimony of Thomas Plagemann, p. 7, lines 123-124.
[222] Vivint Solar Direct Testimony of Richard Collins, p.10, lines 212-216.

the sophistication, resources, and technology to adjust time-based demand habits in any meaningful" way.[223]

Vote Solar argues that demand charges do not "provide an easily "actionable" price signal to consumers."[224] Additionally, Vote Solar claims that "RMP's customers do not have real-time metering, and even if they did, it would be impossible for them to sufficiently monitor their real-time usage to try to determine when their peak demand is likely to occur, and to reduce their consumption during that unknown peak hour."[225]

Further, Vote Solar asserts that for "customers to even know when their demand charges are being set; such knowledge would require near constant monitoring of real-time consumption data, which RMP does not collect (much less disseminate to customers)."[226]

Lastly, Vote Solar states that "[i]f RMP wants to send customers actionable price signals to reduce peak consumption and encourage energy efficiency, it should have proposed TOU rates instead."[227] TOU rates are preferable because they allow customers to "differentiate between on and off-peak periods," which will "provide better and more effective price signals."[228]

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[223] Vivint Solar Direct Testimony of Richard Collins, pp.10-11, lines 216-218.
[224] Vote Solar Direct Testimony of David W. DeRamus, p. 72, line 1409.
[225] Vote Solar Direct Testimony of David W. DeRamus, p. 72, lines 1410-1412.
[226] Vote Solar Direct Testimony of David W. DeRamus, p. 73, lines 1425-1428.
[227] Vote Solar Direct Testimony of David W. DeRamus, p. 72, lines 1419-1420.
[228] Vote Solar Direct Testimony of Rick Gilliam, p. 32, lines 664-665.

Q. Do you agree that demand charges are unnecessary or inappropriate for residential NEM customers?

A. Not necessarily. As I explained in my Direct Testimony, demand charges can be justified under cost causation principles to recover T&D costs since T&D systems are mostly fixed cost in nature and are designed to meet aggregate peak demand. Specifically, TOU and coincident[229] demand charges can send a better price signal than demand charges that are based on maximum billed demand in each billing cycle, and better reflect cost causation principle of ratemaking. Even though I disagree that all types of demand charges are inappropriate for residential customers, I do agree that properly designed TOU or time-differentiated energy charges can reflect changes in hourly energy prices, which allows the Company to recover many of the fixed T&D service costs and better reflect market prices for energy.

However, much of this is academic for now. As I and the intervenors have noted, the Company may not currently have the metering in place that would allow for measurement of coincident or TOU demand, as well as other time varying rates.

Q. What do you recommend?

A. I recommend that the Commission consider in the future both TOU-based and coincident peak or TOU demand-based rate schedules that allow for customer choice. To make bill impacts more gradual, the Company could start with a small demand charge or small

[229] Insofar as customers have a solid understanding of when coincident peaks are likely to occur.

peak/off-peak energy price differential. This allows customers to have a billing history under the new rate structure before significant bill changes occur. As part of the foundation for either type of rate structure, the design process would be better informed by additional data collection and analysis to better understand how demand charges compare to TOU energy rates at sending price signals to NEM customers, leading to load shifts to lower cost, off-peak periods. This may be an appropriate exercise for a general rate case.

IV. SUMMARY CONCLUSIONS AND RECOMMENDATIONS

Q. Please outline your conclusions and recommendations to the Commission.

A. Based on my analysis, I make the following conclusions and recommendations:

- Customers should not be forced to pay a much higher cost for distributed solar from their neighbors if the utility can offer it at a much lower cost from large projects after consideration of the total costs of generation, transmission and distribution.
- At the same time, utilities should not overlook distributed generation as an important, potentially economic resource in their system planning.
- Customers who obtain power from the grid, regardless of whether they also supply some of their own generation, must pay an appropriate cost-based rate for that service.
- Under traditional utility ratemaking, a utility is not entitled to recover "lost revenues," but it is entitled to recover its prudently-incurred costs.

- Effective price signals can be provided by time-based demand charges.
- A future distributed generation rate design should consider both demand-based and TOU-based time varying rates, implemented gradually to ensure bill impacts are modest, at least initially, and become well-understood by customers.
- A future distributed generation rate design should send accurate price signals to all customers, corresponding to the cost and value of consumption and export periods they are in effect, which requires appropriate metering, data communication and customer understanding.

Q. Does this conclude your testimony?

A. At this time, yes.