BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

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IDAHO PUBLIC
UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO ESTABLISH NEW SCHEDULES FOR RESIDENTIAL AND SMALL GENERAL SERVICE CUSTOMERS WITH ON-SITE GENERATION.	CASE NO. IPC-E-17-13

REBUTTAL TESTIMONY

OF BRIANA KOBOR ON BEHALF OF VOTE SOLAR

JANUARY 26, 2018

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1 Introduction

Q. Please state your name and business address.

A. My name is Briana Kobor. My business address is 986 E Princeton Avenue, Salt Lake City, UT 84105.

Q. On whose behalf are you submitting this rebuttal testimony?

A. I am submitting this rebuttal testimony on behalf of Vote Solar.

Q. Did you submit direct testimony in this proceeding?

A. Yes. My direct testimony includes an introduction to Vote Solar and a summary of my qualifications in addition to my substantive testimony and recommendations.

Q. What is the purpose of your rebuttal testimony in this proceeding?

A. This rebuttal testimony responds to the direct testimony filed by intervenors and the Idaho Public Utilities Commission ("the Commission") Staff ("Staff") on December 22, 2017.

Q. Please describe how your rebuttal testimony is organized.

A. Following this brief introduction, the second section of my rebuttal testimony identifies two significant areas of agreement among intervenors to this case. The third section responds to the direct testimony of Staff. The fourth section responds to the direct testimony of the Idaho Irrigation Pumper's Association ("IIPA"). Finally, the fifth section summarizes recommendations I make in this rebuttal testimony, in addition to the recommendations I outlined in my direct testimony.

Q. Please summarize your findings.

A. After reviewing the December 22, 2017 filings, I find that Staff and intervenors in this docket largely agree on two significant issues: (1) customers should be able to reduce behind-the-meter consumption without discrimination; and (2) Idaho Power Company's ("Idaho Power" or "the Company") request to place net energy metering ("NEM") customers in a separate rate class should be rejected in this docket, and the Company, parties, and the Commission need further study prior to any modifications to Schedule 84.

In addition, I support Staff's conclusions that the Company has not provided evidence in this case to justify the creation of a separate rate class for solar customers. However, while I do not understand Staff to be suggesting that the Commission adopt any of its cost allocation examples in this docket, I do disagree with some of Staff's assumptions in developing portions of its testimony. Specifically, Staff's NEM customer subgroup non-coincident peak ("NCP") measurement is not supported by the cost-causation basis Staff purports to apply. Rather than measuring NCP at the NEM-specific group peak, it is more appropriate and more supported by cost-causation principles to allocate distribution costs based on NEM customer demand at the time of the overall residential NCP due to the fact that NEM and non-NEM customers share distribution equipment and costs are driven by the cumulative peak loads on that equipment in the cost-of-service study. NCP is used in cost-of-service studies to allocate costs of distribution equipment to large and diverse classes because it often approximates the cost-causing peaks on the distribution equipment dedicated to serving the large class. However, when equipment serves multiple classes, or subgroups, the connection between peaks on the distribution equipment and individual class or subgroup peaks no longer holds, and the connection between NCP and costs no longer exists. Since the Company serves NEM customers from the same distribution system equipment as the larger non-NEM residential class, the residential class' NCP as a whole approximates the cost-causing peaks on the equipment and should be used to allocate those costs. There is no connection, and certainly none in the record, between the NEM-subgroup NCP and cost-causing peak loads on distribution system equipment.

I also found several apparent errors in Staff's calculated comparison of 2015 Demand Side Management ("DSM") avoided costs with the retail rate. When I correct those errors, I conclude that Staff's direct testimony overestimated the alleged over-payment to NEM customers. When corrected, the alleged $100.63 per customer per year over-payment is reduced to only $85 per customer per year.[1]

I understand that Staff does not propose any modifications to Schedule 84 and presents a calculation of hourly net billing with excess generation credited at an avoided cost for illustrative purposes only. I agree with Staff that no modification of Schedule 84 should be made now, and find that any consideration of the merits of Staff's illustrative proposal to be premature.

Staff's illustrative "placeholder" analysis purporting to demonstrate that NEM customers are overcompensated for exported generation under Schedule 84 is incomplete. That conclusion can only be accurately made after an analysis of the long-term benefits and costs associated with distributed generation, which Staff

[1] Even with these corrections, I still find Staff's calculation incomplete for the reasons described further in this testimony.

has not yet conducted. In fact, to the extent evidence exists, as provided in Sierra Club's direct testimony, the evidence indicates that benefits may exceed costs. Until determining the long-term benefits and costs associated with NEM in a future docket, the Commission does not have the requisite information with which to evaluate whether or not NEM customers are overcompensated or whether any change is needed to Schedule 84.

In addition, even if the Commission were to determine that Schedule 84 should be modified after having a complete record on benefits and costs, Staff's illustrative hourly net billing structure is only one of many possible responses, each of which comes with potential administrative costs and complications. Implementation of hourly net billing would be a complex change with many potential embedded policy considerations that have not been and cannot practically be considered in this docket. Indeed, Staff appears to have significantly modified the structure of its net billing proposal in Dr. Morrison's second revised direct testimony, but has not addressed this change in the testimony. This change in Staff's methodology and the fundamental policy choices underlying it underscores why the current docket is ill-suited to make any changes to Schedule 84. A comprehensive evaluation of Staff's proposal, in addition to the full menu of potential modifications based on the benefits and costs of each potential modification and the many embedded policy considerations, cannot practically be considered in this docket.

Additionally, Staff notes that NEM customers probably have a lower cost-of-service than other customers, but Staff does not quantify the amount of the lower cost. I note the $85 per NEM customer "over-payment" for exported electricity that Staff's framework alleges is less than the roughly $175 that NEM customers are over-paying in relation to the cost of serve them, on average, as estimated in my direct testimony. This implies that even if one were to accept Staff's placeholder analysis of the alleged "over-payment" for excess generation, the NEM program, as a whole, may still provide a net benefit to non-participating customers.

In addition, the overall small scope of the issue should not be overlooked. The rate impact on non-participating customers is defined by Staff as *de minimis*.[2] I calculate that even if one accepts Staff's framework—which does not include that NEM customers are currently paying more than their cost to serve under current rates—the costs at issue from the alleged over-payment for NEM exports for an average non-participating residential customer are only $0.015/month or $0.18/year. This is not only small in absolute terms; it is small compared to many actual cross subsidies that inherently exist in a diverse customer class like residential customers.

As a result, I find that the Commission should give this issue due consideration, including full consideration of the benefits and costs of Staff's illustrative proposal as well as a range of alternatives to it, in a separate docket. However, if the Commission were to ultimately adopt a policy similar to Staff's illustrative hourly netting and avoided cost export rate, I recommend that the Commission implement a clear, forward-looking grandfathering policy that provides protection

[2] Donohue Di. 13:3-8 (Dec. 22, 2017).

to existing customer investments and ensures that customers investing in new distributed generation know the basic terms of their compensation when they submit their application. In the case that Schedule 84 is modified, the Commission should adopt a Grandfathering Deadline effective 60 days following the effective date of an order that implements the new compensation method.

Finally, while I agree with IIPA that the Company's proposal to separate NEM customers into a new rate class is premature, I also find that IIPA's direct testimony confuses the difference between the services provided by Idaho Power to its NEM customers and the services NEM customers provide to Idaho Power. IIPA's direct testimony also contains a number of recommendations with which I disagree. These issues are described in detail in the body of this rebuttal testimony.

Q. Please summarize any additional recommendations you make in this rebuttal testimony.

A. In addition to the recommendations I made in my direct testimony, I also recommend the following in response to direct testimony filed by Staff and intervenors to this case:

- The Commission should recognize the right of all customers to reduce behind-the-meter consumption through any choices and technologies, without discrimination, and any future discussion of modification to distributed generation rates should focus on the compensation customer-generators receive for exported electricity under Schedule 84.

- The Commission should find that it is premature to consider Staff's illustrative analysis of hourly net billing at avoided costs and should defer consideration of any changes to Schedule 84 until after a separate docket determines the benefits and costs of net metering. Only <u>if</u> the Commission decides to modify Schedule 84 after a future benefit cost analysis, should the Commission focus on which of the full menu of potential modifications is appropriate based on the benefits and costs of each potential modification. Staff's "placeholder" is only one possible option, and has limitations not addressed in this docket.
- The Commission should instruct the parties that—to the extent the cost of serving NEM customers is determined—distribution costs should be allocated based on the broader class NCP because it more closely matches cost-causation peaks than the NEM-subgroup NCP, which does not correspond to cost-causing peaks.

2 <u>Staff and intervenors agree on two fundamental issues</u>

Q. Based on your review of the direct testimony filed by Staff and intervenors in this docket, were you able to identify any significant areas of agreement?

A. Yes. After reviewing the direct testimony filed by Staff and intervenors on December 22, 2017, I was able to identify areas of agreement on two significant issues: (1) customers should be able to reduce behind-the-meter consumption without discrimination; and (2) the Company's request to place NEM customers in a separate rate class should be rejected, and there is a need for further study prior to any modifications to Schedule 84.

2.1 Customers should be able to reduce behind-the-meter consumption without discrimination

Q. Did you take a position in your direct testimony on whether or not customers should be able to reduce behind-the-meter consumption without discrimination?

A. Yes. My direct testimony recommends that the Commission recognize customers' rights (1) to choose the amount of energy to purchase from the grid, (2) to reduce consumption of grid-supplied electricity by any combination of conservation, efficiency, and self-production the customer chooses to implement on his or her side of the meter, and (3) to lower utility bills and save money by reducing consumption of grid-supplied electricity. As I note in my direct testimony, these personal freedoms include the right to install solar generation equipment at the customer's site and to safely interconnect to the utility grid without discrimination.[3]

Q. Did other parties to this proceeding take a position on this issue in their direct testimonies?

A. Yes. Numerous parties including Staff,[4] Idaho Clean Energy Association ("ICEA"),[5] Idaho Conservation League ("ICL"),[6] Sierra Club,[7] and Snake River

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[3] Kobor Di. 50:20-51:3 (Dec. 22, 2017).
[4] Donohue Di. 4:11-18.
[5] King Di. 17:8-20 (Dec. 22, 2017).
[6] Otto Di. 8:6-9 (Dec. 22, 2017).
[7] Beach Di. ii (Dec. 22, 2017).

Alliance/NW Energy Coalition ("SRA/NWEC")[8] all took similar positions. In support of their position, Staff stated:

> Because it allows customers to offset their own consumption in the same way that customers have always been able to offset their own electric consumption through reduced usage, energy efficiency, natural gas and wood space heat, and all other methods. The Company does not concern itself with what happens on the customer's side of the meter for any other customers, and I do not believe it appropriate in this case either.[9]

Similarly, ICL states: "All customers have a right to reduce energy consumption behind the meter. Because reducing individual consumption is no different from any other member of the customer class, policy consideration for distributed energy systems should focus on excess energy only."[10]

Q. Do you have any recommendations based on this information?

A. Vote Solar agrees with the positions of Staff, ICEA, ICL, Sierra Club, and SRA/NWEC on this issue. I recommend that the Commission's decision in this case acknowledge the right of all customers to reduce behind-the-meter consumption without discrimination and indicate that future discussions regarding rate changes should focus on the compensation customer-generators receive under Schedule 84.

2.2 The Commission should not make any change to Schedule 84 until further study

Q. Did you take a position in your direct testimony on whether the Commission should reject the Company's request to place NEM customers in a separate

[8] Levin Di. 25:12-14 (Dec. 22, 2017).
[9] Donohue Di. 4:11-18.
[10] Otto Di. 8:6-9.

rate class and whether further study is needed before considering any modification of Schedule 84?

A. Yes. My direct testimony recommends that the Commission reject the Company's proposal to place NEM customers in a separate rate class and suggests that the Commission open a new docket to examine the long-term benefits and costs associated with distributed generation in Idaho Power's service territory and to use the results of such a docket to evaluate whether or not any changes are necessary to the retail rate NEM program.[11]

Q. Did other parties to this proceeding take a position on this issue in their direct testimonies?

A. Yes. Staff and every intervenor who filed direct testimony on December 22, 2017, recommend rejecting Idaho Power's proposed separate rate class, and instead, recommend various methods to further evaluate distributed generation prior to implementing any change to rates for NEM customers.

Q. Do you have any additional response to the positions of other parties on this issue?

A. Yes. I agree with Mr. R. Thomas Beach's direct testimony on behalf of Sierra Club regarding best practices for evaluating the benefits and costs of distributed energy resources.[12] Mr. Beach presents results from a recent Ratepayer Impact

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[11] Kobor Di. 10:19-12:11.
[12] Beach Di. 7:14-14:31.

Measure ("RIM") test he conducted that included only a subset of the full benefits and costs categories that the Commission should consider in a future analysis.[13] While I agree with Mr. Beach's use of the RIM test for the conclusions he draws from it, I note that the more comprehensive cost tests Idaho employs for DSM programs, such as the Total Resource Cost ("TRC") test, should also be conducted. The RIM test offers a single, narrowly-focused assessment of benefits and costs from the non-participating ratepayer perspective, but leaves out many important considerations. The Regulatory Assistance Project highlights some of the problems with the RIM in discussing its use for energy efficiency programs:

> Very few, if any, states use the RIM test as the primary determinant of cost-effectiveness for their energy efficiency programs, in part because it can easily foster counterproductive outcomes. For example, a program to install **less efficient** air conditioners would increase electricity consumption, thereby reducing utility fixed costs per kWh and reducing overall rates as a result. Accordingly, such an energy **inefficiency** program would pass the RIM test.[14]

It will be important that the Commission examine distributed generation from the broader perspective of all customers in a future value of net metering docket. Unlike the RIM test, the TRC and the Societal Cost tests consider benefits and costs to all customers. The TRC test is limited to energy benefits and costs, while the Societal Cost test includes non-energy benefits from a societal perspective. Therefore, using the TRC and Societal Cost tests, in addition to the RIM test, is a

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[13] *Id.* at 13, Table 2. Mr. Beach also indicates that an update of this analysis, in a future docket looking specifically at the benefits and costs of NEM, would likely demonstrate additional net benefits when all categories are included. *Id.* 13:8-11.

[14] Jim Lazar and Ken Colburn, *Recognizing the Full Value of Energy Efficiency*, Regulatory Assistance Project (Sept. 2013), at p. 17, 17 n.27, http://www.raponline.org/wp-content/uploads/2016/05/rap-lazarcolburn-layercakepaper-2013-sept-9.pdf. (emphasis added).

balanced, multi-perspective approach. As I noted in my direct testimony, I expect that a good faith undertaking to capture the full range of benefits of distributed solar generation may result in a valuation of distributed generation above the retail rate.[15]

3 Response to the Direct Testimony of Staff

Q. How do you respond to the direct testimony filed by Staff?

A. I respond to three issues raised by Staff's direct testimony: (1) Staff's analysis supporting the conclusion that there is no evidence to justify a separate rate class for NEM customers; (2) Staff's qualitative review of cost-causation by NEM customers; and (3) Staff's illustrative example of one possible modification to Schedule 84.

3.1 Staff's analysis supporting the conclusion that there is no evidence to justify a separate rate class for NEM customers

Q. What is your response to Staff's direct testimony that there is no evidence to justify a separate rate class for NEM customers?

A. I agree with Staff's conclusion that there is no evidence to support segregating NEM customers into a separate rate class. In support of this conclusion, Dr. Michael Morrison examined load data from NEM and non-NEM residential customers and found "there are no meaningful differences between net metering and non-net metering customers in the quantities of electricity used, differences in conditions of service, time, nature, and pattern of use."[16] I reviewed Dr.

[15] Kobor Di. 75:2-4.
[16] Morrison Di. 4:25-5:4 (Dec. 22, 2017).

Morrison's direct testimony on the average consumption patterns of NEM and non-NEM customers and agree with his conclusions on this issue.

3.2 <u>Staff's qualitative review of cost-causation by NEM customers</u>

Q. Did Staff conduct any cost-based analysis of NEM customer consumption?

A. Staff did not conduct any cost-based analysis of NEM customer consumption, but did discuss the "consumption characteristics that cause the Company to incur fixed costs."[17] Staff defines cost-causing consumption characteristics as contribution to coincident peak ("CP"), group NCP, and individual peaks.[18] In the most recent cost-of-service study the Company conducted in latest general rate case, the Company allocated costs to customers based in part on various measures of CP (namely the 3CP/12CP method) as well as class NCP.[19] It does not appear that individual customer peaks were used as an allocator in the most recent study; therefore, a comparison of this measure is not relevant to cost-causation.[20] While a comparison of only the relative magnitude of consumption at the time of system CP and total class NCP (without also looking at the relative total consumption and revenues paid by those customers) provides only a limited view of the cost difference among groups of customers, it does provide some useful context. When comparing NEM and non-NEM customer demand at the time of system peak, Staff found that NEM customers consumed less at the time of system peak.[21] Based on this finding, Staff noted:

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[17] *Id.* at 16:17-18.
[18] *Id.* at 16:17-20.
[19] Larkin Di., Exhibit 30, pp. 4-8, Case No. IPC-E-11-08 (June 1, 2011).
[20] *Id.*
[21] Morrison Di. 18:10-14.

> Power consumed at coincident peak is an important component of the Coincident Peak factor used to allocate fixed generation and transmission costs in Cost-of-Service studies. Had the Company performed a Cost-of-Service Study, it would likely have allocated slightly less generation and transmission plant cost to net metering customers. Given the large fraction (94%) of residential net metering systems using solar generation, it isn't surprising that summertime coincident peak consumption of net metering customers is reduced.[22]

While I do not believe that this comparison tells the whole story of the relationship between NEM customer demands as well as generation and transmission costs,[23] I generally agree with Staff that solar reduces contribution to CP demand and therefore costs. Because solar generation operates at the time of Idaho Power's system peak, solar generation contributes to meeting demand at the hours in which it is most valuable for production and transmission-related costs. This phenomenon is recognized in the analyses I conducted in my direct testimony and should be fully recognized in any future cost-of-service study that examines NEM customers.

Q. Do you agree with Staff's use of NCP demand for distribution cost allocation?

A. While I generally agree with Staff's characterization of class NCP demand as an important cost-causing characteristic of a large class served by distribution equipment dedicated primarily to that class, I disagree with the way in which Staff has measured class NCP for the NEM customer subgroup. Dr. Morrison notes that

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[22] *Id.* at 18:14-24.

[23] The relationship between NEM customer demands as well as generation and transmission costs must be examined in the context of a full cost-of-service study where costs are allocated based on consistent allocation factors and compared with revenues received to determine whether or not the studied class of customers is paying its fair share of costs under current rates.

"[a]s a group, net metering customers peak during the winter rather than during the summer"[24] and finds that NEM customers' average NCP was greater than that of non-NEM customers.[25] While Dr. Morrison is simply comparing consumption data—to the extent that such a comparison may be used to examine NEM customers in a future cost-of-service study, the cost-related implications of this comparison should be considered before applying the NCP for NEM customer cost allocation.

While class NCP is a common and well-justified allocator for distribution-related costs for a large customer group—like the residential class as a whole—the reason for using that allocator is important. Class NCP is used to approximate peak loading on substations, main feeders, and other equipment serving primarily one class. Specifically, residential class NCP is supposed to approximate the peak loading on distribution equipment serving primarily residential customers and because peak loading is the cost-causing activity, NCP approximates cost responsibility for the equipment. This methodology works when distribution equipment loads are driven by the primary customer class served by them. While there are certainly exceptions, residential customers tend to be served by common feeders, and likewise, commercial and industrial customers may be served by different feeders than residential customers. This is expected, given how cities and towns are typically organized and the fundamentally different types of customers that comprise the residential and industrial classes.

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[24] Morrison Di. (Rev.) 19:5-6 (Jan. 11, 2018).
[25] *Id.* at 19:2-5.

In contrast to the residential class as a whole, the NEM customer subgroup is not served by dedicated feeders. Residential NEM customers are typically located throughout residential areas and contribute to the local area loads in conjunction with non-NEM customers located in the same area of the distribution system. That is, distribution equipment cost-causation is the peak load on the equipment serving both NEM and non-NEM customers; NEM customer cost causation is those customers' contribution to the peak loads on the shared equipment, not the peak of the NEM subgroup occurring at another time and day. If solar customers are to be examined in a cost-of-service study, their distribution costs should be allocated based on their load contribution at the time of peak loading on the distribution equipment serving them, which is at the general residential NCP, not at the NCP unique to the NEM customer subgroup. The cost-causing peaks on the distribution system equipment serving NEM customers will be at the period of overall residential class peaks, not the time of the dispersed NEM-subgroup NCP. According to Staff, the NEM customer subgroup reached their collective peak on December 18, 2016, at the hour ending at 9:00 a.m., while the residential class reached its peak on July 26, 2016, at the hour ending at 7:00 p.m.[26] Staff compared the average residential peak on July 26 to the average NEM customer peak on December 18.[27] As explained above, these are not comparable for cost

[26] This definition of class NCP differs slightly from the residential class NCP defined by the Company in Kobor Di., Exhibit No. 902, Response to Request No. 57b. Because this section was developed in response to Staff's direct testimony, I adopt Staff's definition in this section.
[27] Morrison Di. 16:22-24; Morrison Di. (Rev.) 16:21-25.

causation. In response to discovery on this topic, Staff explains the basis for looking to NEM customers' NCP as follows:

> In an idealized cost allocation scenario, the costs of distribution equipment would be allocated based on each group's contribution to the peak loading of each distribution plant component; however, because this would require a separate analysis of each component, this is not always practical. Outside of the idealized scenario discussed above, distribution plant is often allocated based on each class' share of non-coincident peak.[28]

While I do not disagree with Staff's statement, generally, I disagree that the premise leads to Staff's implicit conclusion that the NEM-related peak on a December morning approximates peak loading on distribution equipment that is shared by NEM and non-NEM customers alike or that it has comparable cost causation to the residential peak on a July evening. Simply because "distribution plant is often allocated based on each class' share of non-coincident peak"[29] may be true across a large class with equipment serving primarily that class, it does not hold true when applied to a different peak by a subset of co-located customers separated in a cost-of-service study but who are not served by different dedicated equipment.

As I stated in my direct testimony, and consistent with the explanation above, the National Association of Regulatory Utility Commissioners ("NARUC") Electric Utility Cost Allocation Manual indicates that local loads are major factors in sizing distribution equipment, and it is <u>as a consequence of this fact</u> that class NCP is used to allocate the costs associated with these facilities.[30] It is unlikely

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[28] Staff's Response to Vote Solar's First Set of Data Requests ("Staff to VS"), Response to Request No. 5c (Jan. 16, 2018). Attached hereto as Exhibit No. 903.
[29] *Id.* (Exhibit No. 903).
[30] Kobor Di. 61:8-62:7 (citing NARUC, *Electric Utility Cost Allocation Manual*, pp. 96-97 (1992)).

that the NEM customer peak on a December morning approximates local area peak demand that drives distribution investment. Those customers are disbursed across the utilities' system and served from equipment dominated by the loads of non-NEM customers. It is the peak demand of non-NEM customers, who vastly outnumber the NEM customers served from distribution equipment serving both subgroups, that will drive local area peak demand that the NCP is intended to approximate.

Notably, while Idaho Power's cost-of-service analyses erroneously allocated distribution costs based on NEM customer exports in addition to consumption, the Company does correctly allocate costs to loads at the time of the overall residential class NCP, not the NEM-specific NCP occurring at a different time of day and season.

Q. If NCP is correctly measured for both NEM and non-NEM customers at the time of the residential class NCP, how does the distribution system cost-causing usage compare?

A. According to Staff, when demand at the time of residential NCP (July 26, 2016, at the hour ending at 7:00 p.m.) is measured for NEM and non-NEM residential customers, NEM customers consumed an average of 2.351 kW while non-NEM customers consumed 2.992 kW.[31] Thus, despite their larger than average total consumption, at the time the distribution system serving NEM customers was most constrained (because it was also serving non-NEM customers) NEM customers had lower distribution system loads. This suggests that distribution

[31] Staff to VS, Response to Request No. 5b (Exhibit No. 903); Morrison Di. 16:22-25.

costs of NEM customers are lower than non-NEM customers because distributed generation helps to reduce the loading on local distribution facilities, thus reducing the need for upgrades and wear and lowering system costs.

Q. What does Staff conclude based on their comparisons of consumption data?

A. Staff concludes:

> Had the Company performed a Cost-of-Service Study, it is difficult to determine whether it would have allocated more or less distribution plant to net metering customers than to non-net metering customers. I should reiterate that these differences are quite small relative to the total variability among Schedule 1 customers. Had the Company conducted a Cost-of-Service study, it is likely that they would have determined the differences in the overall costs of serving these two groups to be very small.[32]

Q. Do you agree with this conclusion?

A. While I agree with Staff that it is difficult to determine the level of costs that would have been allocated to NEM customers versus non-NEM customers if a cost-of-service study where to be conducted, the evidence from the consumption data comparison illustrated above indicates that NEM customers should be allocated less cost-of-service, on a per customer basis, as their consumption at the time of the cost-causing peaks is lower than non-NEM customers.

That said, I also agree with Staff's conclusion that a cost-of-service study would likely demonstrate the differences between costs related to NEM and non-NEM customers are quite small relative to the total variability among Schedule 1 customers. So, to summarize: while NEM customers cost less to serve if separated out in a cost-of-service study, the difference between NEM cost-of-service and

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[32] Morrison Di. 19:14-23.

non-NEM cost-of-service is likely no greater than the difference in cost-of-service among many other potential subgroups within the larger customer classes.

3.3 Consideration of Staff's illustrative proposal to modify Schedule 84

Q. Please summarize Staff's illustrative proposal to modify Schedule 84.

A. Ms. Stacey Donohue states:

> I also recommend that the Commission initiate a docket in which the Company and interested parties can work together to determine the compensation structure for excess generation based on the avoided cost of the resource. When that process is complete, I recommend that the Commission direct the Company to file a revised Schedule 84 reflecting the agreed-upon avoided cost rate and the net-hourly metering.[33]

While Staff does not recommend modifying Schedule 84 in the present docket, and explicitly recommends "a new docket be initiated to determine the avoided cost value that most accurately reflects the value of this resource,"[34] Staff goes on to provide an illustrative proposal to modify Schedule 84 using 2015 hourly avoided costs from the DSM program as a "placeholder."[35]

Q. What support does Staff offer for its illustrative proposal to adopt hourly netting and avoided cost credits in a future docket?

A. Dr. Morrison states:

> Net metering customers are being overcompensated for the energy that they produce. The value of excess energy provided by net metering customers is due, primarily, to the energy costs that it allows the Company to avoid; however, net metering customers are effectively compensated at full retail rates. As discussed earlier, Idaho Power's Schedule 1 and Schedule 7 retail rates are substantially higher than the Company's energy costs.[36]

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[33] Donohue Di. 23:3-10.
[34] *Id.* at 14:6-8.
[35] *Id.* at 15:9-10.
[36] Morrison Di. 9:20-10:3.

Based on Dr. Morrison's analysis using "placeholder" costs, Staff characterizes the difference between the "placeholder" costs and the retail rate as a "cost shift" and a "current subsidy" and quantifies it at a level of $100.63 per net metering customer per year.[37] In other words, Staff identifies the "cost shift" to NEM customers to be the amount of an alleged overvaluing of exported electricity from NEM customers to the grid.

Q. Do you agree with Staff's characterization of the difference between 2015 DSM avoided costs and retail rates as a "cost shift" and a "current subsidy"?

A. I do not for two reasons. First, Staff's conclusions based on this "placeholder" analysis is not a "cost shift" as typically defined. Second, the "cost shift" calculation based on only one input is premature.

Q. Please explain how Staff's presentation of the difference between the "placeholder" costs and retail rates is a separate concept from a cost shift.

A. As commonly used, the term "cost shift" refers to a situation where one group of customers pays less than the cost the utility incurs to serve them, based on system-wide cost allocation principles, thereby leaving other customers in the utility's service territory with the burden of paying those costs under rate of return regulation. However, instead of focusing on the cost of service for grid-supplied electricity to NEM customers, Staff focuses on the compensation NEM customers receive for the electricity they provide to the utility (exported electricity). This credit value for electricity services provided to the Company is not an issue of "cost shift" (the cost of providing electricity to the NEM customer) but an alleged

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[37] Donohue Di. 12:2-5.

Company over-payment for services it receives—like any other allegation of uneconomic costs in the Company's revenue requirement.

Q. Have you identified any issues with Staff's calculation of the comparison between 2015 DSM costs and the retail rate?

A. Yes. While reviewing Staff's workpapers provided in response to discovery, I noticed that Staff used two avoided cost rates to value solar exports: one for all exports in the summer months (June-August) and a second for the remaining non-summer months.[38] This approach appears inconsistent with the methodology Staff described in response to discovery, which points to 2015 DSM avoided costs from the Company's 2013 Integrated Resource Plan ("IRP").[39] Unlike the two values Staff used, the DSM Avoided Costs in the 2013 IRP have five different values, which differ over two seasons (Summer and Non-Summer) and three hourly periods (Peak, Mid-Peak, and Off-Peak). It is not clear how Staff derived the two values it employed for summer and non-summer or why Staff did not use the five values provided in the 2013 IRP.

Because solar production varies throughout the day and year, and coincides with higher cost periods, the two values applied by Staff do not accurately value solar exports based on the proscribed DSM avoided costs. As a result, Staff undervalues NEM exports and therefore overstates the difference between 2015 DSM costs and the retail rate. I updated Staff's analysis to utilize the five periods actually

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[38] Staff to VS, Response to Request No. 1, File "Net Metering Analysis_171228," Sheet "Residential," Cells "B8883:C8883." This issue is also present in the revised workpapers provided by Staff to parties on January 24, 2018 in File "Net Metering Analysis_180123.xlsx," Cells "B8883:C8883."

[39] Staff to VS, Response to Request No. 2 (Exhibit No. 903).

provided in the 2013 IRP which Staff identified in discovery as the applicable avoided cost (2015 Summer On-Peak, Summer Mid-Peak, Summer Off-Peak, Non-Summer Mid-Peak, and Non-Summer Off-Peak). I also corrected two minor Excel errors.[40] The results are shown in Table 1 below, which corresponds to Table 1 in Dr. Morrison's direct testimony.

Table 1: Vote Solar's Update to Dr. Morrison's Table 1 provided in Morrison's Direct Testimony

Annual Average	NEM Excluding Schedule 84 Credit	NEM with Schedule 84 Credit (Current Rates)	NEM Staff Proposal
kWh Consumed	13,581	13,581	13,581
Excess kWh	3,644	3,644	3,644
Billed kWh	13,581	9,937	13,581
Bill before Excess Generation Credit	$1,265.08	$1,010.81	$1,265.08
Excess Generation Credit	N/A	N/A	$169.36
Final Bill	$1,265.08	$1,010.81	$1,095.72

After making these adjustments, the difference between what a NEM customer pays with and without the Schedule 84 credit is $254.27. Subtracting the "placeholder" value of exports based on the DSM avoided costs ($169.36) leaves a remaining difference of only $84.91. This is lower than the $100.63 presented in

[40] Staff's original analysis of NEM customer usage contained in the workpapers provided on January 16, 2018, appears to have accidentally omitted some usage data in the months of February and July. In addition, there was a minor spreadsheet error related to the calculation of residential usage by tier. While these issues appear to be largely corrected in the Updated Workpapers that Staff provided on January 24, 2018, one typo remains in Staff's Updated Workpapers, which accounts for a minor difference between Vote Solar's bill calculation for "NEM with Schedule 84 Credit" and the calculation found in Dr. Morrison's second revised direct testimony.

Dr. Morrison's direct testimony[41] as well as the $137.25 presented in Dr. Morrison's second revised direct testimony.[42, 43]

Q. Are there any other changes in Dr. Morrison's second revised direct testimony that impact the value of solar exports under Staff's proposal?

A. Yes. In the calculations underlying Staff's proposal in Dr. Morrison's second revised direct testimony, it appears that monetized excess energy credits are not allowed to offset the $5 customer charge and that customers are not compensated for the value of all of their exports in months where the credit for exports exceeds the cost of deliveries.[44] That is, despite being monetized, the credits for exported electricity are not fully fungible because they cannot be used to offset the customer charge, and any excess value during a month is forfeited, rather than being applied as a credit to a subsequent month's bill. This methodology is a change from Dr. Morrison's original direct testimony, in which monetized export credits were allowed to offset the customer charge and the export credit values were applied to the full volume of annual solar exports.

A portion of the alleged "cost shift" in Dr. Morrison's second revised direct testimony ($137.25) is therefore attributable solely to the change in methodology between the original and second revised versions of testimony. Specifically, Dr.

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[41] Morrison Di. (Rev.) 12:5.
[42] Morrison Di. (2nd Rev.) 12:5 (Jan. 25, 2018).
[43] The sensitivity of the "cost shift" number in Staff's analysis to modifications to the time periods and avoided cost values, as well as to spreadsheet errors, highlights how sensitive the valuation of solar exports can be to minor changes in methodology and inputs and further emphasizes the need to fully investigate the benefits and costs of distributed generation through a dedicated docket.
[44] Staff's Updated Workpapers, File "Net Metering Analysis_180123," Sheet "Residential," Cells "F8883:UX8895."

Morrison's second revised direct testimony's $116.80 value of Excess Generation Credit excludes any value for exports in a month when the value exceeds the kWh charge for deliveries that month. This new approach in Dr. Morrison's second revised direct testimony is a non-trivial policy change from Staff's original position but is not addressed in Dr. Morrison's second revised direct testimony.[45] In my analysis in Table 1, I maintained Dr. Morrison's direct testimony methodology and valued the full volume of solar exports. I do not adopt Staff's revised methodology from Dr. Morrison's second revised direct testimony because it confiscates the value of monetized "avoided cost" energy credits at the end of each month.

This change in Staff's methodology and the fundamental policy choices underlying it (whether to fully monetize export credits and make the credits fully fungible to offset charges) underscores why the current docket is ill-suited to make any changes to Schedule 84. A comprehensive evaluation of Staff's proposal, in addition to the full menu of potential modifications based on the benefits and costs of each potential modification and the many embedded policy considerations, cannot practically be considered in this docket. Moreover, discussing any changes to Schedule 84 is, itself, premature.

Q. Please explain why you find a conclusion regarding the need to modify Schedule 84 to be premature.

A. Staff expressly states that no change should be made to Schedule 84 in the present docket. I agree. Any consideration of the need for modification of Schedule 84,

[45] Morrison Di. (2nd Rev.).

including Staff's illustrative "placeholder," in this docket is therefore premature. Without the full benefit of facts from a complete analysis in a future proceeding, consideration of hourly net billing or any other potential modification to Schedule 84 necessarily prejudges the facts and conclusions of that future proceeding. For example, Dr. Morrison discusses the need to modify Schedule 84 and states: "[t]he value of excess energy provided by net metering customers is due, primarily, to the energy costs that it allows the Company to avoid; however, net metering customers are effectively compensated at full retail rates."[46] This prejudges what the value of excess energy is, and reaches a premature conclusion that an energy component is the "primary" value. A narrow focus on avoided energy costs excludes the many value streams provided by the net excess energy that NEM customers export to the grid such as generation, transmission, and distribution capacity benefits, avoided line losses, grid security benefits, fuel hedging benefits, and more. As demonstrated in the direct testimony of Mr. Beach on behalf of Sierra Club, a more complete analysis may show that distributed generation compensation at the retail rate undervalues rather than overvalues that generation.[47]

In fact, Staff acknowledges the need for a more thorough analysis that includes the study of benefits and costs prior to determination of the resource value of excess generation.[48] In her critique of the Company's proposal to study the

[46] Morrison Di. 9:21-25.
[47] Beach Di. 13:8-11.
[48] Donohue Di. 14:4-8.

benefits and costs of distributed generation only after implementing major changes by separating rate classes, Ms. Donohue states:

> Stakeholders were in favor of a study to determine the costs and benefits of net metering, but the Company made no indication that it might conduct the study after determining the need for separate rate classes. As a participant in those meetings, it was clear that stakeholders were interested in that study happening before a significant decision such as a rate class determination or pricing change was proposed.[49]

I find that the same critique could be applied to Staff offering a "placeholder," even for illustrative purposes only, prior to conducting a full benefit-cost study as stakeholders have consistently advocated.

Moreover, in her response to the Company's proposal to separate customer classes in the present docket to limit the issues in a future general rate case, Ms. Donohue states: "Limiting or expanding a future proceeding is not the correct basis on which to determine creation of new customer classes. That decision should be made based on evidence, not a desired process outcome."[50] That is correct.

While it appears that Staff is merely suggesting that a future proceeding include the study of possible avoided costs rates for hourly net generation, the scope of the future docket should not be limited to discussion of Staff's proposal. Rather, the future docket should first address the preliminary question of whether to modify Schedule 84 at all. The suggestion that Schedule 84 should be revised to replace retail rate compensation with hourly netting at an avoided cost rate is one possible modification that could be made to Schedule 84 in response to results

[49] *Id.* at 19:18-25 (emphasis in original).
[50] *Id.* at 21:2-5.

from a benefit-cost study, but this is not a change that should be prejudged absent full information including the potential costs of such a proposal.

Q. What are some of the costs of implementing hourly netting in Idaho Power's service territory?

A. Replacing retail rate NEM with a net billing scheme will carry substantial administrative costs such as a substantial increase to the quantity of billing data to be managed, billing systems that may need to be updated, and the need to calculate and to potentially re-calculate the export credit rate regularly. In addition, as with any more complicated rate, the more complex compensation structure will increase customer confusion, customer service calls, and time spent educating customers. A recent study has shown that individual customers may experience large variation in the proportion of their generated solar that is exported to the grid, resulting in significant uncertainty as to the value of the energy generated under hourly net billing.[51] This will make the decision to invest in distributed generation more complex and discourage some customers from the investment; the confusion it causes will also likely increase calls to the Company and the Commission with questions and complaints.

Q. Even assuming Staff's suggestions that applying 2015 DSM avoided costs to exports and the current retail rate credit demonstrates an over-payment to NEM customers, do you still expect the benefits of implementing net billing to outweigh the costs?

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[51] Maddy Yozwiak, *The Impact of Shorter Netting, Increased Uncertainty for Consumers*, Public Utilities Fortnightly (Jan. 2018), p. 53. Attached hereto as Exhibit No. 904.

A. That is difficult to say as I do not have available information to quantify administrative costs associated with program implementation, and without information regarding the impact on the spectrum of NEM customers, it is impossible to predict what the market impact may be. I can state, however, that even under Staff's "placeholder" analysis, the total value of the alleged over-payment is minimal.

After making corrections to Staff's calculation as described above, the alleged over-payment is $85 based on the "placeholder" resource value of roughly $0.046/kWh, which is roughly half of the average retail rate. This value is less than the roughly $175 per customer that I estimate NEM customers are currently paying in excess of the costs to serve them.[52] Both of these values are approximate, at best, because of the limitations inherent in trying to make these calculations outside of a full general rate case. However, a comparison between the two values indicates that NEM customers' over-payment of their fair share of costs for the services provided to them by Idaho Power is more than double the alleged over-payment for the excess generation they provide to the Company. This implies that even if one were to accept Staff's "placeholder" analysis of the over-payment for the exported electricity, the NEM program as a whole may still be found to provide a net benefit to non-participating customers and therefore does not justify any change to the current NEM program.

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[52] Kobor Di. 72, Table 4.

Furthermore, Staff characterizes its own calculation of over-payments for excess generation as *de minimis* relative to class revenues.[53] Indeed, with current residential customer adoption levels, the total alleged over-payment from residential customers is only $84,485 per year under Staff's approach. This represents a cost to the average non-participating customer of $0.015/month or $0.18/year.[54] The cost shift from rural to urban customers, or dual fuel to electricity only customers, likely far exceeds the alleged NEM impact.

Q. What do you recommend based on these findings?

A. Even if we accept the assumptions underlying the calculated impacts, the minimal estimated impacts do not justify changes to Idaho's net metering policy at this time. The Commission has time to conduct a thorough investigation regarding the benefits and costs of distributed generation in Idaho prior to implementing any change to rate class definitions or compensation under Schedule 84. As I stated on direct, the reality remains that distributed generation penetration is still extremely low in Idaho Power's service territory and is expected to remain low for decades to come. The Commission should not accept any proposal to pre-define future modification of Schedule 84. Rather, the Commission should evaluate Staff's proposal for hourly net billing at an avoided cost rate only after conducting

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[53] Donohue Di. 13:3-8.

[54] For reference, if one adopts Staff's original calculation of a per customer over-payment of $100.63/year as presented in their direct testimony, this would result in a total alleged over-payment of $100,127 per year, which would impact the average non-participating residential customer by $0.018/month or $0.22/year. If one adopts the calculation in Dr. Morrison's second revised direct testimony, the per customer over-payment of $137.25/year would result in a total alleged overpayment of $136,564, which would impact the average non-participating residential customer by $0.025/month or $0.29/year.

further study of the long-term benefits and costs associated with distributed generation in a future docket.

Q. In the event that the Commission approves hourly net billing at an avoided cost rate in this proceeding, should existing customers be grandfathered?

A. Yes. While I do not support approval of any modifications to Schedule 84 in this proceeding, should the Commission nonetheless approve such a proposal, I recommend that the Commission implement a clear, forward-looking grandfathering policy that will provide protection to existing customer investments and ensure that customers investing in new distributed generation know the basic terms of their compensation when they submit their application. In the case that Schedule 84 is modified, the Commission should adopt a Grandfathering Deadline effective 60 days following the effective date of an order that implements the new compensation method. More detailed grandfathering recommendations are provided in my direct testimony.[55]

4 Response to the Direct Testimony of the Idaho Irrigation Pumpers Association

Q. How do you respond to the direct testimony of IIPA?

A. I agree with Mr. Anthony J. Yankel that the Company's proposal to separate NEM customers into a new rate class is premature.[56] However, I also find that his direct testimony confuses the difference between the services provided by Idaho Power

[55] Kobor Di. 86:5-87:15.
[56] Yankel Di. 12:18-21 (Dec. 22, 2017).

to its NEM customers and the services NEM customers provide to Idaho Power and contains a number of recommendations with which I disagree.

Q. Please describe how Mr. Yankel confuses the difference between the services provided by Idaho Power to its NEM customers and the services NEM customers provide to Idaho Power.

A. In discussing the minority of NEM customers who are "net zero customers," Mr. Yankel states:

> [T]he customer would only pay the customer charge, with no payment made to reflect the fact that the generation, transmission, and distribution facilities were all used to support the energy being brought to the customer as well as distributing the excess energy that is made at other time. It is intuitively obvious that such a customer is essentially paying nothing for its use of the generation, transmission, and distribution system for every hour during the month.[57]

This characterization has two main problems. First, it looks to only a subset of NEM customers: those who are net zero consumers. Second, it conflates the two distinct streams of service, flowing in different directions, exchanged between a NEM customer and the utility. During the hours in which a NEM customer demands more energy than her distribution-generation system produces, she takes delivery service from the utility and pays the retail rate for that service under the standard tariff. The fact that she may be "paying" by applying credits she earned by providing electricity to the utility during other hours does not mean that the electricity service she used was free.

During the hours in which a NEM customer generates more energy than is needed behind-the-meter, she provides exported energy to the utility grid at her meter and

[57] *Id.* at 6:11-16.

is credited for that service at the retail rate under Schedule 84. Contrary to Mr. Yankel's statement, she does not use the generation, transmission, and distribution system during the hours in which she exports energy. The NEM customer's responsibility for exported energy ends at the point of her meter when ownership of that energy is transferred to the utility. It is the utility that utilizes the grid to bring that energy to nearby customers, and it is the nearby customers who compensate the utility for the provision of that service.

Additionally, Mr. Yankel states: "The entire cost-of-service (cost and benefits) needs to be addressed and then an appropriate rate design must be developed that recovers costs (less benefits) in a manner that is understandable by all parties, including the customers."[58] This is incorrect to the extent Mr. Yankel suggests that benefits associated with exported distributed generation belong in a utility cost-of-service study, as exported generation is not a service provided by the utility. As I recommended on direct, evaluation of rate design for distributed generation should separately focus on (1) the cost to serve customer-generators for the services that are provided to them by the utility; and (2) the appropriate compensation for services that are provided by the customer-generator to the Company.

Q. Which of Mr. Yankel's recommendations do you disagree with?

A. I disagree with two of Mr. Yankel's recommendations: (1) his suggestion that a subsequent proceeding should develop a unique allocation method for production

[58] *Id.* at 7:10-12.

demand and energy costs for NEM customers; and (2) that the subsequent proceeding should take the form of a workshop.

Q. Please explain the issue with Mr. Yankel's suggestion that a subsequent proceeding should develop a unique allocation method for production demand and energy costs for NEM customers.

A. Mr. Yankel appears to take issue with the fact that solar may not be generating during specific winter peak hours and contends that:

> The Workshop should develop a more granular differentiation of production demand and energy costs for the Solar Net Metering customers, because the number of customers generating excess are significantly different between the various 9-months that the Company defined as Non-Summer.[59]

There are two problems with this suggestion. First, the cost-of-service study in the Company's latest general rate case included a production demand allocation factor known as 3CP/12CP. Under this method, customer class loads at the time of system peak demand during each of the 12 months were considered in the development of allocation factors associated with production costs. If solar customers had a higher than usual demand during some winter months due to the peak falling outside of sunlight hours, that would already be captured in the allocation factor. Second, and most importantly, it appears Mr. Yankel is advocating for the development of a production cost allocator unique to NEM customers. Such an undertaking would be discriminatory to those customers. Cost-of-service should be calculated for all classes and customers based on consistent, system-wide principles. If there is a need to modify any aspect of the

[59] *Id.* at 10:20-11:2.

cost-of-service study methodology, it must be applied to all customer classes and not only to a NEM-specific class.

Q. Please explain the problem with Mr. Yankel's suggestion that a subsequent proceeding take the form of a workshop.

A. While I agree with Mr. Yankel that future discussion of the long-term benefits and costs should involve collaborative work between the utility and interested parties, I do not believe that the complex issues at hand could be addressed exclusively through a workshop. The Company, alone, holds much of the information and the data necessary to determine the long-term benefits and costs. This information asymmetry means it has an inherent advantage over all other parties. A collaborative process, without the right to full discovery, testimony under oath, and cross-examination to obtain and test information held exclusively by the Company tends to extenuate that advantage. Rather than relying only on a workshop process, I recommend a two-phase docket including evidentiary hearings in order to produce a robust result that can be relied on by this Commission in future rate determinations.

5 Summary of Recommendations

Q. Please summarize your recommendations.

A. In addition to the recommendations I made in direct testimony, I also recommend the following in response to testimony filed by Staff and intervenors to this case:

- The Commission should recognize the right of all customers to reduce behind-the-meter consumption through any choices and technologies, without discrimination, and any future discussion of modification to distributed generation rates should focus on the compensation customer-generators receive for exported electricity under Schedule 84.

- The Commission should find that it is premature to consider Staff's illustrative analysis of hourly net billing at avoided costs and should defer consideration of any changes to Schedule 84 until after a separate docket determines the benefits and costs of net metering. Only <u>if</u> the Commission decides to modify Schedule 84 after a future benefit cost analysis, should the Commission focus on which of the full menu of potential modifications is appropriate based on the benefits and costs of each potential modification. Staff's "placeholder" is only one possible option, and has limitations not addressed in this docket.
- The Commission should instruct the parties that—to the extent the cost of serving NEM customers is determined—distribution costs should be allocated based on the broader class NCP because it more closely matches cost-causation peaks than the NEM-subgroup NCP, which does not correspond to cost-causing peaks.

Q. Does this conclude your rebuttal testimony?

A. Yes. It does.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this 26th day of January, 2018, served the foregoing **REBUTTAL TESTIMONY OF BRIANA KOBOR ON BEHALF OF VOTE SOLAR** upon all parties of record in this proceeding, via the manner indicated:

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Before the Idaho Public Utilities Commission

Case No. IPC-E-17-13

Vote Solar

Kobor, DI-REB Testimony

Exhibit No. 903

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO ESTABLISH NEW SCHEDULES FOR RESIDENTIAL AND SMALL GENERAL SERVICE CUSTOMERS WITH ON-SITE GENERATION	**CASE NO. IPC-E-17-13** **STAFF'S RESPONSE TO VOTE SOLAR'S FIRST SET OF DATA REQUESTS**

The Staff of the Idaho Public Utilities Commission responds as follows to Vote Solar's First Set of Data Requests to Commission Staff.

REQUEST NO. 1: Please provide all work papers to support all witness testimony you filed in this case, including but not limited to all underlying data and analyses supporting any numerical calculations, tables, and/or figures presented in your testimony. Please provide work papers in native format with formulas and links intact. To the extent that statistical software, other than Excel, was used in the development of your analysis please provide the log file, script and/or code written in the software language that was used, including the original data and output data. Please consider this an ongoing request and timely provide any additional work papers supporting additional testimony filed in this proceeding.

STAFF RESPONSE NO. 1: As described on pages 10 and 11 of his testimony, Dr. Morrison used data provided by the Company through Staff's Production Request No. 8 in his analysis of net metering consumption patterns. Dr. Morrison's calculation of net metering consumption and billing under current rates and Staff's proposal can be found in cells E8789 through 8895 of the "Residential" tab in the spreadsheet "Net Metering Analysis_171228.xlsx." These cells have been highlighted in Blue.

Dr. Morrison used data provided by the Company through Staff's Production Request No. 12 in his analysis of non-net metering consumption patterns. Dr. Morrison's calculation of non-net metering consumption and billing under current rates and Staff's proposal can be found in cells E8790 through E8825 of the "Regional Summary" tab in the spreadsheet "Non Net Metering Analysis_171228.xlsx." These cells have been highlighted in Blue.

The data obtained from these spreadsheets, and used as the basis for Tables 1 and 2, and Figures 2, 3, and 4 of Dr. Morrison's testimony can be found in the spreadsheet "TestimonyGraphics_171228.xlsx." All three spreadsheets are included in File Name Idaho Power PR #1 – 3 on the CD produced with Staff's Response to Idaho Power Company's First Production Request.

This response is sponsored by Idaho Public Utilities Commission Staff Engineer, Michael Morrison, PhD.

REQUEST NO. 2: On page 11, lines 7-12 Mr. Morrison's Direct testimony refers to "2016 DSM avoided cost rates" that were used to estimate an average net metering customer's bill under Staff's proposal.

a. Please provide a reference to the docket number in which those rates were developed and a reference to the Commission Order approving the rates.

b. Please provide a copy of the filing(s) relied upon to obtain the 2016 DSM avoided cost rates used in Mr. Morrison's analysis.

STAFF RESPONSE NO. 2:

a. Dr. Morrison used the 2015 costs from the Company's 2013 IRP, Technical Index (Appendix C), Page 77, Docket No. IPC-E-13-15.

b. The Company's filing can be found at the Idaho Public Utilities Commission website:

www.puc.idaho.gov/fileroom/cases/elec/IPC/IPCE1315/20130701IRP APPENDIX C TECHNICAL INDEX.PDF.

This response is sponsored by Idaho Public Utilities Commission Staff Engineer, Michael Morrison, PhD.

REQUEST NO. 3: Please confirm that Mr. Morrison's statements on page 9, lines 11-17, regarding a customer's "share" of costs and whether customers "are subsidized" and on page 12, lines 5-7, regarding a "cost shift" are based on a comparison of a customer's bills to the average per-customer cost of service, rather than a customer's bills to that particular customer's cost of service or that customer's load contributions to the class loads used to allocate costs to the class in the cost of service study.

STAFF RESPONSE NO. 3: As stated on page 4 of Dr. Morrison's testimony, the Company did not provide a cost of service study, so neither of these statements is correct.

This response is sponsored by Idaho Public Utilities Commission Staff Engineer, Michael Morrison, PhD.

REQUEST NO. 5: Please reference page 16, lines 17-20, and Table 2 of Mr. Morrison's Direct.

a. Please identify the distribution plant component costs caused by the Net Metering Group's non-coincident peak load.

b. Please identify the Net Metering Group's load at 7:00 pm on July 26, 2016 (i.e., during the Non-Net Metering Group's Non Coincidental Peak hour). Please provide this in the same format as the data in Table 2 (which appears to be a per customer average).

c. To the extent that net metering customers share distribution equipment with non-net metering customers, and the consumption characteristic that causes the Company to incur the cost of that shared distribution equipment is the peak load on the shared equipment, please explain why the net metering customer group's non-coincident peak, rather than the group's contribution to peak loading on the distribution equipment at issue, is an appropriate cost causation allocator.

STAFF RESPONSE NO. 5:

a. The Company did not provide a cost of service study in this case, and Staff did not perform such an analysis, so it is not possible to provide the information requested by Vote Solar.

b. The average net metering load for the hour ending at 7:00 pm on July 26th, 2016 was 2.351 kW.

c. Dr. Morrison disagrees that Vote Solar's proposed allocator premise is appropriate. In an idealized cost allocation scenario, the costs of distribution equipment would be allocated based on each group's contribution to the peak loading of each distribution plant component; however, because this would require a separate analysis of each component, this is not always practical. Outside of the idealized scenario discussed above, distribution plant is often allocated based on each class' share of non-coincident peak.

This response is sponsored by Idaho Public Utilities Commission Staff Engineer, Michael Morrison, PhD.

REQUEST NO. 6: Reference Direct Testimony of Stacey Donohue, page 5, lines 1-4. Please identify each of the capacity costs that are lowered by net metering customers.

STAFF RESPONSE NO. 6: The Company did not provide a cost of service study in this case, so the specific capacity costs which are lowered are unknown.

This response is sponsored by Idaho Public Utilities Commission, Technical Analysis Program Manager, Stacey Donohue, MPA.

REQUEST NO. 7: Reference Direct Testimony of Stacey Donohue, page 10, lines 15-17. Please confirm (1) that the reference to a below average usage customer receiving a subsidy is based on a comparison between below average usage customer bills and the cost to serve a customer with an average load, and (2) that this statement is <u>not</u> based on a cost of service analysis for below average use customers as a class, or an analysis of the below average usage customer's actual contribution to class loads during the hours to which costs are allocated to the class as a whole in the cost of service study.

STAFF RESPONSE NO. 7: Neither of these statements were based on a cost of service study because the Company did not provide such a study in this case.

This response is sponsored by Idaho Public Utilities Commission, Technical Analysis Program Manager, Stacey Donohue, MPA.

Dated at Boise, Idaho, this 16th day of January 2018.

Sean Costello
Deputy Attorney General

Technical Staff: Michael Morrison
Stacey Donohue

i umisc prodreq/ipce17.13scmmsd response to Vote Solar prod req

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 16TH DAY OF JANUARY 2018, SERVED THE FOREGOING **STAFF'S RESPONSE TO VOTE SOLAR'S FIRST SET OF DATA REQUESTS,** IN CASE NO. IPC-E-17-13, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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Jo Nelson

SECRETARY

Before the Idaho Public Utilities Commission

Case No. IPC-E-17-13

Vote Solar

Kobor, DI-REB Testimony

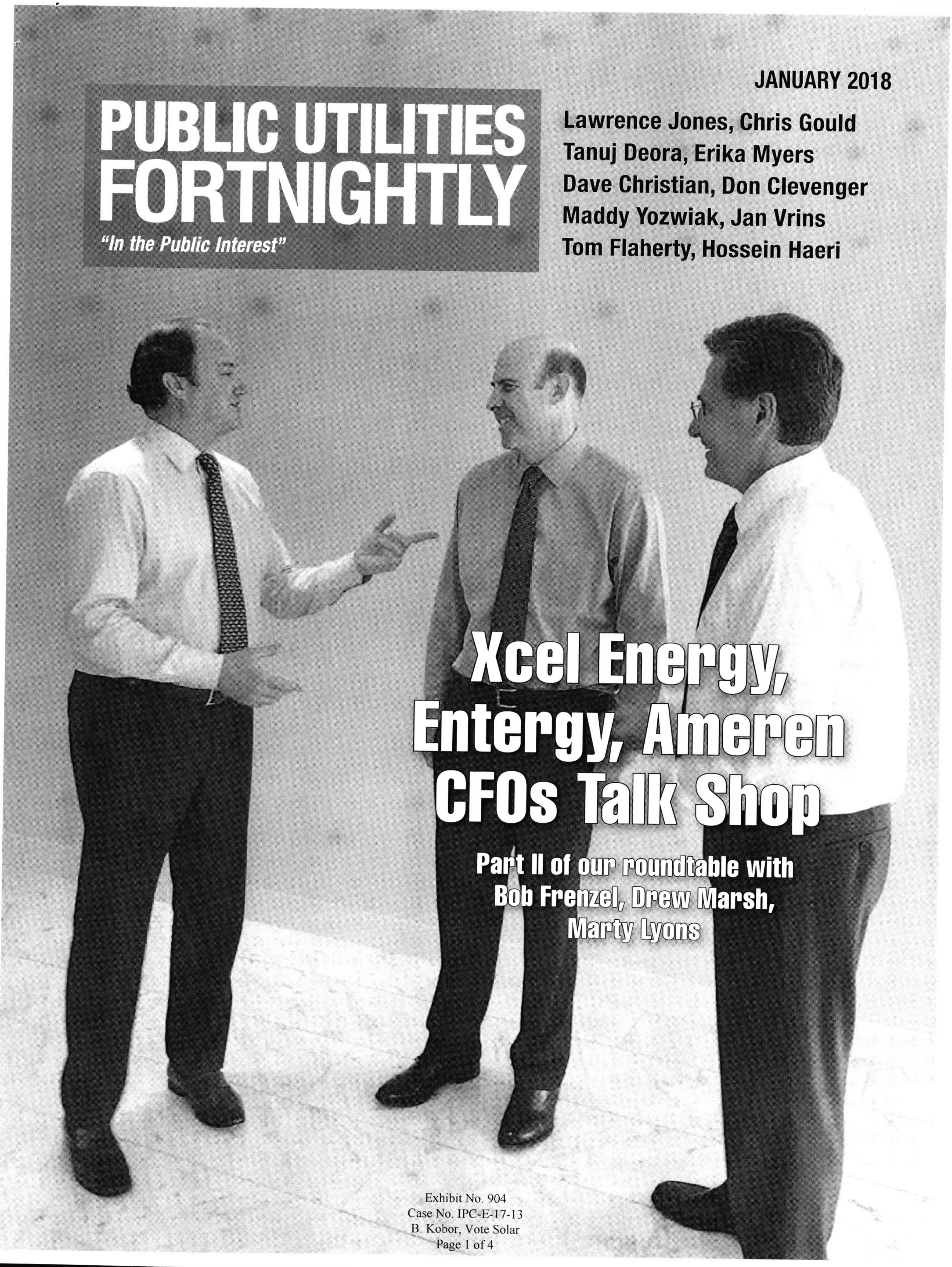
Exhibit No. 904

JANUARY 2018

PUBLIC UTILITIES FORTNIGHTLY

"In the Public Interest"

Lawrence Jones, Chris Gould
Tanuj Deora, Erika Myers
Dave Christian, Don Clevenger
Maddy Yozwiak, Jan Vrins
Tom Flaherty, Hossein Haeri



Xcel Energy, Entergy, Ameren CFOs Talk Shop

Part II of our roundtable with Bob Frenzel, Drew Marsh, Marty Lyons

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In PUF, Impact the Debate

PUBLIC UTILITIES FORTNIGHTLY
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Has your organization joined the nearly two hundred members of the PUF community to impact the debate?

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Cover photography: From left to right, Xcel Energy CFO Bob Frenzel, Entergy CFO Drew Marsh and Ameren CFO Marty Lyons, at our recent CFO Roundtable. Photographer: PUF staff.

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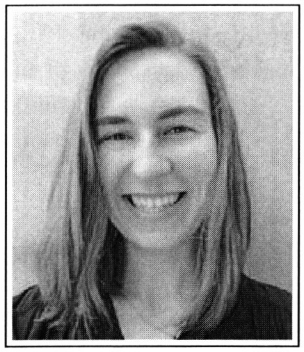

The Impact of Shorter Netting

Increased Uncertainty for Consumers

By Maddy Yozwiak

Several states – such as Nevada, Arizona and Utah – recently replaced their net metering policies with a construct called net billing. The customer pays the normal retail rate for any net imports, and is credited at a second rate for any net exports.

While much of the debate centered on the value of this export rate – is it at, above, or below retail? – the new policies also changed a second, less obvious aspect of net metering: the 'netting period' over which net exports or imports are determined.

The 'net' in net metering and net billing indicates that a customer is only charged on the difference between their total imports and exports for a period of time. For example: I import ten, I export seven, and I'm charged for three. The 'netting period' simply defines when this subtraction occurs.

For net metering, the imports and exports are traditionally netted at the end of each month. For the new net billing arrangements, however, utilities have proposed reconciling the two at much shorter intervals – every hour, fifteen minutes, or even instantly.

These shorter periods increase the variation in the amount of net exports calculated across different customers' bills. This is because a shorter period can expose any real-time mismatches between a customer's usage and production. This match-up can vary significantly between households. The result is that an individual customer considering whether to install solar has less certainty about what their savings will be.

To illustrate this dynamic, Vote Solar analyzed a sample of around twenty-four thousand solar customers' usage in the Arizona Public Service territory. The range of net exports under an hourly netting period varies by as much as twenty-two percent based on the customer. The average falls at forty-seven percent of solar generation, but can be thirty-seven percent (for the twenty-fifth percentile) up to around fifty-nine percent (for the seventy-fifth percentile).

See Figure One.[1]

Similarly, exports assessed on an instantaneous basis range from thirty-five percent at the twenty-fifth percentile to seventy-two percent at the seventy-fifth percentile, with an average of fifty-five percent. Note that the shorter netting period shifts the distribution of net exports to the right, which results in more net exports relative to hourly.

The amount of net exports a customer makes, under a net billing policy, directly determines the value of their solar generation. When the credit for any net exports is lower than the price of any net imports, solar generation that has a high percentage of net exports is going to be worth less than solar generation with a smaller share.

For example, take a customer on the upper end of the APS sample, with a net export percentage of around eighty percent. If that customer had, instead, only twenty percent net exports, the value of their solar generation would be 1.2 cents per kilowatt-hour higher in the first year, assuming an export rate of two cents per kilowatt-hour below retail.[2]

The impact of net exports on the value of a customer's solar generation depends on the export rate. The lower the export rate, the lower the value of solar generation, given a certain net export percentage.

See Figure Two.[3]

The distribution of customers' net exports is going to be different for each utility. For example, customers in Michigan do not behave in the same way as customers in Arizona, nor does the sun shine in the same way in both places. The analysis we've provided should only be viewed as illustrative,

Maddy Yozwiak is the regulatory research manager at Vote Solar, a non-profit advancing solar access at the state-level nationwide.

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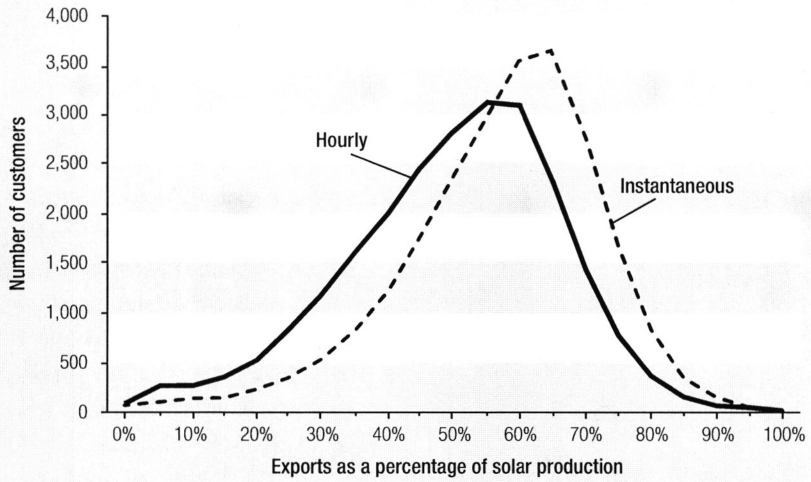
FIG. 1 **NET EXPORTS (% OF PRODUCTION), APS NEM CUSTOMERS, 2015**

Net exports, measured on an hourly and instantaneous basis, as a percentage of annual solar production for APS NEM customers in 2015.



and not as representative of the impact for another utility.

But the overall impact of shorter netting periods is straightforward: increased uncertainty. The basic question for an individual considering solar is, "Does this decision make economic sense for me?" The answer becomes significantly more difficult to determine when hourly, fifteen-minute or real-time historical usage must be crunched to estimate savings. Never mind parsing how these values can change over time, or overlap with other policy changes.

Remember the twenty-two percent variation under hourly netting seen earlier in the APS sample? Another way to think of this number is that the value of nearly a quarter of customers' generation is uncertain. An individual could be a high net exporter, or they could be a low exporter, but because they will not know for sure, they need to assume a quarter of their generation could swing either way.

The challenge for policymakers is to deeply consider the practical implications of shorter netting periods before implementing. In particular, we highlight three distinct areas to assess:

First, the distribution of net exports for the customer base of the unique utility in question must be calculated to understand the range of potential impacts on customers. The data used in this analysis should be complete, statistically significant for the applicable customer group, and broadly available to other stakeholders.

Second, data and metering infrastructure requirements for more granular billing must be evaluated, to ensure unnecessary costs are not incurred with shorter netting periods. Recent experience in Utah demonstrates this risk.[4]

Finally, the utility must give customers access to their usage information at the same frequency as the netting period, so that they can effectively respond to price signals and manage their usage. PUF

FIG. 2 **DECREASE IN THE VALUE OF SOLAR GENERATION BY EXPORT RATE AND NET EXPORT PERCENTAGE**

How much the value of solar generation (dollars per kilowatt-hour) decreases by export percentage – assuming an export credit rate that falls the given amount below retail.

		_% of solar generation is net exports:										
		0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Export rate is $_/kWh below retail	$0.01	$ -	$(0.001)	$(0.002)	$(0.003)	$(0.004)	$(0.005)	$(0.006)	$(0.007)	$(0.008)	$(0.009)	$(0.010)
	$0.02	$ -	$(0.002)	$(0.004)	$(0.006)	$(0.008)	$(0.010)	$(0.012)	$(0.014)	$(0.016)	$(0.018)	$(0.020)
	$0.03	$ -	$(0.003)	$(0.006)	$(0.009)	$(0.012)	$(0.015)	$(0.018)	$(0.021)	$(0.024)	$(0.027)	$(0.030)
	$0.04	$ -	$(0.004)	$(0.008)	$(0.012)	$(0.016)	$(0.020)	$(0.024)	$(0.028)	$(0.032)	$(0.036)	$(0.040)
	$0.05	$ -	$(0.005)	$(0.010)	$(0.015)	$(0.020)	$(0.025)	$(0.030)	$(0.035)	$(0.040)	$(0.045)	$(0.050)

Endnotes:

1. Page 115 of Kobor Phase 2 Surrebuttal Testimony in Docket No. E-01933A-15-0322 at the Arizona Corporation Commission. http://docket.images.azcc.gov/0000182991.pdf.
2. This is not an LCOE analysis. We are only estimating the dollars per kilowatt-hour value of generation in the first year.
3. The 'retail rate' here is the equivalent volumetric charge that a customer could offset via net metering. The value of solar generation is the weighted average of the import price and export credit, given the net export percentage.
4. Short netting periods increase the volume of data the utility needs to collect in order to bill the customer. A fifteen-minute netting period will require four times as many data points as an hourly netting period, even though the utility cost recovery will be similar in both cases. As a result, the volume of data can cause complications and potential costs if the correct metering infrastructure is not deployed. An example comes from Rocky Mountain Power in Utah, where fifteen-minute netting was recently adopted. The meters the utility plans to deploy to accommodate the 15-min netting would not be AMR capable and are expected to require manual monthly readings.

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